H2Teesside Project

Planning Inspectorate Reference: EN070009

Land within the boroughs of Redcar and Cleveland and Stockton-on-Tees, Teesside and within the borough of Hartlepool, County Durham

The H2 Teesside Order

Document Reference: 8.11.14 Response to ExQ1 Socio-economics and Land use

Planning Act 2008

Applicant: H2 Teesside Ltd

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1.0 INTRODUCTION

1.1 Overview

1.1.1 This document has been prepared on behalf of H2 Teesside Limited (the 'Applicant'). It relates to an application (the 'Application') for a Development Consent Order (a 'DCO'), that was submitted to the Secretary of State for Energy Security and Net Zero ('DESNZ') on 25 March 2024, under Section 37 of 'The Planning Act 2008' (the 'PA 2008') in respect of the H2Teesside Project (the 'Proposed Development').

1.1.2 The Application has been accepted for examination. The Examination commenced on 29 August 2024.

1.2 The Purpose and Structure of this document

1.2.1 The purpose of this document is to set out the Applicant's responses to the Examining Authority's ExQ1 on Socio-economics and Land use, which were issued on 4 September 2024 [PD-008]. This document contains a table which includes the reference number for each relevant question, the ExA's comments and questions and the Applicant's responses to each of those questions, and is followed by appendices where they are referred to in the responses.

Table 1-1: Applicant's Responses to ExQ1 Socio-economics and Land use

EXQ1	QUESTION TO:	QUESTION:	APPLICANT'S RESPONSE
Q1.14.1	UKHSA, EA and LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body	Clarification/ Views sought. Paragraph 20.3.9 of ES Chapter 20 (Major Accidents and Disasters) [APP-073] states that a 5 km study area around the Proposed Development Site (the study area) has been considered recognising that this area of Teesside includes several installations regulated by the COMAH Regulations and Major Accident Hazards (MAH) pipelines which are regulated by the Pipelines Safety Regulations 1996. The study area has been selected on the basis that MAH sites greater than 5 km from the site are unlikely to be directly affected unless there is a Domino linkage with another site within the study area and this would be dealt with through the COMAH process. i. Does the UKHSA, EA and LAs, together with any other relevant Authority/ Body, agree with the 5 km threshold? If not, please state the reasons? ii. Can the Applicant please sign post the ExA to the document which summarises the Pipelines Safety Regulations 1996 requirements in relation to MAH/ COMAH pipelines?	Section 1.3 of the HSE guidance "A guide to the Pipelines Safety Regulations 1996", (see Appendix 1) which provides a summary of the Pipeline Safety Regulations 1996 requirements in relation to MAH/COMAH pipelines. Part III of The Pipelines Safety Regulations 1996 also provides requirements in relation to Major Accident Hazard pipelines.
Q1.14.2	**UKHSA, EA, LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body**	Views sought. The Applicant describes the Proposed Development as a 'First of its Kind' project in terms of scale stating that hydrogen production is a developing area. The Applicant further states that increasing investment in the sector is resulting in technological advancement (Paragraph 5.2.1 of the DAS [APP-034]). In light of the above: i. Can the EA, UKHSA, and/ or LAs, together with any other relevant Authority/ Body, comment on the Applicant's approach to the assessment of major accidents as set out in ES Chapter 20 [APP-073])? **ii.** Are the EA,UKHSA and LAs, together with any other relevant Authority/ Body, satisfied that the Applicant has identified and adequately assessed the potential risks associated with the Proposed Development, including the Hydrogen production and capture and compression of CO_2 together with its transport?	n/a
Q1.14.3	**Applicant/ EA**	Clarification/ Views sought. Table 20-2: Responses to the Statutory Consultation Feedback of ES Chapter 20 (Major Accidents and Disasters) [APP-073] sets out the EAs response where they noted several other issues and concerns, including in relation to the Preliminary Environmental Information Report (PEIR) missing a list of proposed dangerous chemicals and a proposed inventory. In response the Applicant has stated that a provisional chemical list is provided in ES Chapter 21 (sic) (Major	The Applicant can confirm this assumption is correct. The provisional chemical list is available in ES Chapter 20: Major Accidents and Disasters [APP-073], in Table 20-4.

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		Accidents and Disasters), but does not actually direct the reader to that list. It is assumed that the Applicant is referring to Table 20-4 of ES Chapter 20 (Major Accidents and Disasters) [APP-073]. Can the Applicant confirm the above assumption is correct? Does the EA consider that the Applicant's response in Table 20-4 of the above mentioned Chapter of the ES is adequate and can it confirm whether or not the other issues and concerns raised by them, as referred to in Table 20-2 have been addressed?	
Q1.14.4	**Applicant**	Clarification. The ExA notes in Paragraph 20.3.23 of ES Chapter 20 (Major Accidents and Disasters) [APP-073] states that the Applicant has had regular engagement with the Health and Safety Executive (HSE). Can the Applicant please provide a summary of the consultation which has taken place with HSE and provide copies of correspondence received from the HSE regarding the Proposed Development or signpost where such correspondence can be located in the submitted Application documentation?	The Applicant has engaged with the HSE regarding the Proposed Development and as part of the East Coast Cluster more broadly. A record of engagement is contained within the SoCG with the HSE submitted at Deadline 1 [REP1-015] which details all consultation undertaken to date between the two parties.
Q1.14.5	**Applicant**	Clarification. Paragraph 20.3.26 of ES Chapter 20 (Major Accidents and Disasters) [APP-073] notes that due to construction phasing, there may be a period following opening of Phase 1 where that phase will be operational and Phase 2 will be in construction. This paragraph notes the potential for a major accident and disasters event is increased in the event that construction and operational activities are occurring on adjacent sites. Can the Applicant explain what risk assessments, mitigation measures and necessary revisions to the Framework CEMP have/ will be undertaken to demonstrate that construction activities for Phase 2 can be conducted safely adjacent to the operational activities related to Phase 1?	. The Construction, Design and Management Regulations ("CDM") regulations will be followed as required throughout the design and construction phases of both Phase 1 and Phase 2 which will include the development of design Risk Register(s). These are live documents, maintained by the Project Manager throughout the design and construction phases of projects to identify and document risks, assign ownership, priority and mitigation measures. The COMAH Safety Report will be submitted 'within a reasonable time before start of construction' in line with the guidance from the HSE. It will demonstrate that major accident hazards and possible major accident scenarios have been identified and that the necessary measures have been taken to prevent such accidents and to limit their consequences for human health and the environment. A formal risk assessment of the potential hazards of simultaneous operations is anticipated to be carried out where activities at the Proposed Development are in close proximity to existing operational facilities (including Phase 1 of the Proposed Development) and there is a potential for conflict, to inform the COMAH Safety Report and the development of the CEMP. This is pertinent to the Proposed Development with two distinct phases of development.
Q1.14.6	**Applicant, EA, UKHSA, HSE, and LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body**	Clarification/ Views sought. Paragraph 20.3.27 of ES Chapter 20 (Major Accidents and Disasters) [APP-073] states in addition to the Proposed Development there are other neighbouring	i. The COMAH Safety Report has to demonstrate that the risks during the different phases of the Proposed Development have been reduced to ALARP (As Low As Reasonably Practicable)

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		projects which are ongoing with different delivery timescales, ie HyGreen and NZT Power. These projects will be in different stages of implementation through the construction, commissioning and operation of Phases 1 and 2 of the Proposed Development. The Proposed Development Site is located within an area which has several COMAH installations where the risks or consequences of a major accident may be increased due to the proximity of the sites to each other. i. Please can the Applicant explain what appropriate modelling, safe distance and plant design will be adopted to demonstrate that risks are as 'Low As Reasonably Practicable'? In addition to the above, it is noted that the Proposed Development is to form part of a cluster of existing and other proposed developments that are or will be COMAH sites, which may increase the potential risks associated or consequences of a major accident due to the presence of a domino group . ii. Can the Applicant please explain how the embedded measures in the design and construction of the Proposed Development will be sufficient to reduce or off-set any increased potential risks associated with major accidents due to the domino group? iii. Does the, UKHSA, HSE, EA and LAs have any comments on the Applicant's assessment of the existing and proposed domino developments in respect of Credible Scenarios and embedded mitigation? The ExA notes from Paragraph 20.3.23 of ES Chapter 20 (Major Accidents and Disasters) [APP-073] that the Applicant has been in consultation with the HSE. iv. Can the Applicant and/ or relevant LAs advise whether the HSE have provided any site plans showing HSE Zones related to other uses (existing or proposed) in the area of the Proposed Development, which have implication for COMAH and whether the HSE have issued any 'Advise Against' or 'Do Not Advise Against' advice letters in relation to the Proposed Development?	before the Competent Authority (HSE and EA) will allow construction, commissioning, and operation of the Proposed Development to commence. ALARP is demonstrated through appropriate design and embedded mitigation, and through safe construction commissioning and operation of the project. ii. The Safety Report will also need to consider both risks to the Proposed Development from adjacent sites and risks to adjacent sites from the Proposed Development. The Applicant is aware of other COMAH and Hazardous Substances Consent sites in the vicinity as shown on Figure 10-7 Hazardous Sites in the ES [APP-116], but this will be kept under review and considered during the development of the COMAH Safety Report. iii. Not for the Applicant. iv. The HSE will undertake initial zoning for the site following consultation on the Hazardous Substances Consent application by the local planning authority. Given that the final inventory for the Proposed Development is contingent on completion of the design process, this has not been submitted at this stage. HSE guidance is that this should be submitted 6-12 months prior to hazardous substances being present on the site. As such, it is understood this submission is also still to be made for the NZT/NEP and HyGreen developments. However, given the anticipated low sensitivity of the existing and proposed adjacent developments (assumed to be restricted to workplaces with Level 1 sensitivity comprising normal working population), these developments are allowed within the Inner Zone of a major hazard installation and therefore are expected to receive 'Do not Advise Against' advice from the HSE.
Q1.14.7	**Applicant**	Clarification. Paragraphs 20.3.29 - 20-3.30 of ES Chapter 20 (Major Accidents and Disasters) [APP-073] sets out the assumptions that have been made in relation to the construction and operational phase of the Proposed Development. i. Can the Applicant please explain what assumptions have been made in the assessment about the design of, and safety and control systems for,	i. Standard mitigation measures for hydrogen systems will be used. Whilst the employment of carbon capture technology at the scale proposed on the Proposed Development is novel , the generation of hydrogen via steam reforming of methane is a proven, tried and tested method for hydrogen production which according to a Johnson Matthey review, was first carried out at

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		any novel technology and/ or processes used within the Proposed Development, given current industry standards are not yet in place? ii. Please also explain the Applicants level of confidence in these assumptions for the purpose of reaching a conclusion, in regard to paragraph 20.9.1 'Summary of Residual Effects' in this Chapter of the ES, of residual effects being 'not significant', given the novel nature of the Proposed Development?	Teesside in 1936. Since then, steam reforming has become the most common way of generating hydrogen as noted by Hydrogen UK, the IEA and the UK Government (provided in Appendices 2, 3 and 4 respectively). The knowledge on how to safely produce, handle and store hydrogen is documented and well understood. The Proposed Development is subject to COMAH Regulations 2015, which aim to prevent and mitigate the effects of major accidents involving dangerous substances to ALARP, through a hierarchy of embedded mitigation and safety and control systems. ii. The Applicant is confident in the assumptions made with regards to the 'not significant' determination for residual effects denoted in paragraph 20.9.1 'Summary of Residual Effects' in Chapter 20 of the ES. As an Upper Tier COMAH site, the COMAH Safety Report will have to demonstrate that risks have been reduced to ALARP, otherwise the Applicant will not receive permission from the CA to construct, commission and operate the Proposed Development.
Q1.14.8	**Applicant**	Clarification. Paragraphs 20.3.20 of ES Chapter 20 (Major Accidents and Disasters) [APP-073] sets out the assumptions that have been made for the operational phase of the Proposed Development and states at this stage in the Proposed Development, safety and control systems have not yet been designed, however, standard industry approaches to managing risk will be used. In addition, equipment such as process monitoring and safeguarding systems, and embedded mitigation, such as fire, flammable gas, toxic gas and leak detection, fire protection systems and emergency shutdown systems, will be installed as required. Can the Applicant please explain as the Proposed Development is a 'First of its Kind' Project what certainty can the ExA have that, at least in principle, the embedded design of the Proposed Development will be sufficient to prevent, control and mitigate major accidents during the operational phase?	The Applicant has extensive experience of the implementation of process monitoring and safeguarding systems, and embedded mitigation, such as fire, flammable gas, toxic gas and leak detection, fire protection systems and emergency shutdown systems, and as such is confident that the embedded design of the Proposed Development will be sufficient to prevent, control and mitigate major accidents during the operational phase. This is one of the key design processes that is currently ongoing during the design phase for the Proposed Development. As noted in the response to 1.14.7 above, while the Proposed Development is 'First of its Kind' with regards to the scale, steam reforming of hydrogen to produce methane is not new and has been conducted on Teesside since 1936. The understanding of appropriate systems design standards and mitigation for handling and storing hydrogen is well documented. Irrespective of the technical design of the project and the associated technology, all proposed developments are subject to COMAH Regulations 2015, which aim to prevent and mitigate the effects of major accidents involving dangerous substances, thereby imbedding in the required safety and control systems for any process, whether a novel design or a well-established design. As noted above, as an Upper Tier COMAH site, the COMAH Safety Report will have to demonstrate that risks have been reduced to ALARP, otherwise

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			the Applicant will not receive permission from the CA to commission and operate the Proposed Development.
Q1.14.9	**UKHSA, EA, and** **LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body**	Views sought. Please confirm whether you have any comments or observations with regards to the following paragraphs and/ or tables contained in the Applicant's ES Chapter 20 (Major Accidents and Disasters) [APP-073]: • Proposed Development Design and Impact Avoidance/ Minimisation (Paragraphs 20.5.1 - 20.5.25); • Impacts and LSEs, including the Shortlisted Major Accidents and Disasters Scenarios (Paragraphs 20.6.1 - 2.6.16); and • The 'Credible Scenarios Related to the Construction of the Proposed Development' (Table 20-3).	n/a
Q1.14.10	**LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body**	Views sought. Paragraphs 18.3.2 to 18.3.5 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] defines a Study Area for the socio-economic assessment. Are the extent of the Lower layer ((sic) (Local)) Super Output Areas (LSOA) and the Wider Impact Area: Middlesbrough and Stockton Travel To Work Area (TTWA), as set out in the document reasonable or do you consider they need to be drawn wider? If the latter please fully justify your reasoning. In addition to the above, Paragraph 18.3.3 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] states only a small proportion of the Hartlepool LSOAs lies within the boundary of the Proposed Development Site and therefore these areas have not been included in the H2Teesside Study Area. Do LAs, together with any other relevant Authority/ Body, agree with the Applicant that the Hartlepool LSOAs should be excluded from the study area? If not please provide your full reasoning as to why you disagree.	n/a
Q1.14.11	**LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body**	Views sought. Paragraph 18.3.6 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] sets out the assessment of the potential effects of the Proposed Development on baseline socio-economic conditions, whilst the socio-economic receptors are set out in Paragraph 18.3.7 of the same document. Table 18-1 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] sets out the criteria for assessing and classifying levels of receptor sensitivity based on professional judgement, whilst Paragraph 18.3.9 and Table 18-2 of the same document assesses the magnitude of the socio-economic impacts associated with the Proposed Development. Do LAs, together with any other relevant Authority/ Body, have any comments or observations on or in relation to the Applicant's approach to these assessments?	n/a

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Q1.14.12	**LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body**	Views sought. Paragraph 18.3.14 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] assesses the duration of the permanent and temporary effects. The short-term effects are of one year or less, medium-term effects of one to five years and long-term effects are for effects with a duration over five years. Do the LAs, together with any other relevant Authority/ Body, agree with the assessment? If not please fully justify your reasoning.	n/a
Q1.14.13	**Applicant and LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body**	Clarification/ Views sought. Paragraph 18.3.25 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] states the number of workers on site during the construction period for the Proposed Development will go up or down depending on the intensity of construction activity during this time. During the construction phase the peak number of workers present on site will be between approximately 800 and 1,300 workers. i. Can the Applicant please explain what data has been used to inform the assessment of peak number of workers on site during the construction phase? ii. Do the LAs, together with any other relevant Authority/ Body, have any comments or observations to make with regards to the assumptions set out? If so please fully explain your response.	i) The applicant has considered the following factors to inform the assessment of Construction phase estimates for the peak number of workers on site; • Project scope: Each component's complexity and size help determine the approximate manpower needed. • Preliminary design information which informed the approximate number of people required and how many you can "fit" in the area to safely construct the plant • Industry Standards: Estimators apply typical factors such as productivity rates, hours per unit of work, or established norms for similar work in the industry and corresponding region • Historical Projects: Data from similar projects are used to benchmark manpower requirements • Risk and uncertainty: given the early stage of the project, a contingency factor is added to manpower estimates to account for unknowns (typically 10-30%) ii) Using this, to identify the net additional site jobs in the construction phase, additionality assumptions for displacement, leakage and the multiplier were then used. The details of these assumptions can be found in Paragraphs 18.6.6 to 18.6.12 of ES Chapter 18 (Socio-economics and Land Use) [APP-071].
Q1.14.14	**Applicant, LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body**	Clarification/ Views sought. Paragraph 18.3.26 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] sets out the assumptions made in regard to the operational phase of the proposed Development, including the assumed number of workers employed in direct operational jobs per annum, whilst Section 18-4 of this Chapter sets out 'Baseline Conditions'.	i) The direct (gross) site jobs data estimate is based on benchmark data for similar complexity onshore facilities. This will be further refined in the detailed design stage. A reasonable worst case scenario was defined for the purposes of the EIA. Using this, to identify the net additional site jobs in the operational phase, additionality assumptions for displacement, leakage and the multiplier were then used. The details of these

EXQ1	QUESTION TO:	QUESTION:	APPLICANT'S RESPONSE
		i. Can the Applicant explain what data and assessments were used to make the assumptions in respect of the number of workers during the operational stage of the Proposed Development. ii. Do the LAs, together with any other relevant Authority/ Body, have any comments or observations with regards to the Applicants assumptions in this regard and do you agree that the Applicant's assessment presents a reasonable 'worst-case' approach based on the minimum scenario for employment at the Proposed Development? iii. Do the LAs, together with any other relevant Authority/ Body, have any comments or observations in relation to the assessment of the 'Baseline Conditions'? Paragraph 18.4.42 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] states that future projections for the H2Teesside Study Area and the Middlesbrough and Stockton TTWA are not available. In the absence of this information. iv. Can the Applicant explain how it has ensured the accuracy of the assessment of future socio-economic baseline conditions? v. Do the LAs, together with any other relevant Authority/ Body, have any comments or observations with regards to the future baseline conditions (see Paragraph 18.4.41 - 18.4.48 of the above mentioned Chapter of the ES)?	assumptions can be found in Paragraph 18.6.27 of ES Chapter 18 (Socio-economics and Land Use) [APP-071]. iv) The future baseline has been formed primarily from available Office for National Statistics data, by using population projections as a basis, which has also been supplemented by professional judgement. To note, the accuracy of future socio-economic baseline conditions is inherently uncertain as it is a future baseline and therefore a prediction. The Applicant notes in ES Chapter 18 [APP-071] in Paragraph 18.3.29 that the present day baseline is subject to a time lag between collection and publication which ultimately act as a limitation on data even for the present day. In addition, the latest dataset on population projections for local authorities has not been updated since 2018, which means that the data does not account for changes in population between 2018 and the time of writing (2024). Overall, these factors lead to a limit on the accuracy of the future baseline.
Q1.14.15	**Applicant**	Clarification. Paragraph 18.3.28 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] refers to the potential overlap following completion of Phase 1 construction where Phase 1 will be operational and Phase 2 in construction. This paragraph also states the worst-case scenario for construction and operation concurrently has been defined and assessed, resulting in Phase 1 being considered a more robust (worst-case) construction stage evaluation. This conclusion is drawn from the increased construction activity in Phase 1 compared to a combined assessment involving Phase 1 operational and Phase 2 construction. The operational stage worst case commences on completion of Phase 2. Can the applicant explain what data was used to evaluate the level of activity in the construction and operational stage and used to inform the assessment of worst-case scenario for construction and operation concurrently?	The level of activity for the construction phase is a minimum of 800 direct construction workers and a maximum of 1,300 direct construction workers and the length of the construction period is 5 years, from 2025 to 2030. The level of activity in the construction stage is based on the Applicant's experience and longstanding presence in the industry as well as similar consented and constructed industrial developments across the UK refer to the response to Q1.14.13 in this document. The level of activity for the operational phase is a minimum of 60 to a maximum of 130 direct operational jobs per annum and the length of the operational period of 25 years, from 2030 to 2055. The level of activity in the operation stage is an assumption from the Applicant based on the internal workings of the Proposed Development, knowledge of other chemical processing plants, understanding the minimum amount of time and staff that will be required for the plant to be operational 24/7 (as ES Chapter 4 [APP-056] Paragraph 4.3.8 notes) whilst complying with legal

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			working requirements and ensuring operation staffing can occur on a shift basis spread over a 24-hour period. As the focus in Phase 2 will solely be on the second phase of the Hydrogen Production Facility, it is expected that the construction workforce for that work will be significantly less than the 800 minimum considered in the overall assessment, likely less than 100. As such, those numbers, taken with the fact that the Phase 1 operational jobs will not be the maximum of 130 just for the Phase 1 operations, means that the numbers in that period will be less than the construction maximum assumed for the purposes of the socio-economic assessment.
Q1.14.16	**LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body**	Views sought. Do the LAs, together with any other relevant Authority/ Body, have any comments or observations in relation to the assessment of impacts and LSEs set out in 18.6 of ES Chapter 18 (Socio-economics and Land Use) [APP-071]?	n/a
Q1.14.17	**Applicant and LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body**	Clarification/ Additional information/ Views sought. Paragraph 18.6.11 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] indicates that based on the gross construction worker requirements in the construction schedule and the additionality factors outlined in previous paragraphs, it is estimated that 780 (net) construction jobs would be generated by the construction of the Proposed Development, of which around 585 are expected to be from the Middlesbrough and Stockton TTWA. Irrespective of this, the ExA has been unable to locate the 'requirement construction schedule' in this Chapter of the ES and is unclear as to what it is or how this has been assessed. Bearing this in mind, the ExA would ask: i. the Applicant to submit the 'requirement construction schedule' and advise how it has been assessed and/ or signpost where within the submitted Application documentation the 'requirement construction schedule', together with the explanation of how it has been assessed, can be located. ii. whether the LAs, together with any other relevant Authority/ Body, have any comments or observations on the Applicant's estimates relating to construction phase employment?	Paragraph 18.6.11 is referring to the number of gross construction workers required to facilitate the proposed construction schedule. This is not a separate document, the construction schedule being referred to is shown in Table 5-1 of Chapter 5: Construction Programme and Management [APP-057]. ES Chapter 18 (Socio-economics and Land Use) utilises the construction timeline and the expected number of gross construction jobs from the Applicant to inform the construction employment impacts. In particular, the assumptions used for the construction phase are outlined in Paragraph 18.3.24. Using this, the net construction employment is calculated in Section 18.6 using HCA Additionality guidance, leading to 780 net construction jobs. When considering that these net construction jobs are supported over the construction timeline of 5 years (2025 to 2030), and that net employment generated by the Proposed Development represents 5% of total employment in construction for the Middlesbrough and Stockton TTWA, this results in a Moderate Beneficial (Significant) effect. The effect of construction employment is then used as a basis for the assessment of effects on the local housing market and tourist accommodation in the construction phase. The assessment of this effect is considered from Paragraph 18.6.14 to 18.6.21. Overall, the effect is Minor Adverse (Not Significant).
Q1.14.18	**LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body**	Views sought. Paragraph 18.6.25 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] assesses the gross operational employment at a minimum level for both	n/a

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		Phases 1 and 2 to be 60 gross direct jobs. Do the LAs, together with any other relevant Authority/ Body, have any comments or observations on the Applicant's assessment? If so please fully explain your response.	
Q1.14.19	**LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body**	Views sought. Paragraph 18.7 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] sets out the Applicant's Essential Mitigation and Enhancement Measures. Do the LAs, together with any other relevant Authority/ Body, have any comments or observations they wish to make in regard to the mitigation and enhancement measures set out by the Applicant in this regard? If so please fully explain your response.	n/a
Q1.14.20	**Applicant and LAs (HBC, RCBC and STBC), together with any other relevant Authority/ Body**	Clarification/ Update/ Views sought. Paragraph 18.5.6 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] refers to the mitigation of "…the land loss associated with Cowpen Bewley Woodland Park, for sections of the pipeline…" with trenchless methods of construction being used to avoid the removal of any existing trees. The Applicant states "Therefore, there will be a line of trees between the railway and the AGI which are left intact throughout construction, providing some visual screening of the activities north of the railway." i. Can the Applicant please signpost where the impacts of this loss of land, significant or otherwise, has been assessed within the submitted Application documentation? ii. Please explain how the mitigation measures described in the above are to be secured through the draft DCO? Paragraph 18.5.10 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] states "The Applicant intends to mitigate the permanent loss of land at Cowpen Bewley Woodland Park with a replacement area of land that would be of at least the same size and standard as the land required by the project." It also indicates it will work with STBC to agree the layout and planting of this land. i. Can the Applicant and STBC provide an update on their discussions regarding layout and planting of the replacement area of land? ii. Can the Applicant explain how the process to agree and secure layout and planting with STBC will be secured (ie in the draft DCO [AS-013] or via another mechanism)?	The impacts of land take at Cowpen Bewley Woodland Park are discussed within Table 18-9 and Table 18-11 within ES Chapter 18: Socio-economics and Land Use [APP-071]. These tables detail the impacts within the construction and operational phase respectively, for Cowpen Bewley Woodland Park. The retention of the line of trees is included with the Outline LBMP (para 4.4.3), which will be delivered pursuant to Requirement 4 of the DCO. The commitment to the use of trenchless methods has been added to the Framework CEMP at Deadline 2. Approval by STBC of the layout (which would include planting, given the very nature of the type of replacement open space being provided) of the replacement open space land is secured through article 29 of the dDCO. Notwithstanding this mechanism being secured, the Applicant has begun discussions with STBC on what their layout requirements may be – a productive meeting has been held and the Applicant responded to follow up queries from STBC shortly before Deadline 2 to enable this to progress.
Q1.14.21	**Applicant**	Clarification. Paragraph 18.4.14 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] states that there are multiple footpaths that lie within the boundary of the Proposed Development Site and lists them. The footpaths are also shown in	i. The Applicant has undertaken extensive consultation with the Local Authorities on the Proposed Development.

EXQ1	QUESTION TO:	QUESTION:	APPLICANT'S RESPONSE
		Figure 3-1 (Environmental Constraints within 1 km of the Proposed Development Site) [APP-080], which shows all Public Rights of Way (PRoW) within 1 km of the Proposed Development Site. The following Paragraph (Paragraph 18.4.15) states that PRoW listed may be affected by the selected routes of the hydrogen pipelines and other connections. In addition, a number of other byways, bridleways and footpaths are listed in this and subsequent paragraphs. These include, but are not limited to: • Byway 30 (adjacent to the Proposed Development site, north of Wolviston Back Lane). • Bridleway 102/194/2 (located adjacent to the Proposed Development site in Grangetown). • Footpaths and bridleways that are also located to the north-east of the Proposed Development site, in Warrenby and Coatham. • Bridleways 116/32/1 and 116/36/1 (located closest to the Proposed Development site some 310m north-east). • Bridleways 116/32/1 and 116/33/1 (part of the England Coastal Path (Filey Brigg to Newport Bridge)). Please confirm: i. The level of consultation which has taken place with the LAs, with regards the PRoW referred to in this Chapter of the ES, which may be affected by the selected routes of the hydrogen pipelines and other connections? ii. How the potential closure of the PRoWs set out in Figure 3-1 (Environmental Constraints within 1 km of the Proposed Development Site) [APP-080] has been addressed in the draft DCO [AS-013] and whether it envisages the closure of these PRoW to be temporary or permanent? In addition to the above, the ExA notes Paragraph 18.4.16 of ES Chapter 18 (Socio-economics and Land Use) [APP-071] cites Paragraphs 102 and 104 of the National Planning Policy Framework (2023) as follows: *"access to a network of high-quality open spaces and opportunities for sport and physical activity is important for the health and well- being of communities"* (Paragraph 102) and *"decisions should protect and enhance public rights of way and access"* (Paragraph 104). Please: iii. signpost where the impacts and LSEs of the closure of PRoW have been assessed in ES Chapter 18 (Socio-economics and Land Use) [APP-071], including how they may be affected by the selected routes of the hydrogen pipelines and other connections? iv. explain how the Proposed Development accords with the National Planning Policy Framework 2023 in this regard?	During the pre-application stage the Applicant undertook two rounds of statutory consultation allowing local authorities, statutory bodies and local residents to raise any concerns about the proposals, to which no issues were raised about PRoW. Please refer to the Consultation Report [APP-030] for further details. Further to this, interested parties have submitted relevant representations on the Proposed Development on matters they wish clarified, to which the Applicant has responded at Deadline 1. The Applicant notes that (a) the relevant planning authorities have not raised PRoW matters as a concern in their RRs or LIRs and (b) no user group or individual user has raised concerns in relation to public rights of way. As noted in their SoCG submitted at Deadline 1, the Applicant will engage with UKHSA on these matters moving forward. ii. Requirement 5 of the dDCO requires a public right of way management plan to be approved by the relevant planning authority prior to temporarily diverting or closing any public right of way. Through this plan, impacts to users will be able to be mitigated. The Applicant does not seek to permanently close PRoWs and will not have the power in the DCO to able to do so. iii and iv. Chapter 18: Socio-economics and Land Use [APP-071] assesses the potential severance or closure impacts related to PRoWs and Open Space in the second row of tables 18-9 and 18-11. Following mitigation,.7 (such as to further limit the impact on PRoW users and access to Cowpen Bewley Woodland Park, the PRoW will not be closed concurrently, meaning a route into the Cowpen Bewley Woodland Park will always be available), there are no significant effects on PRoW and Open Space. The cumulative socio-economic effect of the scheme is assessed in Chapter 23: Cumulative Effects [APP-076]. No significant cumulative effects are identified for PRoW and Open Space. . In summary, the majority of impacts are temporary with minimal disruption to PRoW and Open Space, with the exception of the permanent loss of land at Cowpen Bewley Woodland Park. However, as noted in paragraph 18.7.1, *"The Applicant intends to mitigate the permanent loss of land at Cowpen Bewley Woodland Park with a replacement area of land that would be of at least the same standard as the land required by the project. The Applicant will work with Stockton-on-Tees*

EXQ1	QUESTION TO:	QUESTION:	APPLICANT'S RESPONSE
			Borough Council to agree the layout and planting of this land. This is secured through the DCO." This aligns with the National Planning Policy Framework guidance which states that *"Existing open space, sports and recreational buildings and land, including playing fields, should not be built on unless…the loss resulting from the proposed development would be replaced by equivalent or better provision in terms of quantity and quality in a suitable location"*, and this condition is met by the replacement land for Cowpen Bewley. The Proposed Development also ensures that the provision of PRoW remains the same as prior to the start of the construction phase, aligning with the National Planning Policy Framework on this measure. Collectively, this also means there are no significant effects on PRoW and Open Space across all phases of the Proposed Development.
Q1.14.22	**Applicant**	Clarification/ Additional Information sought. NE in its RR [RR-026] stated that further assessment of construction phase impacts to Best and Most Versatile (BMV) agricultural land is required to inform mitigation. It requests an agricultural land classification survey of the pipeline routes and areas of agricultural land proposed to temporarily or permanently lost, together with confirmation of the amount of BMV land by grade that would be lost, be supplied. Please supply the further assessment and surveys sought by NE, or signpost the ExA to where within the Application documentation the assessment and survey have been provided.	The Applicant would like to draw the Inspectorate's attention to the Applicant's Responses to Natural England's Relevant Representation Ref No. NE35 [REP1-007] for the Applicant's detailed position on this matter.
Q1.14.23	**Applicant**	Information Requested. ES Chapter 20 (Major Accidents and Disasters) [APP-073] states that risk assessments and revisions to the CEMP would be undertaken in respect of additional risk from major accidents and disasters associated with operation of Phase 1 simultaneously with construction of Phase 2. The ExA notes that there is currently limited information in the Framework CEMP [APP-043] in relation to this matter and no reference in Requirement 15 of the draft DCO [AS-013] to updating mitigation to suit the final phasing. The Applicant is requested to provide an outline of the anticipated risks and risk assessment process, together with confirmation as to how it is proposed to secure commitments to assessment and additional mitigation (if required).	A Final CEMP, produced prior to construction, will be produced prior to construction of Phase 2. This will be produced by the construction contractor and will set out how construction activities will be managed and controlled in compliance with accredited health and safety and environmental management systems, relevant legislation and environmental permits, consents and licenses. In addition to the Final CEMP, a Construction Phase Plan will be produced by the Principal Contractor under the CDM Regulations. Both the Final CEMP and the CPP will consider risks to workers and the wider environment from major accidents and disasters at the adjacent operational Phase 1 of the Proposed Development. Both documents will need to consider the offsite emergency management plans developed for Phase 1 (once operational) as part of the COMAH Safety Report.
Q1.14.24	**Applicant/ HSE**	Information requested/ views sought. The adopted Scoping Opinion [APP-185] requested an explanation of design guidance and criteria being followed for the hydrogen pipeline and how health and safety risks would be managed, noting that hydrogen is an emerging technology for which regulatory standards are likely to evolve.	At present, there is no hydrogen specific safety legislation, however in the absence of this there are a number of guidance documents developed to ensure industry complies with best practice and minimise risks to ALARP (See Appendix 5). These include codes of practice developed by the BCGA (British Compressed Gas Association) and research reports (RR) from the HSE. The BCGA have 2 notable codes of practice (CP), relevant to hydrogen, CP33 which outlines the bulk storage of gaseous hydrogen at user's

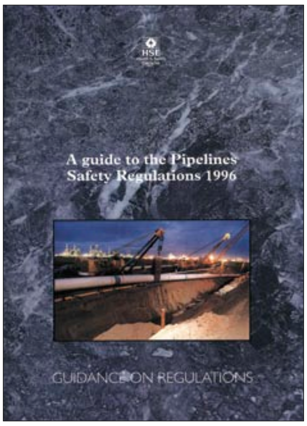
EXQ1	QUESTION TO:	QUESTION:	APPLICANT'S RESPONSE
		The Applicant in its Scoping Opinion Responses [APP-188] stated that this information is presented in ES Chapter 20 (Major Accidents and Disasters) [APP-073], where at section 20.2 it describes existing legislation, policy and guidance of relevance to the Proposed Development. However, there is limited reference to hydrogen specific information. **Can the Applicant provide confirmation of any hydrogen specific design guidance and criteria that are being followed for the Proposed Development, including any emerging guidance that may affect ongoing design development.** Can the HSE comment on the Applicant's approach to assessment of major accidents as set out in ES Chapter 20 (Major Accidents and Disasters) [APP-073] in the context of the Proposed Development comprising emerging hydrogen technology. Does the HSE consider that the Applicant has identified and assessed the potential risks associated with the hydrogen pipeline and production components?	premises, and CP52 which outlines the management of risks from gases in the workplace (Appendices 6 and 7). From the HSE, there are 2 relevant research reports, RR715 which outlines the installation permitting guidance for hydrogen and fuel cell stationary applications, and RR1169 which complements the guidance of RR715, with updated technical guidance on hydrogen viscosity and the potential leaks from hydrogen systems, with the report focussing on gas release and dispersion behaviour. (Appendices 8 and 9). Beyond these documents, the EA have prepared a technical review of emerging technologies for hydrogen production from methane and refinery fuel gas with carbon capture (Appendices 10 and 11). As noted in the Applicant's previous question responses above, the production of hydrogen from steam reforming methane has taken place for almost a century. In the absence of new emerging guidance, these existing guidance documents and design standards can be referenced. Ultimately, applicable design standards for the detailed design will be agreed in conjunction with the COMAH Competent Authority as part of the COMAH Safety Report.

APPENDIX 1: A GUIDE TO THE PIPELINES SAFETY REGULATIONS 1996

Health and Safety
Executive

A guide to the Pipelines Safety Regulations 1996

Guidance on Regulations



This is a free-to-download, web-friendly version of L82 (First edition, published 1996). This version has been adapted for online use from HSE's current printed version.

You can buy the book at www.hsebooks.co.uk and bookshops.

ISBN 978 0 7176 1182 9
Price £9.00

This booklet gives guidance on the Pipelines Safety Regulations 1996 which complement a number of other onshore and offshore regulations.

The Regulations apply to all pipelines in Great Britain and to all pipelines in territorial waters of the UK Continental Shelf, with a few exceptions that are also highlighted in the booklet.

It is aimed at helping operators and others involved with pipeline activities, or those who may be affected by the Regulations, what the Regulations require.

First published 1996
Reprinted 2002, 2004, 2011, 2012

ISBN 978 0 7176 1882 9

This guidance is issued by the Health and Safety Executive. Following the guidance is not compulsory and you are free to take other action. But if you do follow the guidance you will normally be doing enough to comply with the law. Health and safety inspectors seek to secure compliance with the law and may refer to this guidance as illustrating good practice.

Contents

Preface

This guide to the Pipelines Safety Regulations 1996 (SI 1996/825) is intended to help pipeline operators and others involved with pipeline activities or who may be affected by the Regulations to understand what the Regulations require.

Environmental considerations

The Pipelines Safety Regulations 1996, made under the Health and Safety at Work etc Act 1974, do not cover the environmental aspects of accidents arising from pipelines. However the Regulations, by ensuring that a pipeline is designed, constructed and operated safely, provide a means of securing pipeline integrity, thereby reducing risks to the environment.

It is important that effects on the environment are considered at all stages in the life cycle of a pipeline.

Most large onshore pipeline projects require an assessment to be carried out which is designed to identify the likely impact of a project on the environment, to determine the significance of that impact and to establish mechanisms which will minimise any adverse impact. The Electricity and Pipeline Works (Assessment of Environmental Effects) Regulations 1990 apply to cross-country pipelines as defined under the Pipelines Act 1962 (PA62) and detail the procedures to be followed when considering the need for an environmental statement to accompany an application for a pipeline construction authorisation from the Secretary of State for Trade and Industry. The Town and Country Planning (Assessment of Environmental Effects) Regulations 1988 apply to PA62 local pipelines.

The Environment Agency (or its Scottish equivalent the Scottish Environment Protection Agency) issues good practice guidance on how the operators' responsibilities under duty of care can best be met. The Water Resources Act 1991 gives the agencies powers of prosecution in the event of any spillages resulting in the pollution of watercourses.

Environmental aspects of offshore pipelines are addressed in the Pipelines Works Authorisations, issued by the Department of Trade and Industry, through the provisions of the Petroleum and Submarine Pipelines Act 1975.

For offshore pipelines with a diameter greater than 800 mm and a length of more than 40 km an environmental impact assessment will soon need to be carried out once the Environmental Impact Directive is implemented.

Information on design and construction

The Health and Safety Commission (HSC) has issued an informal discussion document to consider ways of ensuring that pipeline operators can comply with their duties through the provision of design and construction information.

Introduction

1 This booklet gives guidance on the Pipelines Safety Regulations 1996, which came into force on 11 April 1996. For convenience, the text of each regulation is included in *italics*, with the appropriate guidance immediately below. Where regulations are self-explanatory, no comment is offered.

2 The Pipelines Safety Regulations (referred to as 'the Regulations' in this guidance) replace earlier prescriptive legislation on the management of pipeline safety with a more integrated, goal-setting, risk-based approach encompassing both onshore and offshore pipelines. They revoke various requirements which had become unnecessary.

3 The Regulations complement other onshore and offshore regulations. Offshore they complement the new regime for offshore health and safety legislation at the heart of which lies the Offshore Installations (Safety Case) Regulations 1992 (SI 1992/2885). Onshore they complement the regulations dealing with extending competition to the domestic gas market including the Gas Safety (Management) Regulations 1996 (SI 1996/551). The Pipelines Safety Regulations cover:

(a) the definition of a pipeline;
(b) the general duties for all pipelines;
(c) the need for co-operation among pipeline operators;
(d) arrangements to prevent damage to pipelines;
(e) consequential amendments to other regulations (eg repeal of sections of the Pipelines Act 1962 and the revocation of three sets of regulations and parts of three further sets of regulations);

and for major accident hazard pipelines they cover:

(f) the description of a dangerous fluid;
(g) the requirement for emergency shut-down valves (ESDVs) at offshore installations;
(h) the notifications structure;
(i) the major accident prevention document;
(j) the arrangements for emergency plans;
(k) the transitional arrangements.

Scope of the Regulations

4 The Regulations apply to all pipelines in Great Britain, and to all pipelines in territorial waters and the UK Continental Shelf. Schedule 1 lists the pipelines to which these Regulations do not apply. Detailed guidance to Schedule 1 is given in the commentary on the Schedule.

Part I Introduction

Citation and commencement

Regulation

1

Regulation 1

These Regulations may be cited as the Pipelines Safety Regulations 1996 and shall come into force on 11th April 1996.

Interpretation

Regulation

2

Regulation 2

(1) *In these Regulations, unless the context otherwise requires -*

"dangerous fluid" has the meaning given by regulation 18(2);

Guidance

2

5 The definition of dangerous fluid in the Regulations is widely drawn; the fluids covered are contained in Schedule 2 which lists the dangerous fluids by generic category and, where appropriate, the conditions under which they are conveyed.

Regulation
2

"emergency shut-down valve" means a valve which is capable of adequately blocking the flow of fluid within the pipeline at the point at which it is incorporated;

Guidance

2

6 Regulation 19 requires emergency shut-down valves (ESDVs) to be fitted to certain pipelines connected to offshore installations. An ESDV should be capable of stopping the flow of fluid within the pipeline. However, minor internal leakage past the ESDV may be accepted providing it does not represent a threat to safety. The rate of leakage should be based on the installation's ability to control safely the hazards produced by such a leak.

Regulation

2

"the Executive" means the Health and Safety Executive;

"fluid" includes a mixture of fluids;

"local authority" means -

(a) *in relation to England, a county council, a council having the functions of a county council, the London Fire and Civil Defence Authority, a metropolitan county fire and civil defence authority, or the Council for the Isles of Scilly;*
(b) *in relation to Scotland, the council for a local government area; and*
(c) *in relation to Wales, a county council or a county borough council;*

Guidance

2

7 Regulations 25 and 26 relate to emergency plans to be prepared by local authorities. This duty falls to the local emergency planning authority; in the case of metropolitan authorities this rests with the appropriate metropolitan county fire and civil defence authority. In Scotland, where regional councils were replaced by unitary authorities on 1 April 1996, the preparation of emergency plans rests with the local unitary authority.

Regulation 2

"major accident" means death or serious injury involving a dangerous fluid;

Guidance 2

8 The term 'major accident' appears in a number of places in these Regulations. In particular, the judgement whether there is the potential to cause a major accident will determine the range of hazards identified, and the risks to be evaluated, under regulations 23(1)(a) and (b) and will determine the scope of emergency procedures and plans prepared under regulations 24 and 25.

9 A major accident would cover death or serious injury from a fire, explosion or uncontrolled emission from a pipeline. This includes both events which have escalated beyond the control of the normal operating envelope of the pipeline and those resulting from third party interference. Whether an event leads to serious danger to people will depend on factors specific to the incident. Major accidents to people can be distinguished from other accidents by the severity of the injuries, the number of casualties, or by the physical extent of the damage in areas where people may be present. The risk strategy needs to address fully the potential for any major accident.

Regulation 2

"major accident hazard pipeline" has the meaning given by regulation 18(1);

Guidance 2

10 A 'major accident hazard pipeline' is one which conveys a dangerous fluid which has the potential to cause a major accident.

Regulation 2

"operator", in relation to a pipeline means -

(a) the person who is to have or (once fluid is conveyed) has control over the conveyance of fluid in the pipeline;
(b) until that person is known (should there be a case where at a material time he is not yet known) the person who is to commission or (where commissioning has started) commissions the design and construction of the pipeline;
(c) when a pipeline is no longer, or is not for the time being used, the person last having control over the conveyance of fluid in it.

Guidance 2

11 The operator of the pipeline is the person who has control of the pipeline at any time during all stages of its life cycle from the design stage through to final decommissioning.

12 Until the person who is to have control of the conveyance of fluid is known, the operator is the person who commissions the design of the pipeline or (where such work has started) the person who commissioned the design.

Regulation 2

"pipeline" shall be construed in accordance with regulation 3.

(2) Unless the context otherwise requires, any reference in these Regulations to -

(a) a numbered regulation or Schedule is a reference to the regulation or Schedule in these Regulations so numbered; and
(b) a numbered paragraph is reference to the paragraph so numbered in the regulation or Schedule in which the reference appears.

Meaning of "pipeline"

Regulation

Regulation 3

(1) Subject to the provisions of this regulation, in these Regulations "pipeline" means a pipe or system of pipes (together with any apparatus and works, of a kind described in paragraph (2), associated with it) for the conveyance of any fluid, not being -

(a) a drain or sewer;
(b) a pipe or system of pipes constituting or comprised in apparatus for heating or cooling or for domestic purposes;
(c) a pipe (not being apparatus described in paragraph (2)(e)) which is used in the control or monitoring of any plant.

(2) The apparatus and works referred to in paragraph (1) are -

(a) any apparatus for inducing or facilitating the flow of any fluid through, or through a part of, the pipe or system;
(b) any apparatus for treating or cooling any fluid which is to flow through, or through part of, the pipe or system;
(c) valves, valve chambers and similar works which are annexed to, or incorporated in the course of, the pipe or system;
(d) apparatus for supplying energy for the operation of any such apparatus or works as are mentioned in the preceding sub-paragraphs;
(e) apparatus for the transmission of information for the operation of the pipe or system;
(f) apparatus for the cathodic protection of the pipe or system; and
(g) a structure used or to be used solely for the support of a part of the pipe or system.

3

Guidance

13 This regulation defines what is meant by a pipeline. Drains and sewers including liquid effluent outfalls which discharge into a river or estuary are not considered to be pipelines for the purposes of these Regulations.

14 These Regulations do not apply to pipelines which form part of control monitoring equipment such as small bore pipes or tubes normally bundled together with cables, wires, etc to form an 'umbilical' used for hydraulic control or signalling purposes.

15 However, new designs of 'umbilicals' are appearing with pipes within the bundle which are larger in diameter and are used for the conveyance of fluids for purposes other than control or monitoring. It is likely that future designs may include pipes of considerable diameter or even a number of 'large' diameter pipelines bundled together. Even though the basic design and structure of these new systems may be similar to umbilicals, they will be considered to be pipelines and will be subject to the requirements of these Regulations.

16 These Regulations cover pipelines used for the conveyance of fluid. Electrical equipment such as high voltage cable systems which utilise fluid under pressure for circuit integrity and are self-contained are excluded from the scope of these Regulations.

3

Regulation

3

(3) For the purpose of sub-paragraph (c) of paragraph (2) a valve, valve chamber or similar work shall be deemed to be annexed to, or incorporated in the course of, a pipe or system where it connects the pipe or system to plant, an offshore installation, or a well.

Guidance

3

17 Regulation 3(3) defines the interface between plant, an offshore installation or a well and the pipeline.

18 Figures 1 to 7 give examples of different interfaces and illustrate the limits of pipelines covered by these Regulations.

Note: The diagrams in Figures 1 to 7 are for illustrative purposes only - they are not proper representations of actual pipeline systems.

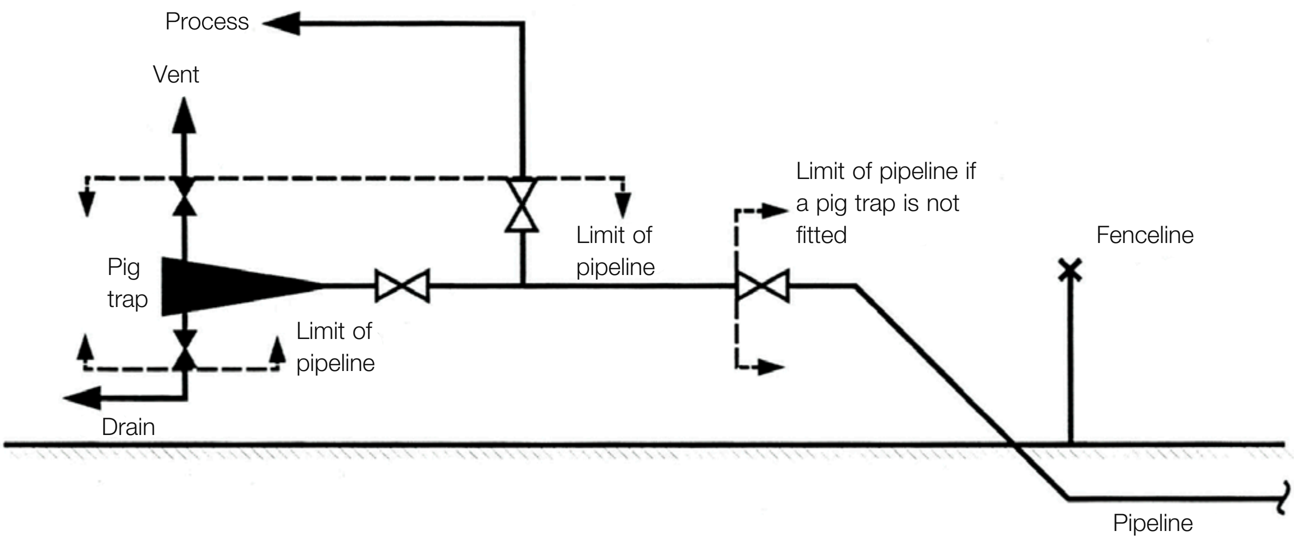


Figure 1 Limit of a pipeline at a factory, onshore terminal, refinery, etc

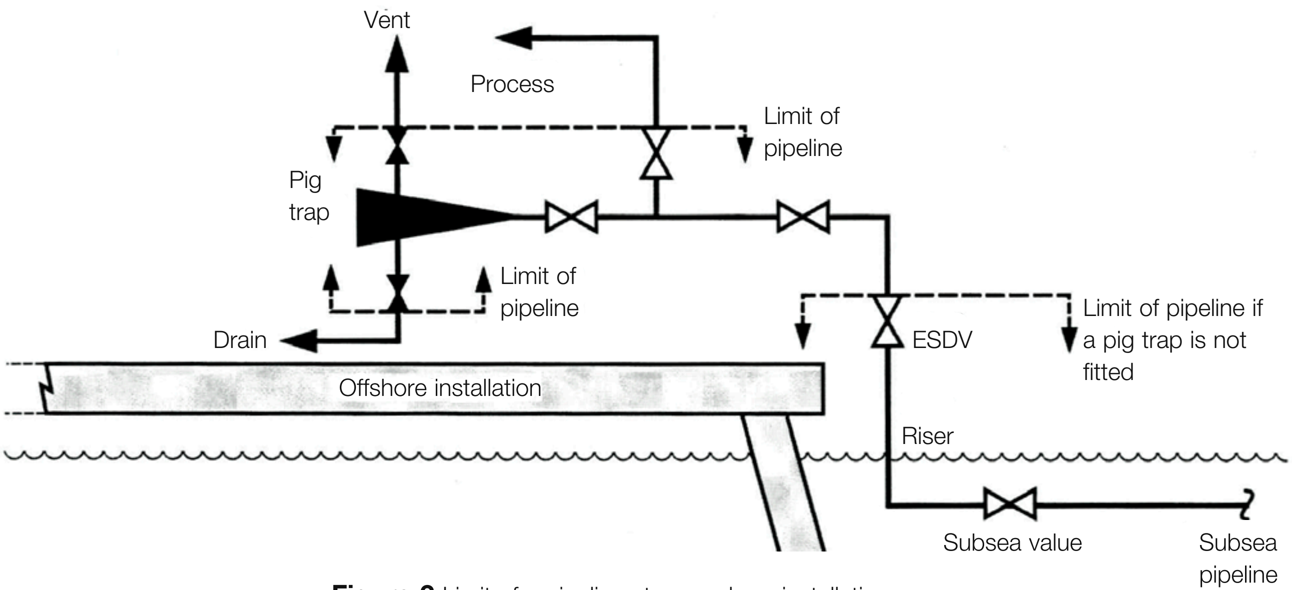


Figure 2 Limit of a pipeline at an onshore installation

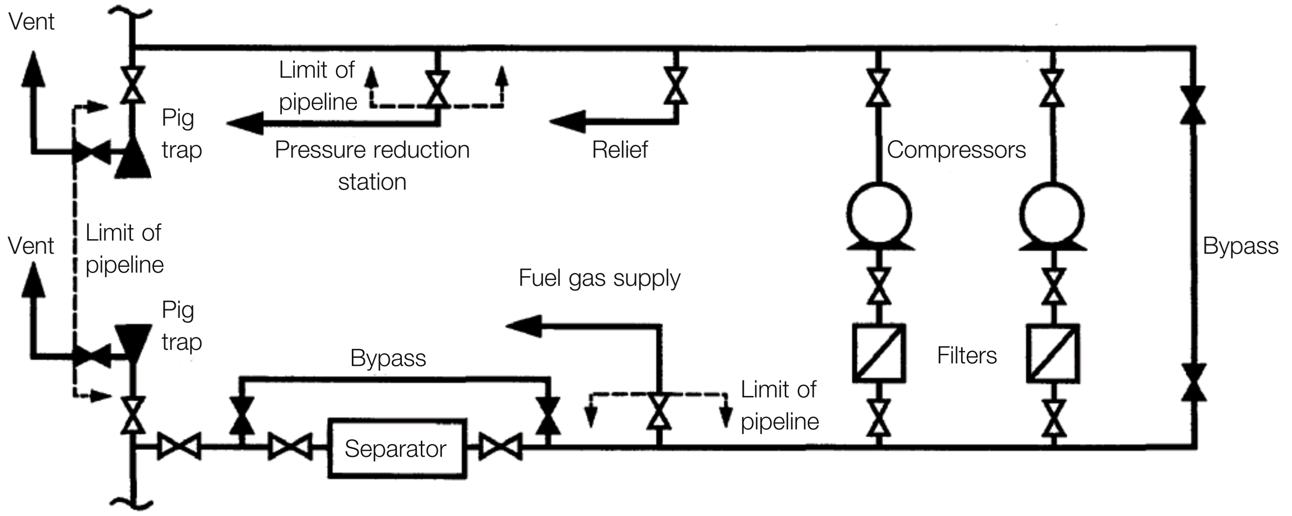


Figure 3 Limit of a pipeline at a mid-line gas compressor station

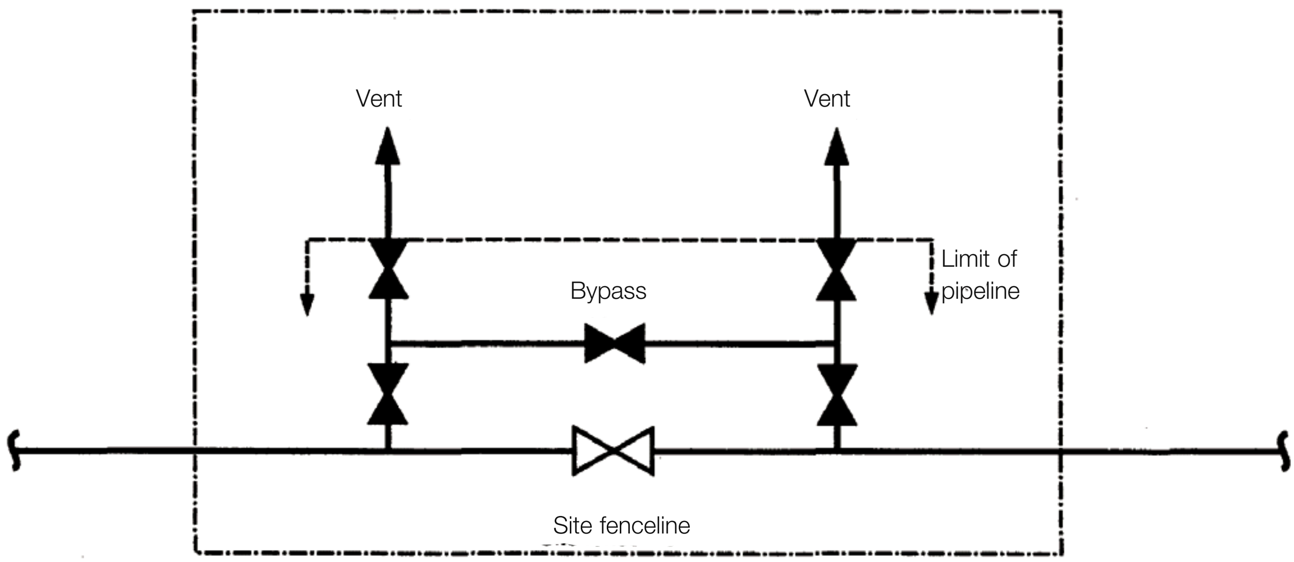


Figure 4 Limit of a pipeline at a block valve site

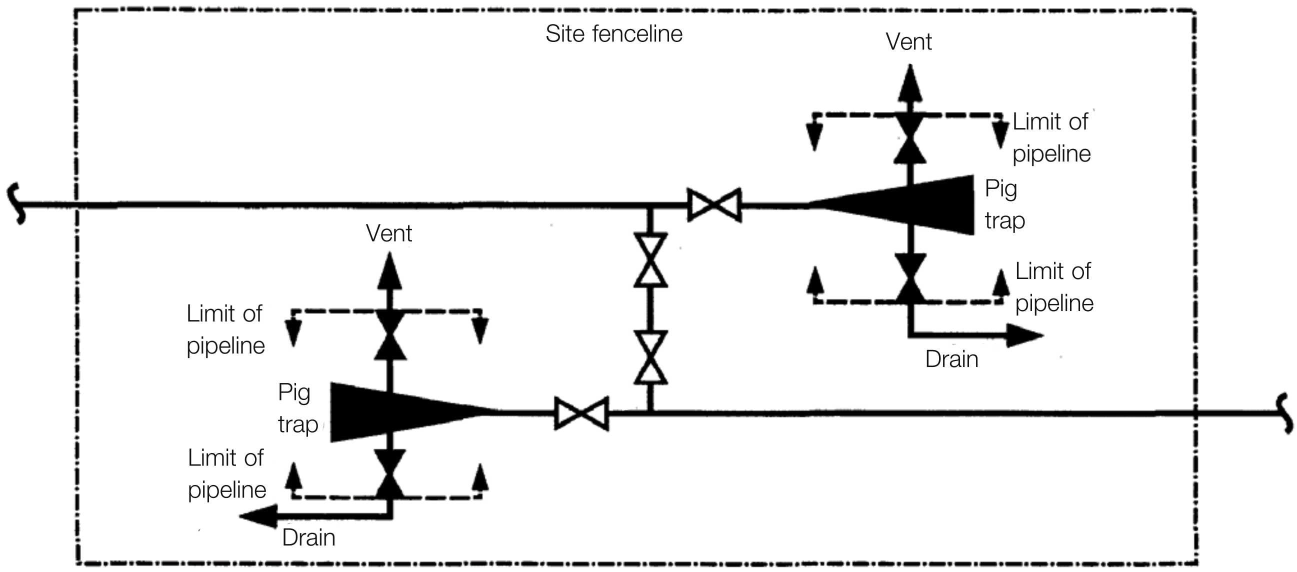


Figure 5 Limit of a pipeline at a mid-point pig trap site

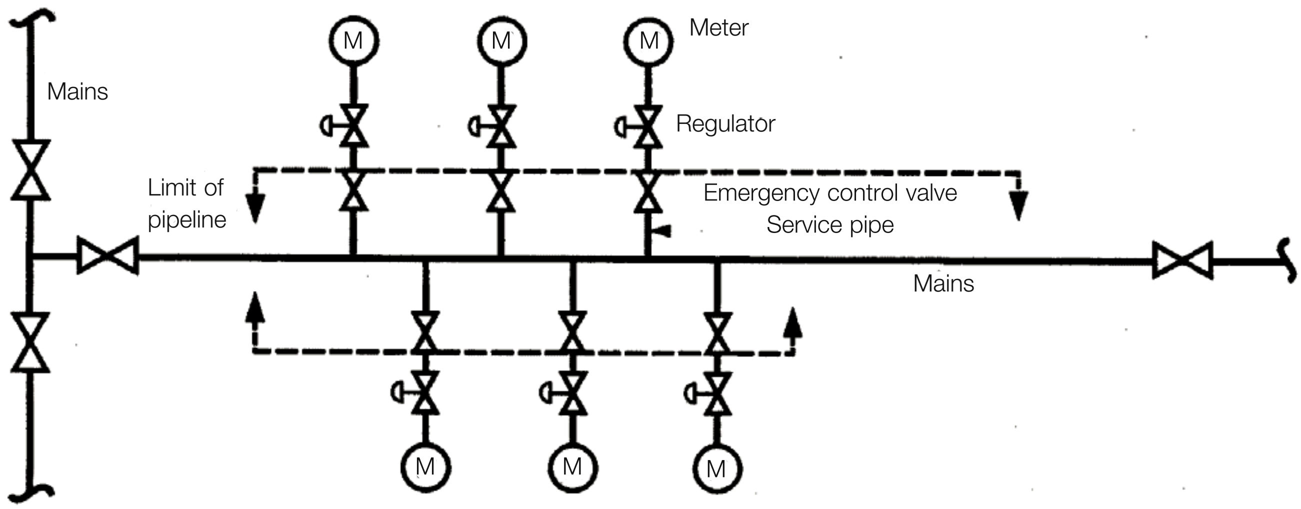


Figure 6 Limit of a pipeline for a gas distribution network

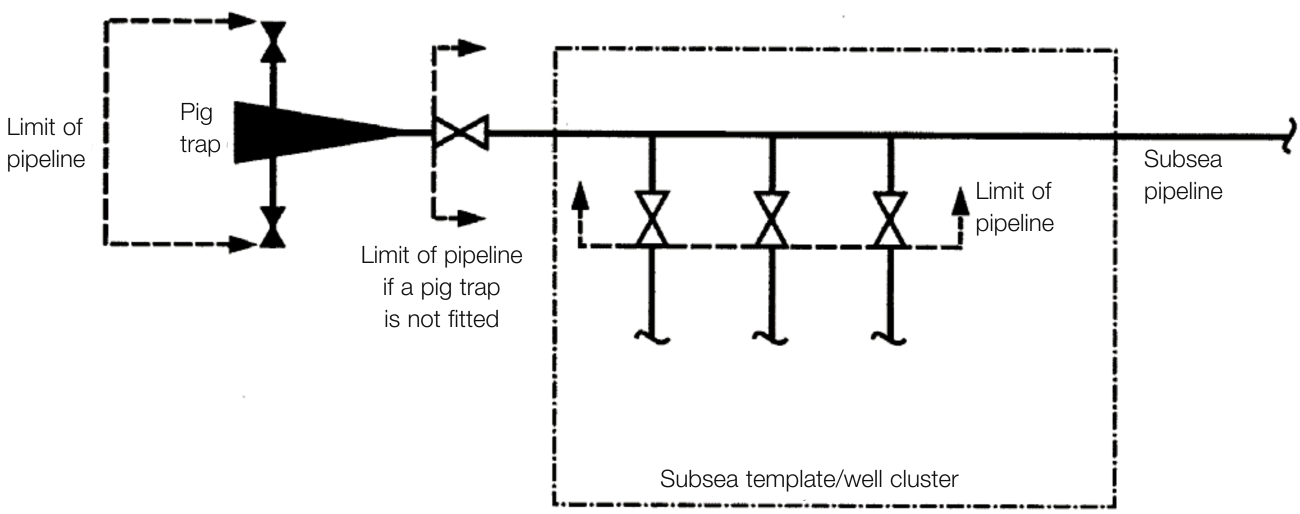


Figure 7 Limit of a pipeline at a subsea template or well cluster

Guidance

3

19 Pig traps connected to a pipeline, used for either launching or receiving pigs or for facilitating other equipment to be run through a pipeline, are included within the scope of the Regulations. The pig itself, or other equipment run through a pipeline, is not considered to be part of the pipeline.

20 For pipelines connected to onshore plant, the limit of the pipeline is the primary shut-off valve which connects the pipeline to the plant or the primary valve(s) off the pig trap, where fitted, which connects the pipeline to the plant. Process plant facilities and pipework beyond the primary shut-off valve are not covered by these Regulations.

21 On an offshore installation the limit of the pipeline is up to and including the emergency shut-down valve or primary shut-off valve(s) off the pig trap, where fitted, which connects the pipeline to the installation.

22 Although apparatus for inducing or facilitating flow is included in the definition of a pipeline, where such apparatus is not incorporated in the pipeline system itself, for example compressors on an offshore installation, then such apparatus is not covered by these Regulations.

Regulation

3

(4) A pipeline for supplying gas to premises shall be deemed not to include anything downstream of an emergency control.

(5) In this regulation -

"emergency control" means a valve for shutting off the supply of gas in an emergency, being a valve intended for use by a consumer of gas;

"gas" has the same meaning as it has in Part I of the Gas Act 1986[(a)].

(a) 1986 c. 44.

Guidance
3

23 For pipelines supplying gas as defined by the Gas Act 1986 to consumers, the limit of the pipeline in these Regulations is the emergency control.

Application

Regulation

Regulation 4

(1) Subject to paragraph (2), these Regulations shall apply -

(a) in Great Britain; and
(b) to and in relation to pipelines and activities outside Great Britain to which sections 1 to 59 and 80 to 82 of the 1974 Act apply by virtue of article 6 of the Health and Safety at Work etc. Act 1974 (Application outside Great Britain) Order 1995[(b)].

(2) These Regulations shall not apply to any pipeline or part of a pipeline which is described in Schedule 1.

4

(b) SI 1995/263.

Guidance

4

24 This regulation defines the scope of the requirements as pipelines in Great Britain, and all pipelines in territorial waters and the UK Continental Shelf. Schedule 1 lists the pipelines to which these Regulations do not apply. Detailed guidance to Schedule 1 is given in the commentary on the Schedule.

Regulation

(3) In the case of a pipeline to which the Pressure Systems and Transportable Gas Containers Regulations 1989[(a)] apply, nothing in these Regulations shall require the taking of any measures to the extent that they are for the prevention of danger within the meaning of those Regulations.

4

(a) SI 1989/2169.

Guidance

4

25 The Pressure Systems and Transportable Gas Container Regulations 1989 (PSTGCR) apply to onshore pipelines which constitute a ‘pressure system’ where the operating pressure is greater than 3 bar absolute (2 bar gauge) and conveying a relevant fluid. The regulations address in some detail pipeline hazards resulting from the stored energy of the fluid conveyed. Where measures are taken in compliance of PSTGCR to prevent danger within the meaning of those regulations, there will be no requirement for duplication of these measures through the Pipelines Safety Regulations.

Part II General

Design of a pipeline

Regulation

5

Regulation 5

The operator shall ensure that no fluid is conveyed in a pipeline unless it has been so designed that, so far as is reasonably practicable, it can withstand -

(a) forces arising from its operation;
(b) the fluids that may be conveyed in it; and
(c) the external forces and the chemical processes to which it may be subjected.

Guidance

5

26 The purpose of this regulation is to ensure that the design of a pipeline, or any modification to it, takes into account the operating regime for the pipeline, the conditions under which the fluid is to be conveyed as well as the environment to which the pipeline will be subjected.

27 The pipeline, or any modification to it, should be designed so that it is safe within the range of operating conditions to which it could be reasonably subjected. In the pipeline design, account should be taken of the maximum and minimum operating temperatures and of the maximum operating pressure of the pipeline. Account should also be taken of the nature of the fluid being conveyed, for example, corrosive, abrasive or chemical effects. The possibility of any subsequent changes in the fluid to be transported, or in the condition under which it is to be transported should be considered at the design stage.

28 The external forces and the chemical processes to which the pipeline will be subjected will need to be identified and evaluated. Account should be taken of the pipeline location and its susceptibility to damage. This may include consideration of the physical and chemical actions of the environment in which the pipeline is to be located and the terrain, subterrain or sea bed conditions. Account should be taken of foreseeable mechanical and thermal stresses and strains to which the pipeline may be subjected during its operation.

29 It is also important that the forces to which the pipeline is to be subjected during its construction are taken into account in its design.

30 Any change to the fluid conveyed will need a reassessment of the pipeline design to ensure that the pipeline is capable of conveying the fluid safely.

31 The design and location of the pipeline should take account of the hazard potential of the fluid being conveyed. Consideration should be given to routes which will minimise the possibility of external damage. Extra protection may be required to prevent damage from other conditions such as road and river crossings, long self-supported spans and structural movements.

32 In general, British Standards provide a sound basis for the design of pipelines. Other national or international standards (eg a relevant standard or code of practice of a national standards body or equivalent body of any member state of the European Union) are likely to be acceptable provided the proposed standard, code of practice, technical specification or procedure provides equivalent levels of safety.

Guidance

5

33 For low pressure natural gas polyethylene pipelines (operating below 8 bar absolute), technical guidance in the form of recommendations from the Institution of Gas Engineers offers standards recognised across the industry in IGE/TD 3: 1992 Edition 3: *Distribution mains* and IGE/TD 4: 1994 Edition 3: *Gas services*. The design of gas service pipelines is specifically addressed in the HSE Approved Code of Practice and guidance entitled *Design, construction and installation of gas service pipes* (ISBN 0 7176 1172 8).

Safety systems

Regulation

6

Regulation 6

The operator shall ensure that no fluid is conveyed in a pipeline unless it has been provided with such safety systems as are necessary for securing that, so far as is reasonably practicable, persons are protected from risk to their health or safety.

Guidance

6

34 The pipeline should be provided with such safety systems, as necessary, to protect people from risk. Safety systems cover means of protection such as emergency shut-down valves and shut-off valves which operate on demand or fail safe in the closed position, so minimising loss of containment of the pipeline inventory. Safety systems also include devices provided which prevent the safe operating limits being exceeded, for example pressure relief valves.

35 Safety systems are not meant to cover all control or measuring devices. However, safety systems do include control or monitoring equipment, such as flow detectors and pressure monitors, which have to function properly in order to protect the pipeline or to secure its safe operation.

36 Safety systems also include leak detection systems where they are provided to secure the safe operation of the pipeline. The method chosen for leak detection should be appropriate for the fluid conveyed and operating conditions.

37 Interlock arrangements may be provided as safety systems, particularly where they prevent inadvertent operation. For example, valve interlocks may be used in conjunction with bleed devices on pig trap door mechanisms to prevent opening up under pressure.

Access for examination and maintenance

Regulation

7

Regulation 7

The operator shall ensure that no fluid is conveyed in a pipeline unless it has been so designed that, so far as is reasonably practicable, it may be examined and work of maintenance may be carried out safely.

Guidance

7

38 The design of the pipeline should take due account of the need to facilitate examination and maintenance. Consideration should be given at the design stage to any requirement to provide suitable and safe access and operation for in-service inspections, such as pigging.

Materials

Regulation

8

Regulation 8

The operator shall ensure that no fluid is conveyed in a pipeline unless it is composed of materials which are suitable.

Guidance

39 This regulation requires that all materials of construction specified in the design of, and in any subsequent modifications to, the pipeline should be suitable for the intended purpose. This requirement applies not only to the pipeline but also to the associated equipment.

40 The material of construction should be able to withstand the physical and chemical conditions of the fluid to be conveyed under the operating conditions for which the pipeline has been designed. Any changes to the fluid conveyed or the operating conditions of the pipeline, including an extension of the pipeline design life, will warrant a reassessment of the pipeline material to ensure it is capable of conveying the fluid safely.

41 Changes in operating conditions include changes to the corrosion protection system which may well affect corrosion rates and therefore the design life of the pipeline.

8

Construction and installation

Regulation

9

Regulation 9

The operator shall ensure that no fluid is conveyed in a pipeline (save for the purpose of testing it) unless it has been so constructed and installed that, so far as is reasonably practicable, it is sound and fit for the purpose for which it has been designed.

Guidance

42 The purpose of this regulation is to ensure that a pipeline which has been properly designed, is fabricated, constructed and installed in a manner to reflect that design. During the installation, design considerations such as the location of the pipeline, depth of cover, need for supports or anchors, and extra protection at vulnerable locations should be adhered to.

43 Suitable procedures should be developed for the construction and installation of the pipeline. Pipe-laying techniques, appropriate to both the location of the pipeline and the type of pipeline being laid should be used.

44 The regulation recognises that before a pipeline is brought into operation it is common to allow the introduction of a fluid, commonly water, into the pipeline to pressure test as part of the demonstration of its soundness and fitness for purpose. Testing in this regulation includes precommissioning work such as pressure testing, flushing or cleaning the pipeline, or other activities which introduce fluids into the pipeline, prior to bringing it into use and the use of intelligent pigs in carrying out a baseline inspection.

9

Guidance

Relationship with other Regulations

Onshore Regulations

45 The Construction (Design and Management) Regulations 1994 (CDM) cover the health and safety management of construction projects by those who contribute to the avoidance, reduction and control of health and safety risks faced by construction workers, and others, when engaged on or affected by new construction works. CDM covers the design of the pipeline in so far as the design should take into account the safety of those carrying out the construction (and any subsequent) maintenance work. Similarly, CDM covers the safety management of those involved in the construction during the construction stage, but does not cover the design and construction of the pipeline for safe operation and use. This is covered by the Pipelines Safety Regulations 1996.

46 The CDM Regulations only apply to the actual construction work of a pipeline. Prefabrication work on a pipeline in a fabrication workshop or yard is outside the scope of CDM.

Offshore Regulations

47 Offshore pipelines and pipeline works are subject to the general provisions of the Health and Safety at Work etc Act 1974 (HSW Act) and HSW Act Regulations, such as the Management of Health and Safety at Work Regulations 1992 (MHSWR), which extend outside Great Britain.

48 This legislation is applied offshore by the Health and Safety at Work etc Act 1974 (Application outside Great Britain) Order 1995. The activities covered include: pipe-laying operations and associated work such as trenching; the inspection, testing, maintenance, repair, alteration or renewal of pipelines; and diving operations in connection with such works. MHSWR also extends to the connected activities of loading, unloading, fuelling or provisioning vessels engaged in pipeline works.

49 Employers of workers engaged in pipelines works or connected activities, for example on pipelay barges, are also required under regulation 15(2) of the Offshore Installations and Pipeline Works (Management and Administration) Regulations 1995 to ensure that their workers know or have ready access to the address and telephone number of the HSE office covering the sector in which the pipeline works are taking place.

50 Thus, all occupational risks connected with offshore pipeline construction works are subject to the HSW Act and the associated inspection and enforcement regime.

9

Work on a pipeline

Regulation

10

Regulation 10

The operator shall ensure that modification, maintenance or other work on a pipeline is carried out in such a way that its soundness and fitness for the purpose for which it has been designed will not be prejudiced.

Guidance

10

51 The purpose of this regulation is to ensure that any subsequent modification, maintenance or other work, such as inspection, of a pipeline should be carried out in such a way as not to affect detrimentally the pipeline's continuing fitness for purpose.

Operation of a pipeline

Regulation

11

Regulation 11

The operator shall ensure that -

(a) no fluid is conveyed in a pipeline unless the safe operating limits of the pipeline have been established; and
(b) a pipeline is not operated beyond its safe operating limits,

save for the purpose of testing it.

Guidance

11

52 In order to operate the pipeline in a safe manner, the operator will need to draw up safe operating limits, which reflect the pipeline design, its operating history and its current and future condition, and ensure that it is operated and controlled within these limits.

53 For pipelines, safe operating limits may be specified in terms of maximum operating pressure and maximum and minimum temperature. In some cases safe operating limits will also take into account such matters as fluid velocities and any limits set on the composition of the fluid.

54 The regulation recognises that for the purposes of proof testing a pipeline to ensure that it is sound and fit for purpose, it is often necessary to test the pipeline to pressures beyond its maximum allowable operating pressure, the safe operating limit.

Arrangements for incidents and emergencies

Regulation

12

Regulation 12

The operator shall ensure that no fluid is conveyed in a pipeline unless adequate arrangements have been made for dealing with -

(a) *an accidental loss of fluid from;*
(b) *discovery of a defect in or damage to; or*
(c) *other emergency affecting,*

the pipeline.

Guidance

12

55 This regulation requires that adequate arrangements are in place in the event of an incident or emergency relating to the pipeline. In particular arrangements should be in place for loss of containment and for discovery of damage to, or a defect in, the pipeline which requires immediate attention or action. The detail and scope of the arrangements will vary according to the type of pipeline, its location and the fluid being conveyed. Where a defect in, or damage to, a pipeline is found which could affect the safety of the pipeline, but not requiring immediate attention, then consideration will be needed of appropriate action in such circumstances.

56 In some circumstances it may be necessary for arrangements to be in place for emergencies which may have an affect on the pipeline. For example, arrangements should be in place covering an emergency on an offshore installation which may affect connected pipeline(s).

Relationship with other Regulations

Onshore Regulations

57 In the case of gas pipelines subject to the Gas Safety (Management) Regulations 1996, these arrangements for incidents and emergencies may be referred to in the gas transporter's or network emergency co-ordinator's safety case.

Offshore Regulations

58 Regulation 8 of the Offshore Installations (Prevention of Fire, Explosion and Emergency Response) Regulations 1995 requires the installation operator to draw up an emergency response plan for the installation and this should cover the arrangements in place for emergencies which may affect the connected pipeline.

Maintenance

Regulation

13

Regulation 13

The operator shall ensure that a pipeline is maintained in an efficient state, in efficient working order and in good repair.

Guidance

59 This regulation deals with the requirement to maintain the pipeline to secure its safe operation and to prevent loss of containment. Maintenance is essential to ensure that the pipeline remains in a safe condition and is fit for purpose.

60 The operator needs to consider maintenance and inspection requirements for the pipeline. Examination and monitoring of the pipeline are part of routine maintenance. The operator needs to consider both how and when the pipeline should be surveyed and examined to validate and maintain it in a safe condition.

61 The extent of the work done to maintain a pipeline will depend on its material of construction, its location, the fluid conveyed and the condition under which it is operated. For example, for low pressure gas distribution and service pipelines onshore, the operator should monitor the pipeline to secure its safe operation. For major accident hazard pipelines, the maintenance plan should form part of the pipeline's safety management system.

62 It is important to recognise that a pipeline includes associated equipment such as valves, bridles and other primary attachments. It may also include launch and reception pig traps. These should be maintained, as necessary, to ensure that they are kept in efficient working order. Maintenance under this regulation also includes maintaining any safety system associated with the pipeline which has been provided to secure its safe operation.

63 A pipeline which is out of service should also be maintained in a safe condition; if it has been out of service for a significant period of time, detailed assessment of the condition of the pipeline will be necessary to ensure fitness for purpose before returning it to service.

13

Decommissioning

Regulation

14

Regulation 14

(1) The operator shall ensure that a pipeline which has ceased to be used for the conveyance of any fluid is left in a safe condition.

Guidance

14

64 Pipelines should be decommissioned in a manner so as not to become a source of danger. Once a pipeline has come to the end of its useful life, it should be either dismantled and removed or left in a safe condition. Consideration should be given to the physical separation and isolation of the pipeline. It may be necessary to purge or clean the pipeline; due consideration should be given to the hazardous properties of any fluid conveyed in the pipeline or introduced during the decommissioning.

65 Depending on the physical dimensions of an onshore pipeline and its location, under the general provisions of the HSW Act, it may be necessary to consider the risk of the pipeline corroding and causing subsidence or acting as a channel for water or gases.

66 Offshore, pipelines should be either dismantled and removed or left in a condition where they will be not become a source of danger to people. It is likely that the riser section of an offshore pipeline will be dismantled. However, the extent of the obligation to remove the remainder of the pipeline will depend on the diameter of the pipeline, its location on the sea bed, its stability and on subsea conditions. It should be noted in this context that the decommissioning (in statutory language, abandonment) of offshore pipelines is also subject to and regulated by the Petroleum Act 1987 and should be discussed with the Department of Trade and Industry, whose formal approval for decommissioning programmes is required before they can be implemented.

Regulation
14

(2) The operator of pipeline shall ensure that work done in discharge of the duty contained in paragraph (1) is performed safely.

Guidance
14

67 Work done in carrying out the final decommissioning of a pipeline should be done in a safe and controlled manner.

Damage to pipeline

Regulation

15

Regulation 15

No person shall cause such damage to a pipeline as may give rise to a danger to persons.

Guidance

68 This regulation applies to the operator of the pipeline, for example when carrying out maintenance on the pipeline, to ensure that the pipeline does not sustain damage through his actions which could give rise to danger to people. Equally this regulation applies to the actions of third parties since interference is the main cause of damage to pipelines leading to loss of containment.

69 In many cases the damage to a pipeline by a third party is accidental; it is important that such damage is reported to the pipeline operator. Failure to notify damage to a pipeline which ultimately affects the safety of others could be a breach of the HSW Act. Some third party incidents may not appear to have caused obvious or serious damage, however, these incidents should still be reported to the pipeline operator as the pipeline may have been weakened or its integrity impaired in some other way, eg damage to its corrosion protection coating.

70 It is important that the location of onshore pipelines, and in particular underground pipelines, is considered when carrying out building, excavation or dumping or other such work, as such activities may either cause damage to pipelines or deny access to them for maintenance purposes.

71 Similarly, when carrying out vessel or anchoring activities offshore the location of offshore pipelines should be considered. Information regarding the location of offshore pipelines is normally available from the Hydrographer of the Navy and included on Admiralty charts.

15

Prevention of damage to pipelines

Regulation

16

Regulation 16

For the purpose of ensuring that no damage is caused to a pipeline, the operator shall take such steps to inform persons of its existence and whereabouts as are reasonable.

Guidance

72 It is important that third parties are made aware of the presence of a pipeline, and that information is available, where appropriate, regarding the location of the pipeline. For instance, where street work is to be undertaken information on the location of underground services including pipelines will be required. On request, pipeline operators should be able to give approximate locations of pipelines, usually in the form of plans.

16

Guidance

73 Because of the problems associated with identification of underground pipelines, parallel running of similar pipelines in the street should be avoided; where it is unavoidable, consideration should be given to means of identifying each pipeline such as with coloured plastic marker tape or indicator tape incorporating a metallic tracer wire. A colour coded identification system used by utilities and local authorities is set out in the National Joint Utilities Group publication No 4 *The identification of small buried mains and services* April 1995.

74 The operator shall take reasonable steps to inform people of the existence of the pipeline and its whereabouts, and for major accident hazard pipelines there should be regular contact with owners/occupiers and tenants of the land through which the pipeline passes. This should include supplying information on the route of the pipeline.

75 Depending on the fluid conveyed, the pipeline location and the conditions under which it is conveyed, it may be appropriate to consider periodic surveying of its route to check on activities which might affect the pipeline.

76 Offshore, damage to pipelines may arise from fishing activities and anchoring. Consideration should be given to reducing the potential for damage to offshore pipelines by use of concrete coating, trenching, burial, protection structures or mattresses etc.

Relationship with other Regulations

77 As part of the offshore Pipeline Works Authorisation issued by the Department of Trade and Industry under the Petroleum and Submarine Pipelines Act 1975, information regarding the location of offshore pipelines is normally passed to the Hydrographer of the Navy for inclusion on Admiralty charts.

16

Co-operation

Regulation

17

Regulation 17

Where there are different operators for different parts of a pipeline, each operator shall co-operate with the other so far as is necessary to enable the operators to comply with the requirements of these Regulations.

Guidance

78 This regulation places a duty on operators of different parts of a pipeline or a pipeline system to co-operate with other operators of that pipeline or system, where appropriate, to enable each of them to fulfil their duties under these Regulations. It does not mean that an operator of part of a pipeline can evade his own responsibilities by seeking to pass them to others. If an operator is capable of complying with a duty unaided, then the co-operation duty does not come into play. However, it is likely that where a pipeline or pipeline system has different operators for different parts of it, co-operation between each operator will be required in ensuring the health and safety of people or activities involving the pipeline.

17

Part III Major accident hazard pipelines

Dangerous fluids

Regulation

18

Regulation 18

(1) The provisions contained in regulations 19 to 27 shall apply in relation to a pipeline in which a dangerous fluid is being, or is to be conveyed (in these Regulations referred to as a "major accident hazard pipeline").

Guidance

18

79 This regulation defines the pipelines with the potential to cause a major hazard accident which attract the additional duties under these Regulations: emergency shut-down valves, notifications, the preparation of a major accident prevention document, the preparation of emergency procedures and the preparation of an emergency plan by the local authority.

Regulation
18

(2) For the purpose of these Regulations a fluid is a dangerous fluid if it falls within a description in Schedule 2.

Guidance

18

80 Dangerous fluids which are brought within these requirements are listed in Schedule 2. Detailed guidance about which fluids are described as dangerous is given in the commentary on the Schedule.

Emergency shut-down valves

Regulation

19

Regulation 19

(1) The operator of a major accident hazard pipeline which -

(a) is connected to an offshore installation; and
(b) has an internal diameter of 40 millimetres or more,

shall ensure that the requirements contained in Schedule 3 are complied with in relation to the pipeline.

Guidance

19

81 Emergency shut-down valves (ESDVs) are required to be fitted to all risers of major accident hazard pipelines of 40 mm or more in diameter at offshore installations. Schedule 3 sets out the requirements for these ESDVs.

Regulation

19

(2) The duty holder in relation to an offshore installation to which a pipeline described in paragraph (1) is connected shall afford, or cause to be afforded, to the operator of the pipeline such facilities as he may reasonably require for the purpose of securing that the requirements contained in Schedule 3 are complied with in relation to the pipeline.

(3) In this regulation -

"duty holder", in relation to an offshore installation, means the person who is the duty holder as defined by regulation 2(1) of the 1995 Regulations in relation to that installation.

Regulation

19

"the 1995 Regulations" means the Offshore Installations and Pipeline Works Management and Administration) Regulations 1995[(a)].

(a) SI 1995/738.

Guidance

19

82 This regulation places a duty on the duty holder in relation to the offshore installation to provide the operator of the pipeline with such facilities as he requires to fulfil his duties as set out in Schedule 3.

Notification before construction

Regulation

20

Regulation 20

The operator shall ensure that the construction of a major accident hazard pipeline is not commenced unless he has notified to the Executive the particulars specified in Schedule 4 at least 6 months, or such shorter lime as the Executive may approve, before such commencement.

Guidance

20

83 This regulation requires the operator to notify HSE of certain details of a proposed new pipeline prior to its construction. The intention is that this notification should be made at the 'end of the concept design' stage, which will normally be at least 6 months prior to the start of construction. The notification must contain the information contained in Schedule 4. This regulation only requires a notification to HSE; this does not place any constraint on the operator to proceed to detailed design and construction.

84 This notification may form the first contact between the pipeline operator and HSE; earlier contact may be helpful. This notification should be made at a point where the design is sufficiently advanced to be able to set out, in general terms, the particulars required in Schedule 4 but not so late that the company has already committed itself to major expenditure. Once a pipeline has been built, it is very difficult and extremely costly to make changes.

85 Only a limited amount of information about the pipeline is required at this notification stage. Where some of the information cannot, at the time of notification, be fully specified, notification to HSE should go ahead, together with details of when the further information may be provided, by agreement between the operator and HSE.

86 This notification is aimed at triggering HSE's inspection arrangements and it will provide the basis for the start of a dialogue between the pipeline operator and HSE about arrangements to secure the proper construction and safe operation of the pipeline. The intention behind the notification is to ensure that HSE is made aware of the proposed pipeline before major expenditure has been committed, since it is at this early stage that the most recent and best practice of design, and use of materials, can be applied at least cost. The information that is supplied will help HSE to form a view on appropriate inspection arrangements.

87 The information to be supplied need only represent the particulars as far as they have been developed by this stage. It is likely that there may be minor changes to the information, however, where the changes are significant to the level of risk of the pipeline, these further details should be supplied to HSE.

Guidance

88 Although for major projects, this notification will be made at an early stage and at least 6 months prior to the start of construction, there may be cases when a shorter notification period will be appropriate. HSE will be sympathetic to requests for shorter notification periods where good reason is demonstrated.

89 This may apply offshore to shorter lengths of pipeline or small projects, such as pipeline network extensions. There will also be cases which are a result of operational demands such as where there is a requirement to construct a pipeline from an installation for the purposes of well testing or evaluation. Cases when shorter notification is appropriate need the approval of HSE.

90 A reduced period of notification may be approved for short onshore pipelines, eg local pipelines to be built under section 2 of the Pipelines Act 1962, which may be viewed as relatively small projects where construction may be required to start over a shorter scale than six months.

91 Notification shall contain the details listed in Schedule 4. Notification should be sent to the appropriate office of HSE's Chemical and Hazardous Installations Division (CHID) in Aberdeen or Norwich (addresses below). As a general guide, pipelines located in Scotland or in Scottish waters are covered by the Aberdeen office, all other pipelines are covered by the Norwich office. Fax or other electronic transmission arrangements are acceptable.

Health and Safety Executive
Hazardous Installations Directorate
Lord Cullen House
Fraser Place
Aberdeen AB25 3UB
Tel: 01224 252500
Fax: 01224 252555

Health and Safety Executive
Hazardous Installations Directorate
Gas and Pipelines Unit
Rosebery Court, Central Avenue
St Andrews Business Park
Norwich
Norfolk NR7 0HS
Tel: 01603 275000
Fax: 01603 275055

Relationship with other Regulations

92 This notification does not form part of the role HSE undertakes as a consultee on the route of the pipeline for planning purposes. However, since HSE is consulted on, and assesses the route of, major accident hazard pipelines, both onshore and offshore, in practice the information required in the notification under this regulation will also be required for HSE to assess the route as a consultee.

Onshore pipelines

93 HSE is a consultee on the route of a land pipeline attracting the additional duties. The Department of Trade and Industry consults HSE on the route of cross-country pipelines and local planning authorities consult HSE on the route of local pipelines under the Pipelines Act 1962.

94 Through the licence condition of a public gas transporter under the Gas Act 1995, the route of high pressure gas pipelines need to be notified to HSE. In cases where the route does not comply with specific guidelines, HSE should be consulted on the proposed route.

Offshore pipelines

95 HSE is a consultee of the Department of Trade and Industry on the route of a proposed new pipeline under the Petroleum and Submarine Pipelines Act 1975.

Notification before use

Regulation

21

Regulation 21

The operator shall ensure that no fluid is conveyed in a major accident hazard pipeline, or conveyed following a period in which it has been out of commission (other than for routine maintenance), until the expiration of 14 days, or of such shorter period as the Executive may in that case approve, from the receipt by it of a notification of the date on which it is intended to convey, as the case may be, resume the conveyance of fluid in the pipeline.

Guidance

21

96 This notification, of the intention to bring the pipeline into use, is required so that HSE is made aware that the dangerous fluid is to be introduced into the pipeline.

97 A notification period of 14 days is required; though in exceptional circumstances a shorter notification period may be permissible if agreed by HSE.

98 This notification applies to the first introduction of the dangerous fluid into the pipeline. However, this regulation also applies to circumstances where the pipeline may have been taken out of commission (other than for routine maintenance, planned or emergency repair) and is to be brought back into use.

99 It is not intended that notification of bringing back into use will be required after it has been shut down for routine maintenance. Routine maintenance includes work such as valve lubrication, maintenance of pig traps, maintenance and replacement of cathodic protection equipment, function testing of pipeline equipment and instrumentation, running repair work (slight surface damage repairs, coating and wrapping repairs, rectification of spans etc). However, in cases where the pipeline has been subject to major modifications or remedial work which has been notified to HSE under regulation 22, notification of bringing back into use is required.

100 Notification can be made in writing, by fax or by telephone to the appropriate office of HSE's Chemical and Hazardous Installations Division (CHID) in Aberdeen or Norwich. Other electronic transmission arrangements are also acceptable. Information should include the pipeline identification, name of the operator/point of contact and date the pipeline is to be used for the first time or reused.

Notification in other cases

Regulation

22

Regulation 22

(1) Where there is a change of operator of a major accident hazard pipeline, or of his address, the operator shall notify any such change to the Executive within 14 days thereafter.

(2) Subject to paragraph (3), in the case of a major accident hazard pipeline the construction of which has commenced, or has been completed, the operator shall ensure that no event of a kind described in Schedule 5 takes place until the expiration of 3 months, or such shorter time as the Executive may in that case approve, from the receipt by the Executive of particulars specified in that Schedule in relation to such event.

(3) Where an event of a kind described in Schedule 5 takes place in an emergency, the operator shall notify to the Executive the particulars specified in that Schedule as soon as is reasonably practicable.

Guidance

22

101 This regulation concerns any significant changes to the pipeline which affect the level of risk. Notification to HSE is required of certain changes such as changes in the operating regime, major modifications to the pipeline, changes in fluid and cessation of use of the pipeline.

102 Schedule 5 sets out instances when notification is required; detailed guidance is given in the commentary to the Schedule.

103 The notification should be made to HSE at completion of the concept design for the change. The intention behind the 3-month notification period is to ensure that HSE is made aware of the proposed changes to a pipeline once the details have been established but before major expenditure has been committed. The information that is supplied will help HSE to form a view on appropriate inspection arrangements. However, urgent works may be carried out with shorter notification periods with the approval of HSE.

104 Notification of change of the pipeline operator, or his address, should be made within 14 days of the change being known.

105 Notification should be sent to the appropriate office of HSE's Chemical and Hazardous Installations Division (CHID) in Aberdeen or Norwich. Notification in writing, by fax or other electronic transmission arrangements is acceptable.

Major accident prevention document

Regulation

Regulation 23

(1) The operator shall, before the design of a major accident hazard pipeline is completed prepare, and thereafter revise or replace as often as may be appropriate, a document relating to the pipeline containing, subject to paragraph (2) sufficient particulars to demonstrate that -

(a) all hazards relating to the pipeline with the potential to cause a major accident have been identified;
(b) the risks arising from those hazards have been evaluated;
(c) the safety management system is adequate; and
(d) he has established adequate arrangements for audit and for the making of reports thereof.

(2) Paragraph (1) shall only require the particulars in the document referred to in paragraph (1) to demonstrate the matters referred to in that paragraph to the extent that it is reasonable to expect the operator to address them at the time the document is prepared or revised.

(3) Where the document referred to in paragraph (1) describes any health and safety arrangements or procedures to be followed, the operator shall ensure that those arrangements or procedures are followed unless in particular circumstances of the case it is not in the best interests of the health and safety of persons to follow them, and there has been insufficient time to revise or replace the document to take account of those circumstances.

(4) In this regulation -

"audit" means systematic assessment of the adequacy of the safety management system, carried out by persons who are sufficiently independent (if the system (but who may be employed by the operator) to ensure that such assessment is objective; and

"safety management system" means the organisation, arrangements and procedures established by the operator for ensuring that the risk of a major accident is as low as is reasonably practicable.

23

Guidance

106 This regulation deals with the operator's overall aims and principles of action for the control of the aspects of design, construction and installation, operation, maintenance and final decommissioning which have a bearing on the health and safety arrangements with respect to the control of major accident hazards.

107 The major accident prevention document (MAPD) initially shall be prepared during the design of the pipeline. Where there is a change in the fluid conveyed which results in an existing non-major accident hazard pipeline falling within the definition of a major accident hazard pipeline, then this will require a reassessment of the pipeline design. The MAPD should be prepared at this reassessment stage.

23

Guidance

Major accident prevention document

108 The MAPD is a management tool to ensure that the operator has assessed the risk from major accidents and has introduced an appropriate safety management system to control those risks. The aim is that the document will explain how the operator has established satisfactory management systems to control the major accident hazards of the pipeline or pipeline system.

109 The MAPD can be made up of a number of documents. A covering document may be prepared which need only be a short statement setting out the health and safety arrangements with respect to the control of the major accident hazards. This covering document should, however, refer to more detailed documents which make up the MAPD. These will include the safety management system detailing arrangements such as training procedures, management responsibilities and auditing arrangements which set down how that operator's policy to control major accident hazards will be put into action. It is important to recognise that safety management is an integral part of the normal business management of an organisation.

110 The MAPD should contain sufficient information to demonstrate that all hazards relating to the pipeline with the potential to cause a major accident have been identified and the risks arising from those hazards have been evaluated.

111 This requires the operator to identify the ways in which a major accident may occur and to evaluate the risks arising from those hazards. Account will need to be taken of hazards during the various stages of the life cycle of the pipeline including commissioning, excursions from normal operating limits, maintenance and any other activity which may affect the pipeline. This also requires consideration of matters such as the nature of the dangerous fluid being conveyed, the conditions under which it is conveyed and the susceptibility of the pipeline system to damage.

112 Where appropriate, an operator can produce a single MAPD for all his pipeline systems, rather than produce a separate MAPD for each individual pipeline. The MAPD must reflect the hazards and risks associated with all the major accident hazard pipelines covered by it and the supporting safety management system should be applicable to all those pipelines.

Safety management system

113 The pipeline MAPD should be supported by the safety management system which is in place for the control of the safety of the pipeline throughout its life cycle from its concept design through to decommissioning. The safety management system will need to consider the interfaces between the pipeline design, construction, operation and maintenance. Key elements of safety management are management's leadership, commitment and accountability. Both an adequate organisation and sufficient resources are necessary to implement the operator's policy with respect to the control of major accident hazards effectively.

114 It will be necessary for the MAPD, and the associated management arrangements, to be updated at various stages throughout the life cycle of the pipeline. It is recognised that, for example, at the concept design stage, it may not be practicable to describe future management procedures for controlling risks to people during the operation of the pipeline.

Guidance

115 A clear line of responsibility and accountability for the control of health and safety needs to be established from the highest management down. As a pipeline moves through the various stages of its life cycle, the line of command and accountability might change; the basis for change and arrangements for bringing it about should be set out in the safety management system.

116 The safety management system should cover the organisation and arrangements for preventing, controlling and mitigating the consequences of major accidents. These include specific attention to management competencies and procedures necessary to minimise the possibility of these events and if they occur, to limit their potential for causing harm. The safety management system is likely to set out the management control and monitoring procedures to be followed in critical areas such as:

- ensuring that systems are in place to provide for the satisfactory co-ordination of all those involved in the safety of the pipeline;
- establishment of operating procedures for normal operation of the pipeline as well as abnormal operation and non-routine operations;
- communication of those procedures to relevant personnel, eg through instructions, operating manuals, permits to work;
- establishment of adequate systems for the selection, control and monitoring the performance of contractors so that their working methods and standards are such as to ensure the safety of their activities;
- establishment of standards for training, for all people with a significant role to play in the safety of the pipeline. This is likely to extend to the highest levels of management and will also deal with training of those in supporting roles such as engineers and contractors;
- the procedures adopted for the systematic appraisal of the major accident hazards associated with the pipeline and evaluation of the risks arising from those hazards;
- procedures for the planning of modifications to be made to the pipeline.

117 The importance of the arrangements for achieving the initial and continuing safety of the pipeline requires that the safety management system pay particular attention to these arrangements. These include the arrangements for ensuring the soundness and fitness for purpose at the various stages in the life cycle of the pipeline.

118 It will be necessary that suitable and sufficient records of a pipeline are kept, including the design, construction, operation, and maintenance, so as to be able to demonstrate that the pipeline is safe.

119 Specific arrangements for dealing with emergencies form part of the safety management system. The emergencies to be addressed will result from the hazard identification and risk assessment process. Having identified all types of emergency events, plans and procedures should be prepared for dealing with these. The preparation of emergency procedures is covered in regulation 24.

23

Guidance

Audit

120 Once a systematic and formalised management approach to safety has been implemented, it becomes necessary to audit the system performance. This regulation requires that arrangements are in place for audits to be made of the safety management system which address its adequacy in achieving the safety of the pipeline. This requires a demonstration that there are clearly defined systems for audit of the quality of the design, construction, operation, maintenance and finally decommissioning of the pipeline. As for other aspects of the safety management system, performance standards for the audit and review process should be set and monitored. The people carrying out the audits should be sufficiently independent to ensure that such an audit is objective.

121 Auditing is referred to in HSE's publication *Successful health and safety management* as 'the structured process of collecting independent information on the efficiency, effectiveness and reliability of the total safety management system and drawing up plans for corrective action'.

122 In order to provide the necessary independent perspective and to maximise the benefits from the auditing process, audits should be carried out by competent people outside the line management chain of the areas or activities being audited.

123 Performance standards should be established to identify responsibilities, timings, and systems for reviewing. To ensure effectiveness, those responsible for implementing any remedial action should be clearly identified and deadlines set for the completion of such action. Audit should be viewed by all within the organisation as an opportunity to identify weaknesses in management control or procedures.

Relationship with other Regulations

Offshore Regulations

124 The definition in the Offshore Installations and Pipeline Works (Management and Administration) Regulations 1995 excludes pipelines, nevertheless there is a provision for any part of a pipeline connected to an installation and within 500 metres of the installation to be 'deemed' to be part of that installation, which is appropriate when considering the safety of people on the installation and possible consequences of a pipeline failure.

125 For the same reasons, offshore pipelines fall partly within the scope of the offshore safety case regime. Under Schedules 1 and 2 of the Offshore Installations (Safety Case) Regulations 1992 (SCR), the safety case must demonstrate that full account has been taken of risks to the installation, and to the people on it, arising from the pipeline. This entails, for any pipeline connected to an installation, giving a description of the design and hydrocarbon inventory of the pipeline demonstrating that an integrated approach will be taken to the management of the installation and the pipeline so risks from a major accident are at the lowest level that is reasonably practicable. The SCR provisions regarding pipelines at the interface are not enough in themselves to ensure the safe operation and integrity of offshore pipeline systems as a whole. However, work done in the safety case to identify the safety critical elements of a pipeline can be used in the pipeline MAPD.

23

Guidance

Onshore Regulations

126 The Gas Safety (Management) Regulations 1996 (GS(M)R) are concerned essentially with the safe management of the flow of gas through public gas transporters' networks. Those Regulations require a safety case to be prepared which should contain sufficient information to demonstrate that the transporter's operation is safe, and that the risks to the public and employees are as low as is reasonably practicable. Schedule 1 of those Regulations lists the particulars to be included in the safety case. It is not intended that the requirements of Schedule 1 of GS(M)R should duplicate those in the Pipelines Safety Regulations 1996 (PSR).

127 There are some areas of unavoidable overlap between these two sets of regulations, in particular the duties dealing with safety management systems (the MAPD in PSR and the safety case in GS(M)R). Although PSR covers safety management systems, such systems are concerned solely with pipeline integrity and the consequences of its loss. In contrast GS(M)R is concerned with the safe management of the supply of gas to users and the management of the flow of gas. To minimise duplication, those parts of any documents which are prepared under the requirements in PSR can be referenced in the GS(M)R safety case.

23

Emergency procedures

Regulation

Regulation 24

(1) The operator shall ensure that no fluid is conveyed in a major accident hazard pipeline unless -

(a) such appropriate organisation and arrangements as shall have effect; and
(b) the procedures which shall be followed in different circumstances,

in the event of an emergency relating to the pipeline have been established and recorded.

(2) The operator shall revise or replace the record of the organisation, arrangements and procedures referred to in paragraph (1) as often as may be appropriate.

(3) The operator shall ensure that the organisation, arrangements and procedures referred to in paragraph (1) are tested, by practice or otherwise, as often as may be appropriate.

24

Guidance

128 This regulation requires that adequate emergency procedures are prepared for dealing with the consequences of a major accident involving a pipeline. The detail and scope of a major accident will vary according to the pipeline, its location and the fluid conveyed and the operator will need to consider these aspects when drawing up the emergency procedures.

129 The emergency procedures for an offshore pipeline should cover the pipeline, as an entity, as well as the interface with offshore and onshore installations. The plan should cover the procedures needed to respond to all foreseeable major accidents involving a pipeline, ie it should set out who does what, when and how and to what effect, in the event of an emergency. It should describe arrangements at the interfaces with onshore and offshore installations to ensure that they dovetail.

24

Guidance

24

130 For onshore pipelines, it is important that the pipeline operator and local authorities liaise to ensure that the emergency procedures and the local authorities' emergency plans are dovetailed in order to provide a comprehensive and effective response to emergencies.

131 The emergency procedures should be kept in an up-to-date operational state. They should be revised as necessary to ensure that they cater for any changes in operation that might have a significant effect on the procedures.

132 Although this regulation does not specify the frequency at which tests should be carried out, it is important that the procedures are exercised and tested with sufficient frequency and depth so that they can be relied upon to work effectively in an emergency. The procedures should be monitored and reviewed in the light of exercises and tests and of any practical experiences gained from operating the plan in a real emergency, and remedial action identified and taken.

Relationship with other Regulations

Offshore Regulations

133 Regulation 8 of the Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations 1995 (PFEER) requires the owner or operator of an installation to prepare an emergency response plan for the installation after consulting with people likely to become involved in emergency response. Consultees will include the pipeline operator, operators and owners of other installations as necessary, for the plan to reflect agreement about shutting down pipelines for emergency response. The relevant parts of the pipeline emergency procedures required by the Pipelines Safety Regulations 1996 and the emergency response plan prepared through the requirement in PFEER should be compatible.

Emergency plans in case of major accidents

Regulation

25

Regulation 25

(1) A local authority which has been notified by the Executive that there is, or is to be a major accident hazard pipeline in its area shall before the pipeline is first used or within 9 months of such notification, whichever is later, and subject to paragraph (5), prepare an adequate plan detailing how an emergency relating to a possible major accident in its area will be dealt with.

(2) In preparing the plan pursuant to paragraph (1) a local authority shall consult the operator of the pipeline, the Executive and any other persons as appear to the authority to be appropriate.

(3) A local authority which has prepared a plan pursuant to paragraph (1) shall, as often as is appropriate and, in any case, at least every three years review the plan and make such revision as is appropriate.

Regulation

(4) The operator of a major accident hazard pipeline shall ensure that every local authority through whose area the pipeline will pass is furnished promptly with such information as it may reasonably require in preparing the plan referred to in paragraph (1).

(5) It shall be deemed to be sufficient compliance with the requirement in paragraph (1) as to the time by which a plan is to be prepared, where such time is exceeded by reason of waiting for information referred to in paragraph (4) which has been promptly required.

(6) Where a pipeline passes or is to pass through the areas of two or more local authorities the duties under this regulation may be discharged by them where they prepare a single plan.

25

Guidance

134 Local authorities at county or equivalent level, once notified of a pipeline by HSE, are required by this regulation to prepare an emergency plan for each major accident hazard pipeline passing through their area. The requirement under these Regulations is for emergency plans which should specifically relate to the protection of the health and safety of people, not environmental damage.

135 Though local authorities will already have general emergency plans, it will be necessary to have either pipeline specific plans or to include specific reference to each major accident pipeline and how their emergency arrangements are integrated into the existing emergency provisions in the area covered by the authority.

136 It is intended that emergency plans should only be drawn up or amended after consultation with bodies who may be able to contribute information or advice. In all cases this will include the emergency services (fire, police and ambulance), hospitals, the pipeline operators and HSE. Other bodies to be consulted will depend on circumstances and could include adjacent local authorities through whose area the pipeline passes, government departments dealing with agriculture, the Environment Agency or its Scottish equivalent, the Scottish Environment Protection Agency, and companies providing water services.

137 Full liaison and effective two-way flow of information is required between the pipeline operator and the local authority. Information from the pipeline operator is needed to enable the authority to draw up the emergency plan, and information from the authority should be available to the pipeline operator to assist in the preparation of the pipeline emergency procedures so as to achieve dovetailing between the pipeline emergency procedures and the local authority's emergency plan.

138 The pipeline operator should provide information about the type and consequences of possible major accidents and the likely effects. Information should also be provided on the route of the pipeline, the fluid conveyed and the operating conditions, location of shut-off valves and emergency control arrangements.

139 In the event of an incident involving a pipeline, it is important there is effective communication between the emergency services and pipeline control centre.

25

Guidance

140 The emergency plan should be a written document, in a format which can be used readily in emergencies, and kept up to date to reflect changes in risk, procedures, hardware and personnel. The authors of the plan must address all relevant aspects including the following:

(a) the types of accidents to people to be taken into account;
(b) organisations involved including key personnel and responsibilities and liaison arrangements between them;
(c) communication links including telephones, radios and standby methods;
(d) special equipment including fire-fighting materials, damage control and repair items;
(e) technical information such as chemical and physical characteristics and dangers of the fluid conveyed;
(f) information about the pipeline including route of the pipeline, location of shut-off valves and emergency control arrangements;
(g) evacuation arrangements;
(h) contacts and arrangements for obtaining further advice and assistance, eg meteorological information, transport, first aid and hospital services, water and agricultural information;
(i) arrangements for dealing with the press and other media interests.

141 Since an incident involving a pipeline could occur at any point along its length, it is often inappropriate to provide location specific advice along the whole length of the pipeline. The plan is likely to focus on those parts of the pipeline which are vulnerable to damage such as road, rail and river crossings and other areas of higher risk. Pipeline plans for this reason are likely to be generic and flexible in nature.

142 In discharging their duties, local authorities must take reasonable steps to ensure that they are preparing plans which will prove adequate in the event of major accidents. This will involve checking and testing the various components of each plan during its development.

143 The local authority shall review, and where necessary, revise and update the plan at suitable intervals so that it can be relied upon to work effectively in an emergency. The maximum interval for review should be every three years.

144 For existing pipelines, local authorities are allowed 18 months from notification of the pipeline to prepare the major accident hazard emergency plans (see regulation 27(6)).

145 For all new pipelines, the plan is required before the pipeline is brought into use, or within 9 months of notification of the pipeline to the local authority by HSE, whichever is the later.

Charge by a local authority for a plan

Regulation

Regulation 26

(1) A local authority which prepares, reviews or revises a plan pursuant to paragraph (1) or (3) of regulation 25 may charge a fee, determined in accordance with paragraphs (2) to (4), to the operator of the pipeline to which the plan relates.

(2) A fee shall not exceed the sum of the costs reasonably incurred by the local authority in preparing, reviewing or revising the plan and, where the plan covers pipelines of which there are more than one operator, the fee charged to each operator shall not exceed the proportion of such sum attributable to the part or parts of the plan relating to his pipelines.

(3) In determining the fee no account shall be taken of costs other than the costs of discharging functions in relation to those parts of the plan which relate to the protection of health or safety of persons and which were costs incurred after the coming into force of these Regulations.

(4) The local authority may determine the cost of employing a graded officer for any period on work appropriate to his grade by reference to the average cost to it of employing officers of his grade for that period.

(5) When requiring payment the local authority shall send or give to the operator of the pipeline a detailed statement of the work done and costs incurred including the date of any visit to any place and the period to 'which the statement relates; and the fee, which shall be recoverable only as a civil debt, shall become payable one month after the statement has been sent or given.

26

Guidance

146 This regulation enables the local authorities who are responsible for preparing and keeping up-to-date emergency plans required under regulation 25 to recover the cost of undertaking this work from the pipeline operator.

147 The local authority may only recover costs that have been reasonably incurred. There may be locations where several pipelines are co-located, so the local authority may decide to prepare one emergency plan covering all the pipelines. In such an event each pipeline operator should be charged for only that part of the costs which can be attributed to the pipeline under his control.

148 The charge made may only be for the cost of preparing the plan itself and of any changes necessary to keep it up to date. It does not cover the cost of emergency equipment (eg fire appliances) considered necessary for the operation of the plan. Furthermore, the charge should relate only to those parts of the emergency plan concerned with the health and safety of people, not with environmental damage.

149 The charge made may be based on the time spent by officers of appropriate grades. The average costs of their employment overheads as well as salary may be taken into account.

26

Guidance

26

150 In presenting a charge to a pipeline operator, the local authority should provide an itemised, detailed statement of work done and cost incurred. Any dispute arising over the charge has to be decided in the civil courts. HSE has no enforcement role for the recovery of cost incurred by a local authority in respect of emergency planning.

Transitional provision

Regulation

27

Regulation 27

(1) In the case of a pipeline, the construction of which is commenced within 6 months after the coming into force of these Regulations, it shall be sufficient compliance with regulation 20 If the particulars specified in Schedule 4 are notified to the Executive within 3 months after the coming into force of these Regulations.

Guidance

27

151 For major accident hazard pipelines where the construction is commenced within 6 months of these Regulations coming into force, the information required in regulation 20 and Schedule 4 should be notified to HSE within 3 months.

Regulation

27

(2) Subject to paragraph (3), in the case of a major accident hazard pipeline, the construction of which was commenced (and whether or not completed) before the coming into force (if these Regulations the particulars specified in Schedule 4 (or, in the case of paragraphs 3, 4, 5, 6 and 8 particulars, where appropriate, of the actual route of the pipeline or of the riser, materials used, fluid conveyed, and the temperature and pressure, and maximum rate of flow of that fluid) shall be notified to the Executive within 6 months after such coming into force.

(3) Paragraph (2) shall have effect where, pursuant to regulation 3(1) of the Notification of Installations Handling Hazardous Substances Regulations 1982[a], the particulars relating to that pipeline specified in Part II of Schedule 2 to those Regulations have been supplied before such coming into force.

(a) SI 1982/1357

Guidance

27

152 For existing major accident hazard pipelines, or ones under construction, the information required by regulation 18 of Schedule 4 should be notified to HSE within 6 months of the Regulations coming into force, unless the pipeline has been notified to HSE through the notification requirement in the Notification of Installations Handling Hazardous Substances Regulations 1982.

Regulation

27

(4) In the case of a pipeline, the design of which was completed before the coming into force of these Regulations, or within 12 months after such coming into force, regulation 23 shall have effect as if, for the words "before the design of a major accident hazard pipeline is completed" in paragraph (1) of that regulation there were substituted the words "within 12 months after the coming into force of these Regulations".

Guidance

27

153 Where a major accident prevention document (regulation 23) is required for existing major accident hazard pipelines and for proposed new pipelines, where the concept design will be completed within 12 months of the Regulations coming into force, the MAPD should be in place by 11 April 1997.

Regulation

27

(5) In the case of a pipeline which was first used before the coming into force of these Regulations it shall be sufficient compliance with the requirement in regulation 24(1) where the matters referred to therein are recorded within 6 months after the coming into force of these Regulations.

Guidance
27

154 For existing major accident hazard pipelines, the emergency procedures should be in place within 6 months of the Regulations coming into force.

Regulation

27

(6) Where a local authority receives a notification referred to in paragraph (1) of regulation 25 within 6 months after the coming into force of these Regulations, that regulation shall have effect in relation to the pipeline notified as If the reference in that paragraph to 9 months were a reference to 18 months.

Guidance
27

155 For existing pipelines a local authority, once notified of a major accident hazard pipeline, is allowed 18 months to prepare its emergency plan.

Part IV Miscellaneous

Defence

Regulation

Regulation 28

(1) In any proceedings for an offence for a contravention of any of the provisions of these Regulations it shall, subject to paragraphs (2) and (3), be a defence for the person charged to prove -

(a) that the commission of the offence was due to the act or default of another person not being one of his employees (hereinafter called "the other person"); and
(b) that he took all reasonable precautions and exercised all due diligence to avoid the commission of the offence.

(2) The person charged shall not, without leave of the court, be entitled to rely on the defence in paragraph (1) unless, within a period ending seven clear days -

(a) before the hearing to determine mode of trial, where the proceedings are in England or Wales; or
(b) before the trial, where the proceedings are in Scotland,

he has served on the prosecutor a notice in writing giving such information identifying or assisting in the identification of the other person as was then in his possession.

(3) For the purpose of enabling the other person to be charged with and convicted of the offence by virtue of section 36 of the 1974 Act, a person who establishes a defence under this regulation shall nevertheless be treated for the purposes of that section as having committed the offence.

28

Guidance

28

156 It shall be the operator's responsibility to ensure that any other person contracted to perform work does what is required in helping to meet the legal obligation set by these Regulations. The operator will therefore need to put in place suitable arrangements to ensure proper performance of functions required under these Regulations. Regulation 28(1) offers a defence in legal proceedings, if it can be shown that a contravention of the Regulations is due to an act or default of another person and the operator exercised all due diligence. It should be noted that where the commission of an offence is due to the act or default of another person, HSE has powers, through section 36 of the Health and Safety at Work etc Act 1974 (HSW Act), to prosecute the other person.

Certificates of exemption

Regulation

29

Regulation 29

(1) Subject to paragraph (2) and to any of the provisions imposed by the Communities in respect of the encouragement of improvements in the safety and health of workers at work, the Executive may, by a certificate in writing, exempt any person, pipeline or class of persons or pipelines from any requirement or prohibition imposed by these Regulations and any such exemption may be granted subject to conditions and with or without limit of time and may be revoked by a certificate in writing at any time.

(2) The Executive shall not grant any such exemption unless, having regard to the circumstances of the case and, in particular, to -

(a) the conditions, if any, which it proposes to attach to the exemption; and
(b) any other requirements imposed by or under any enactments which apply to the case,

it is satisfied that the health and safety of persons who are likely to be affected by the exemption will not be prejudiced in consequence of it.

Repeal of provisions of the Pipe-lines Act 1962

Regulation

30

Regulation 30

Sections 20 to 26, 27 to 32 and 42 of the Pipe-lines Act 1962 are hereby repealed.

(a) 1962 c.58; section 24 was repealed by SI 1974/1986; and section 26A was inserted by section 26 of the Petroleum Act 1987 (1987 c.12).

Guidance

30

157 This regulation sets out the sections of the Pipelines Act 1962 (PA62) which are repealed by these Regulations. These sections are relevant statutory provisions of the HSW Act. Safety notices served by HSE under PA62 do not apply after these Regulations come into force.

158 Section 37 of PA62 which requires notifications of certain pipeline accidents to the emergency services etc. is not being repealed by these regulations since this section covers notifications which may include environmental effects such as pollution of water.

Revocation and modification of instruments

Regulation

31

Regulation 31

(1) The instruments specified in column 1 of Part I of Schedule 6 shall be revoked to the extent specified in column 3 of that Part.

(2) The Notification of Installations Handling Hazardous Substances Regulations ("the 1982 Regulations") shall have effect subject to the modifications of those Regulations specified in Part II of Schedule 6.

Guidance

31

159 This regulation sets out the revocations and modification of statutory instruments associated with these Regulations and also listed in Schedule 6.

160 The Notification of Installations Handling Hazardous Substances Regulations 1982 have been modified to remove the requirement to notify certain pipelines to HSE contained in those Regulations.

Pipelines to which these Regulations do not apply

Schedule

Schedule 1

Regulation 4(2)

1 A pipeline for the conveyance of air, water vapour or steam.

2 A pipeline for the conveyance of water, other than for the purpose of injecting water into an underwater well or reservoir containing mineral resources.

3 A pipeline contained wholly within the premises occupied by a single undertaking.

4 A pipeline which is contained wholly within land which constitutes a railway asset within the meaning of section 6(2) of the Railways Act 1993[a].

5 A pipeline contained wholly within a caravan site.

6 In this Schedule "caravan" and "caravan site" have the same meaning as they have in Part I of the Caravan Sites and Control of Development Act 1960[b].

1

(a) 1993 c. 43.
(b) 1960 c. 62; the meaning of "caravan" in Part I was modified by the Caravan Sites Act 1968 (c.52), section 13(1) and (2).

Guidance

161 This Schedule sets out pipelines to which the Regulations do not apply. Pipelines wholly within premises are excluded from the scope of these Regulations.

162 These Regulations do not apply to pipelines contained wholly within caravan sites. In general the pipelines excluded by this paragraph will be LPG gas pipelines which convey gas from a gas tank situated in the caravan site to caravans on the site.

163 Pipelines used as part of the railway infrastructure are also excluded from the scope of these Regulations. However, this exclusion only applies to pipelines used as part of the railway infrastructure; other pipelines on railway land, not forming part of the railway infrastructure, come within the scope of these Regulations.

164 Pipelines which convey water are excluded from the scope of these Regulations except offshore where they convey water for high pressure water injection purposes.

Schedule 1

Descriptions of dangerous fluids

Schedule

Schedule 2

Regulations 18(2) and 27(3)

1 A fluid which -

(a) is flammable in air;
(b) has a boiling point below 5°C, at 1 bar absolute; and
(c) is or is to be conveyed in the pipeline as a liquid.

2 A fluid which is flammable in air and is or is to be conveyed in the pipeline as a gas at above 8 bar absolute.

3 A liquid which has a vapour pressure greater than 1.5 bar absolute when in equilibrium with its vapour at either the actual temperature of the liquid or at 20°C.

4 A toxic or very toxic fluid which -

(a) is a gas at 20°C and 1 bar absolute; and
(b) is, or is to be, conveyed as a liquid or a gas.

5 A toxic fluid which -

(a) at 20°C has a saturated vapour pressure greater than 0.4 bar; and
(b) is, or is to be, conveyed in the pipeline as a liquid.

6 Acrylonitrile.

7 A very toxic fluid which -

(a) at 20°C has a saturated vapour pressure greater than 0.001 bar; or
(b) is, or is to be, conveyed in the pipeline as a liquid at a pressure greater than 4.5 bar absolute.

8 An oxidising fluid which is, or is to be, conveyed as a liquid.

9 A fluid which reacts violently with water.

10 For the purposes of this Schedule -

(a) a liquid is oxidising; and
(b) a fluid is toxic or very toxic, or reacts violently with water,

if it has been, or is liable to be classified, pursuant to regulation 5 of the Chemicals (Hazard Information and Packaging for Supply) Regulations 1994[(a)], as the case may be, oxidising, toxic, very toxic or reacts violently with water.

2

(a) SI 1994/3247.

Guidance

Schedule 2

165 This Schedule sets out the dangerous fluids which determine the application of the more stringent additional duty requirements of regulations 19 to 27. These duties apply to pipelines conveying fluids in such conditions which are considered to have the potential to cause a major accident (as referred to in regulation 18).

Guidance

166 In general the Schedule applies generic categories for the application of the Regulations. This Schedule lists the categories of fluids and, where appropriate, the conditions and pressures under which they are transported. It is not considered appropriate to include the concept of qualifying quantities for a pipeline.

167 Paragraph 1 of Schedule 2 covers liquefied gases which are flammable in air when they are conveyed as a liquid. This includes butane and propane when conveyed in a pipeline as a liquid.

168 Paragraph 2 of Schedule 2 is applicable to flammable gases conveyed as a gas. In such cases the additional duties only apply when the flammable gas is conveyed at a pressure in excess of 8 bar absolute. This covers such fluids as methane, butane and propane when conveyed as a gas.

169 Mixtures of gas and liquid which have a vapour pressure in excess of 0.5 bar above atmospheric pressure when in equilibrium with its vapour are included. The intention is that this will cover pipelines conveying spiked crude which could have a considerable vapour pressure associated with it as well as pipelines which could be conveying fluids with a presence of sour gases. To determine whether the fluid attracts the additional duties, it is necessary to establish whether the gaseous element will separate out from the liquid with time to produce a pressure in excess of 1.5 bar absolute. The definition thus excludes stabilised crude oils in which the vapour pressure of the dissolved gas is suppressed by the lower vapour pressure of other constituents.

170 Acrylonitrile when conveyed in a pipeline is deemed by these Regulations to be a dangerous fluid. Although only classified by regulation 5 in the Chemicals (Hazard Information and Packaging for Supply) Regulations 1994 (CHIP 2) as toxic, it has the potential to cause a major accident hazard and therefore the requirements of regulations 19 to 27 apply to pipelines conveying this fluid.

171 For the purposes of these Regulations, the categorisations of oxidising, toxic, very toxic or reacts violently with water are derived from regulation 5 in the Chemicals (Hazard Information and Packaging for Supply) Regulations 1994 (CHIP 2).

172 Toxic and very toxic gases when conveyed either as a liquid or a gas will attract the additional duties. This covers pipelines conveying ammonia, bromine, chlorine etc.

173 Toxic liquids pipelines are only considered to possess a major accident potential when the substance is sufficiently volatile. For this reason, only toxic liquids conveyed in a pipeline as a liquid with a saturated vapour pressure in excess of 0.4 bar absolute will attract the additional duties.

174 Very toxic liquids are similarly only considered to possess a major accident potential when either the liquid is sufficiently volatile or when the liquid is conveyed in the pipeline above a certain pressure. For instance, a fluid such as phenol is not sufficiently volatile to attract the additional duties unless conveyed at a pressure in excess of 4.5 bar absolute. Above this pressure it is likely that the liquid will be pumped rather than conveyed under a padding pressure.

175 Fluids classified as oxidising are considered to have a major hazard potential but only when conveyed as liquid. This would cover organic peroxides but would exclude gaseous oxygen.

Schedule 2

Guidance

Schedule 2

176 Other fluids which are considered to have the potential to cause a major accident hazard are substances which are assigned the risk phrase 14 'reacts violently with water'. This generic category covers substances such as oleum and acid chlorides such as chlorosulphonic acids.

Requirements for emergency shut-down valves on certain major accident hazard pipelines connected to offshore installations

Schedule

3

Schedule 3

Regulation 19

1 An emergency shut-down valve shall be incorporated in the riser of a pipeline -

(a) in a position in which it can be safety inspected, maintained and tested; and
(b) so far as is consistent with sub-paragraph (a), as far down the riser as is reasonably practicable;

and such valve shall comply with the remaining paragraphs of this Schedule.

2 An emergency shut-down valve shall be held open by an electrical, hydraulic or other signal to the mechanism for actuating the valve on the failure of which signal the valve shall automatically close.

3 An emergency shut-down valve shall also be capable of being closed -

(a) by a person positioned by it; and
(b) automatically by the operation of the emergency shut-down system of the offshore installation to which the pipeline is connected,

or, while relevant work of examination or maintenance is being carried out, by one of those means.

4 If the pipeline is designed to allow for the passage of equipment for inspecting, maintaining or testing the pipeline, the emergency shut-down valve shall also be designed to allow for such passage.

5 An emergency shut-down valve and its actuating mechanism shall so far as is reasonably practicable be protected from damage arising from fire, explosion or impact.

6 An emergency shut-down valve shall be maintained in an efficient state, in efficient working order and in good repair.

Schedule 3

7 After an emergency shut-down valve has operated so as to block the flow of fluid within the pipeline it shall not be re-opened so as to permit the flow of fluid until steps have been taken to ensure that it is safe to do so.

8 In this Schedule "emergency shut-down system" means the system comprising mechanical, electrical, electronic, pneumatic, hydraulic or other arrangements by which the plant on an offshore installation is automatically shut down in the event of an emergency.

Guidance

177 This Schedule sets out the requirements for emergency shut-down valves (ESDVs) on risers which are part of major accident hazard pipelines of 40 mm or more internal diameter at offshore installations under regulation 19.

178 This Schedule requires every riser of 40 mm or more internal diameter which forms part of a major accident hazard pipeline be fitted with an emergency shut-down valve and that the valve is maintained in good working order.

179 The ESDV should be located so that the distance along the riser between the valve and the base of the riser is as low as reasonably practicable, in order that the most vulnerable section of the riser can be isolated from the majority of the pipeline inventory. However, it is equally important that the ESDV can be safely maintained and tested so that it can function properly. It follows that it is important to locate the ESDV above the highest wave crest which can reasonably be anticipated so that the valve can be tested and maintained.

180 Where flexible risers are used, the ESDV should be located on the in-board side of the quick connect/disconnect couplings (QCDC), if fitted, and above the highest wave crest which can reasonably be anticipated.

181 The ESDV location, design, testing, maintenance and operation should ensure that the ESDV will at all times operate on demand or fail-safe in the closed position, so minimising the possibility of an uncontrolled release of the pipeline inventory. Once closed the ESDV should not be reopened until the safety of the installation and connected installations is assured.

182 The ESDV should be capable of stopping the flow of the fluid within the pipeline. However, this disregards minor leakage past the ESDV which cannot represent a threat to safety. The operator should make an assessment of the maximum internal rate that can be tolerated. The rate of leakage should be based on the installation's ability to control safely the hazards produced by such a leak.

183 ESDVs should be rapid-acting isolation valves, capable of being operated remotely by the operation of the associated installation's emergency shut-down system or locally by a person positioned by it.

184 Where maintenance or examination of the ESDV is being carried out which involves disabling one of the two actuation systems while the work is being undertaken, this is permissible provided that once the work is completed both the actuating mechanisms are returned to full working order.

185 If the pipeline of which the riser forms part has been designed to allow the passage of equipment, such as pigs for inspection etc, the ESDV should be designed to allow the passage of that equipment. For example, in the case of a piggable pipeline system, the ESDV should also be piggable and therefore a ball or gate valve is likely to be used.

Schedule 3

Guidance

186 The valve and its actuating mechanism are required to be protected, so far as is reasonably practicable, against fire, explosion and impact. The aim is that, under all foreseeable conditions, the ESDV should be capable of closing fail-safe. The extent of the protection system should at least cover the ESDV, its actuator and any components required for fail-safe closure of the valve.

187 In order to define the type and extent of fire protection required the operator will need to consider the type, severity and duration of anticipated tires as well as the minimum duration for which the integrity and operability of equipment to be protected must be maintained.

188 It is not usually reasonably practicable to afford protection against all the effects of an explosion in the immediate vicinity of an ESDV. In general explosion protection is best achieved by locating the ESDV well outside congested equipment modules.

Relationship with other Regulations

189 Regulation 5 of the Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations 1995 (PFEER) requires the owner or operator of an installation to carry out an assessment of the major accident hazards involving fire or explosion, and to identify appropriate arrangements to deal with them. The information about major accident hazards and the measures taken to reduce risks in this regulation can be used to demonstrate that the ESDV is capable of adequately blocking the flow of fluid within the pipeline riser in the Pipelines Safety Regulations 1996.

Schedule 3

Particulars to be included in notification relating to construction of a major accident hazard pipeline

Schedule

Schedule 4

Regulations 20 and 27(1) and (2)

1 The name and address of the operator of the pipeline.

2 The proposed route of the pipeline in the form of maps or drawings.

3 The proposed route of the riser on any offshore installation, in the form of drawings.

4 The length, diameter and wall thickness of the pipeline.

5 The materials to be used in the construction of the pipeline.

6 The fluid to be conveyed and such of its properties as are relevant to health and safety.

4

Schedule

4

7 The safe operating limits of the pipeline.

8 The intended temperature, pressure, and maximum rate of flow of the fluid to be conveyed.

Guidance

190 This Schedule sets out the information to be included under regulation 20. This notification may form the first contact between the pipeline operator and HSE; earlier contact may be helpful. This 'end of concept design' notification should be made at a point where the design is sufficiently well enough advanced to be able to set out, in general terms, the particulars required in this Schedule but not so late that the company has already committed major expenditure.

191 Only a limited amount of information about the pipeline is required at this notification stage. This notification is aimed at triggering HSE's inspection arrangements and it will provide the basis for the start of a dialogue between the pipeline operator and HSE about arrangements to secure the safety of the pipeline. The intention behind this notification is to ensure that HSE is made aware of the proposed pipeline before major expenditure has been committed, since it is at this early stage that the most recent and best practice of design, and use of materials, can be applied at least cost. Where some of the information cannot, at the time of notification, be fully specified, notification to HSE should go ahead together with details of when the further information may be provided, by agreement between the operator and HSE. The information that is supplied will help HSE to form a view on appropriate inspection arrangements.

192 The information to be supplied need only represent the particulars as far as they have been developed by this stage. It is likely that there may be minor changes to the information, but where the changes are significant to the level of risk of the pipeline, these further details should be supplied to HSE.

Schedule 4

Particulars to be notified before certain events relating to major accident hazard pipelines

Schedule

5

Schedule 5

Regulation 22(2) and (3)

1 In relation to a change to the route or position of a pipeline, particulars in the form of maps or drawings of the new route or position.

2 In relation to a change to the safe operating limits of a pipeline, particulars of such change.

3 In relation to the start of major modification or major remedial work to the pipeline, particulars of such work.

Schedule

5

4 In relation to the conveyance of a new fluid, particulars of -

(a) such of its properties as are relevant to the health or safety of persons; and

(b) the intended or (if, in a case to which regulation 22(3) applies, conveyance has started) actual temperature, pressure and maximum rate of flow in the pipeline.

5 In relation to the start of decommissioning or dismantlement of the pipeline, particulars of the steps to be taken or (if, in a case 10 which regulation 22 (3) applies, decommissioning or dismantlement has started) taken in connection with such decommissioning or dismantlement.

Guidance

193 These notifications concern changes to a major accident hazard pipeline, its operation or environment which may have an effect on the pipeline integrity or level of risk from, or to, that pipeline.

194 This would include prior notification of changes to the position of a pipeline, design intent (including change of use), safe operating regime, end of use or any change in the level of risk for any reason.

195 There is a clear distinction between pipeline works which involve risks to those actually carrying out the work and changes to the pipeline which could affect the level of pipeline risk. These notifications are not intended to include notification of pipeline works.

196 The level of pipeline risk can be affected or altered due to a number changes, some of which are similar to those principal items used at the notification of construction activities:

- route or position;
- service conditions;
- pipeline materials and equipment.

Changes in position or route

197 The proximity of a major accident hazard pipeline relative to occupied buildings or with respect to its position on an offshore installation is a safety critical item and has a significant impact on risk levels. For example, notifications would be required for changes to:

- the route or position of a pipeline, including pipeline diversions because of new developments or encroachments and for tie-ins to new installations, other pipelines, etc;
- the route or position of pipeline risers on offshore installations including diversions to separate riser platforms.

Changes in fluid composition or type

198 If the range of properties of the conveyed fluid is expected to change from those specified or anticipated at the original design stage, then those changes are notifiable. Pipelines may be initially designed to transport one type of substance or fluid, but there may come a time when there is a requirement to use the pipeline for other purposes, eg to change from oil production to water injection (to increase field life), from oil to gas, etc. The composition of a fluid may change significantly during the life of a field development, eg from sweet to sour gas or oil, which may or may not have been taken into account at the initial design stage.

Schedule 5

Guidance

Changes in safe operating limits

199 Changes in the maximum allowable operating pressure (MAOP) of a pipeline, whether temporary or permanent, are notifiable. Where a pipeline MAOP may have to be temporarily or permanently lowered following damage to the pipeline or because of developments in close proximity to the pipeline, this information should be notified to HSE.

200 A pipeline MAOP may need to be raised above the original design pressure in some cases. If this is proposed, it will probably have significant implications on the pipeline integrity and risk levels which must be fully evaluated.

End of use of a pipeline

201 Notification would be required of plans to decommission on a long-term basis, 'moth-ball' or finally decommission a pipeline.

Changes in pipeline materials and equipment

202 Notifications should be made where there are changes to critical dimensions (wall thickness, diameter) of a pipeline such as installation of thicker-walled pipe sections for protection or proximity infringements.

203 Replacement of pipelines or sections of pipelines (eg due to severe damage or corrosion) should be notified where the new material is different from the existing material. Steels of a different standard or strength may have been selected or materials may be changed from 'hard' pipe to flexible or composite pipeline sections (or vice versa).

What is not notifiable?

204 Notification to HSE need not be made for:

- any changes to pipeline not defined as a major accident hazard pipeline, unless that change results in that pipeline falling under the additional duties, eg change of use from conveying a low hazard fluid, such as stabilised crude oil, to an extremely flammable liquid or flammable gas;
- repairs to a pipeline following a reportable dangerous occurrence under the Reporting of Injuries, Diseases and Dangerous Occurrences Regulations 1995 (RIDDOR);
- replacement on a like-for-like basis of components or sections of a pipeline, including flexible riser and pipeline replacement on a planned basis;
- minor adjustments to the pipeline operating system (control systems, leak detection, etc);
- running repairs (slight surface damage repairs, coating and wrapping repairs, rectification of spans, replacement of cathodic protection systems, repairs to protective slabbing or concrete mattresses, etc);
- routine inspection and maintenance work and the results of any surveys and changes to the inspection and maintenance scheme;
- pigging operations both routine and special operations, eg on-line inspection using intelligent pigs;
- retesting of pipelines for leak tightness.

Schedule 5

Revocation and modification

Schedule 6

Schedule 6

Regulation 31

Part I Revocation of instruments

1 *Title*	2 *Reference*	3 *Extent of revocation*
The Gas Safety Regulations 1972	SI 1972/1178	The whole Regulations
The Gas (Metrication) Regulations 1980	SI 1990/1851	Regulation 3(1)
The Submarine Pipe-lines Safety Regulations 1982	SI 1982/1513	The whole Regulations except regulations 1 (1) and 11
The Submarine Pipe-lines Safety (Amendment) Regulations 1986	SI 1986/1985	The whole Regulations
The Offshore Installations (Emergency Pipe-line Valve) Regulations 1989	SI 1989/1029	The whole Regulations
The Submarine Pipe-lines (Inspectors and Safety) (Amendment) Regulations 1991	SI 1991/680	Regulation 3

Part I

Schedule 6

Part II Modification of the Notification of Installations Handling Hazardous Substances Regulations 1982

1 In the definition of "installation" in paragraph (1) of regulation 2 (interpretation) of the 1982 Regulations the words "or pipe-line" shall be omitted.

2 In regulation 3 (notification of installations handling hazardous substances) of the 1982 Regulations -

(a) in paragraph (1) the words -

(i) "or in any pipe-line to which paragraph (4) applies"; and
(ii) "the appropriate part of" shall be omitted; and

(b) paragraph (4) shall be revoked.

3 In regulation 4 (updating of the notification following changes in the notifiable activity) of the 1982 Regulations the words "or in the pipe-line" shall be omitted.

4 In regulation 5 (re-notification where the quantity of a substance is increased to 3 times that already notified) of the 1982 Regulations the words "of Part I" shall be omitted.

Part II

Schedule 6

Part II

5 *In Schedule 2 of the 1982 Regulations -*

(a) the title "Part I" shall be omitted; and
(b) Part II shall be revoked.

Further information

For information about health and safety, or to report inconsistencies or inaccuracies in this guidance, visit www.hse.gov.uk/. You can view HSE guidance online and order priced publications from the website. HSE priced publications are also available from bookshops.

British Standards can be obtained in PDF or hard copy formats from BSI: http://shop.bsigroup.com or by contacting BSI Customer Services for hard copies only Tel: 020 8996 9001 email: cservices@bsigroup.com.

APPENDIX 2 CCUS ENABLED PRODUCTION REPORT

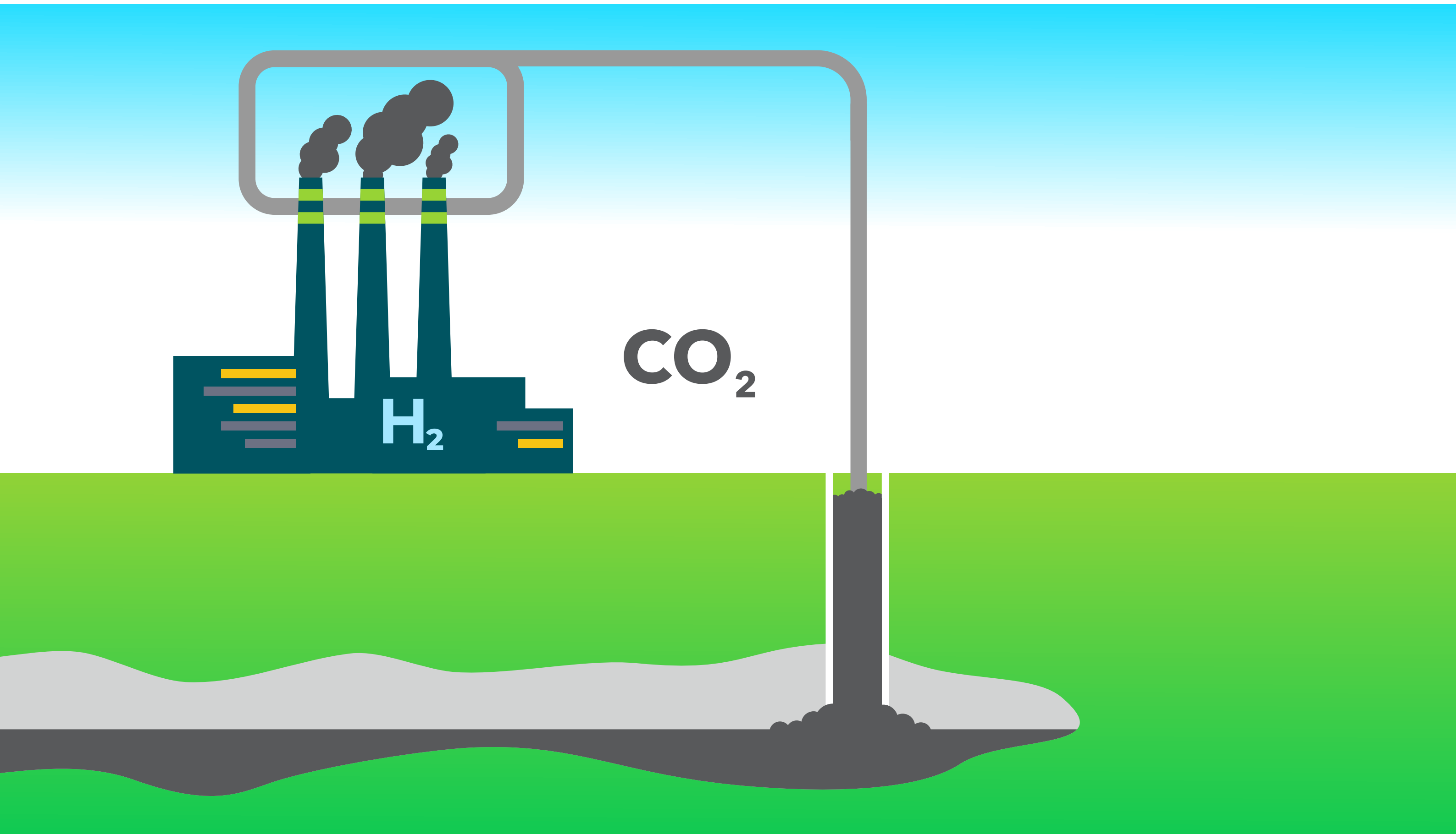
September 2023

Hydrogen UK

CCUS-Enabled Production Report

Written By

CCUS-Enabled Production Working Group



Contents

Executive Summary

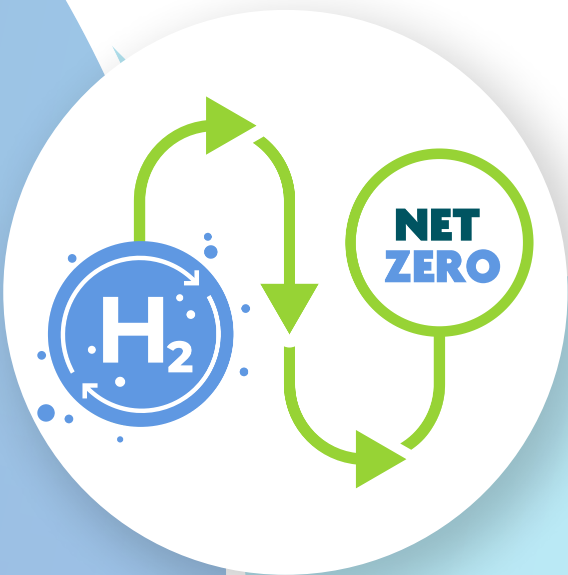
The UK has committed to achieving Net Zero by 2050. In all the major models of possible routes to Net Zero, hydrogen plays a significant role. To deliver the volumes of low carbon hydrogen required, the Government has pledged its support to both electrolytic and CCUS-enabled hydrogen, which is made from hydrocarbons with the carbon dioxide captured and used or permanently stored.

CCUS-Enabled Hydrogen is Low Carbon Hydrogen

DESNZ have produced a Low Carbon Hydrogen Standard (LCHS) to ensure that all hydrogen that receives government support is produced in a manner that is compliant with the UK's Net Zero targets. The LCHS is one of the most stringent standards in the world for carbon emissions, and hydrogen produced in the UK using CCUS-enabled technology, such as that being proposed for use in the industrial clusters, can easily meet the definition of 'low carbon'. Novel technologies currently being brought to market offer the capability of producing low carbon hydrogen that can be applied to decarbonising smaller industrial processes away from the major clusters.

CCUS-Enabled Hydrogen Delivers at Scale and Pace

CCUS-enabled hydrogen can deliver hydrogen production suitable for individual industrial facilities or on a gigawatt (GWs) scale in a relatively short space of time. The nature of the technology lends itself to large scale facilities that can be delivered in modules of 100s of MW, but the development of new production pathways that output solid carbon (rather than carbon dioxide gas) will mean that hydrogen can also be produced away from carbon dioxide networks and at smaller scales. When multiple projects are delivered concurrently, this kick-starts the hydrogen economy, allowing the UK to go further and faster in its efforts to decarbonise.



Hydrogen UK

CCUS-Enabled Hydrogen Can Decarbonise Hard to Abate Industrial End Users

Many of the hardest to abate industries are found in industrial clusters. Many heavy emitting industrial processes will require significant volumes of reliable, baseload low carbon hydrogen. This makes them ideally located for access to large scale CCUS-enabled hydrogen production which can be deployed in clusters to aggregate demand and make use of shared infrastructure. Similarly, newer production pathways will also enable industrial decarbonisation away from the industrial clusters and carbon dioxide transport networks.

CCUS-Enabled Hydrogen Relieves Pressure on Renewable Deployment

Electrolytic hydrogen and renewable electricity have an important role to play in the decarbonisation of energy in the UK. However, the deployment of both will be limited by a variety of factors. CCUS-enabled hydrogen production provides a viable, low carbon alternative which can alleviate pressure on the already constrained electricity grid, allowing renewable electricity generation and electrolytic hydrogen production to scale at a more manageable pace. This benefit of CCUS-enabled hydrogen in the years out to 2035 has been explicitly recognised in the Committee on Climate Change's recently published '*Delivering a Reliable Decarbonised Power System*'[1].

Economic Growth and UK Expertise

There are significant economic benefits to the UK pursuing CCUS-enabled hydrogen. These include but are not limited to job creation, GVA and utilising the extensive UK expertise in the oil and gas industry. The UK is also home to a range of companies developing innovative production technologies which generate solid carbon products, as well as hydrogen, for use in other processes. Supporting production can foster the development of domestic supply chains, reduce reliance on imported low carbon hydrogen, and if supply exceeds demand, offer an opportunity to export to other regions.

Figure 1: A Steam Methane Reformation Unit

The Role of Hydrogen in Net Zero for the UK

Hydrogen is a fuel with zero direct carbon emissions at the point of use that can help to decarbonise multiple sectors of the UK economy. **Table 1** outlines some of the end-use applications that hydrogen can be used to decarbonise.

Sector	Prominent example	Technology	Replacing
Industry	Steel manufacture	Direct iron reduction using hydrogen	Natural Gas
	Glass manufacture	Hydrogen kiln	Natural Gas
	Food & Drink manufacture	Hydrogen boiler or hybrid	Natural Gas
Transport	Road (Light and Heavy Vehicles)	Fuel cell or hydrogen ICE	Petrol and Diesel
	Rail	Fuel cell	Diesel
	Maritime	Ammonia or synthetic methanol ICE or fuels cell	Bunker Fuel
	Aviation	Multiple prospects	Kerosene
Buildings	Domestic heating	Hydrogen boiler or hybrid	Natural Gas
	Commercial heating	Hydrogen boiler or hybrid	Natural Gas
Power Generation	Flexible power generation	Hydrogen CCGT / GT/ reciprocating engine	Unabated Natural Gas

Table 1: End Use Examples of Hydrogen

Hydrogen will play a crucial role in reaching the UK's mandated Net Zero ambition by 2050. The UK Hydrogen Strategy estimates that to meet Net Zero by 2050, hydrogen will make up 20-35% of the UK's final energy demand (250-460 TWh a year)[2], a significant increase from the 10-27 TWh currently being produced[3]. Hydrogen will enable the decarbonisation of hard to abate sectors including industry, heavy transport, dispatchable power generation and potentially heat. **Figure 2** from the UK Hydrogen Strategy[4] indicates what hydrogen demand could look like in 2030 and 2035 across the industrial, power, heat and transport sectors (note that these demand figures were issued before the Government doubled its hydrogen production capacity target for 2030).

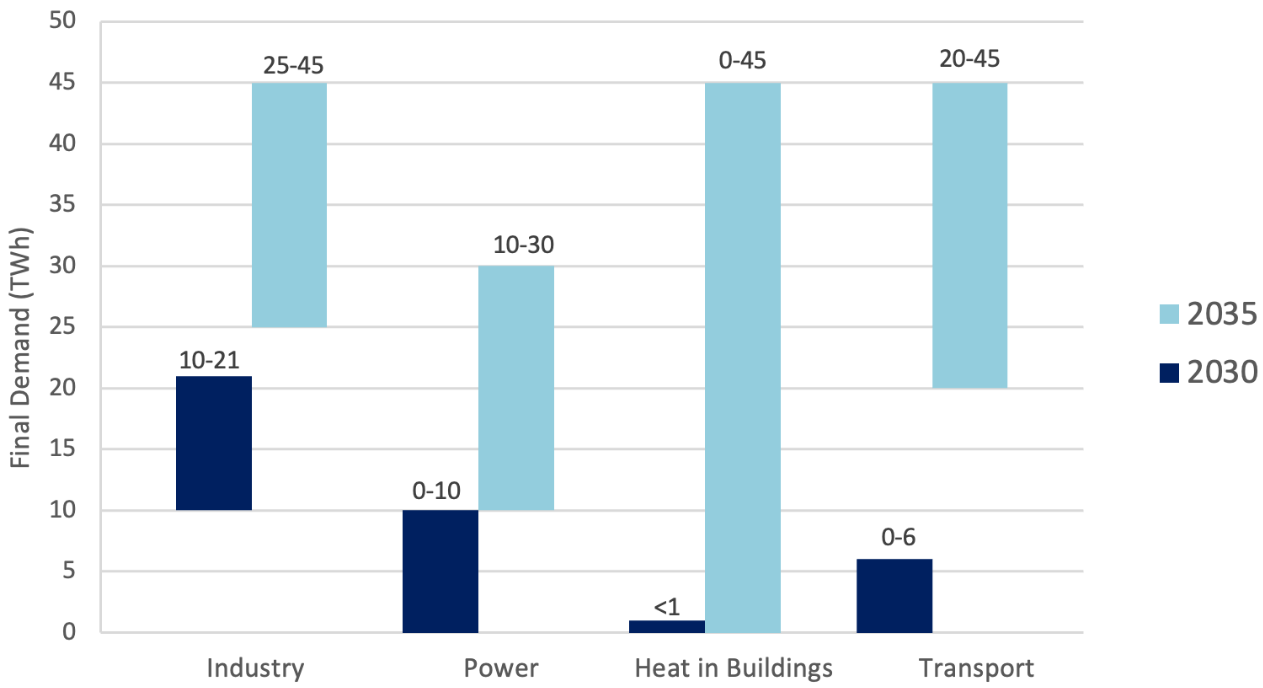


Figure 2: Estimated UK Hydrogen Demand for Hydrogen by Sector[3]

Hydrogen UK

This will be achieved via a twin track approach between electrolytic and CCUS-enabled hydrogen production. The Department for Energy Security and Net Zero (DESNZ), formerly the Department for Business, Energy and Industrial Strategy (BEIS), have supported CCUS-enabled hydrogen as a sector through legislation and support mechanisms. A crucial mechanism that DESNZ have developed is the Low Carbon Hydrogen Standard (LCHS). This standard details a maximum GHG emission intensity of 20g CO_2e/MJ_{LHV} in the production process of hydrogen for it to be deemed as 'low carbon'[5].

For CCUS-enabled hydrogen, the LCHS stands as a stringent threshold that must be met in order to access governmental funding, thus helping to make hydrogen production with higher levels of associated carbon emissions unaffordable.

CCUS-Enabled Production Methods

Methane Reformation with Gaseous CO_2 Product

A significant portion of hydrogen produced currently involves the reformation of natural gas (methane). The most common production method globally is via Steam Methane Reforming (SMR)[6]. This process involves heating methane to high temperatures in the presence of a catalyst to form a syngas mix of hydrogen, carbon dioxide, and carbon monoxide. Following this the carbon monoxide is further converted to create more hydrogen and carbon dioxide via a water gas shift reaction. The Auto Thermal Reforming (ATR) of methane is a process whereby partial oxidation and steam reforming are used to produce a syngas mix of carbon monoxide and hydrogen. The syngas can then be purified, similarly to SMR, to obtain hydrogen and carbon dioxide. The Partial Oxidation (POX) of methane can also be used to produce hydrogen in a separate process from ATR. Here, hydrogen is produced via a non-catalytic oxidative reforming process where methane is reacted with a limited amount of oxygen so complete oxidation cannot occur.

The reformation of natural gas for hydrogen production currently releases carbon dioxide, the main greenhouse gas emission contributing to anthropogenic climate change, as a by-product. To reduce the harm caused from this release, Carbon Capture, Utilisation and Storage (CCUS) technology can be incorporated with the aim of removing up to 97% of the carbon dioxide produced during hydrogen production[7]. The captured carbon dioxide can then be compressed and transported by pipeline or ship for permanent storage underground in geological formations. Hydrogen produced using these processes that do not implement CCUS technology are referred to as 'grey hydrogen'; with the introduction of CCUS, they are deemed as 'blue hydrogen'.

Figure 3: An Autothermal Reforming (ATR) Plant[4]

The UK Hydrogen Strategy details estimates for the levelized cost of SMR and ATR processes for 2050. A 300 MW ATR plant with Carbon Capture and Storage (CCS) in the UK is estimated to produce hydrogen at £65/MWh in 2050, whilst an equivalent capacity SMR plant with CCS will produce hydrogen at £67/MWh[8]. CCUS technology can be attached to both SMR and ATR plants, with expected carbon capture rates of 90% and 97% respectively.[9]

Methane with Solid State Carbon Product

CCUS-enabled production of hydrogen will include a range of novel technologies, particularly technologies that produce solid carbon. The pyrolysis of hydrocarbons, typically methane, is one example. Here, a hydrocarbon is pressurised and heated to a high temperature in the absence of oxygen and thus, hydrogen gas ('turquoise hydrogen) is produced alongside solid carbon[10]. Thermal Plasma Electrolysis (TPE) is another notable CCUS-enabled method of hydrogen production that outputs solid carbon rather than carbon dioxide gas. This process uses plasma torches to split hydrocarbon feedstocks (typically methane, flare gas or biomethane) into hydrogen ('emerald hydrogen') and carbon via the application of an intense electrical field rather than heat[11]. When biomethane feedstock is then coupled with the output of solid carbon in this way, TPE offers an attractive route to delivering negative emissions. Microwave plasma can also be used to crack methane into its constituent atoms, producing hydrogen alongside solid carbon.

The solid carbon produced by these technologies can be isolated, collected and then sequestered. Alternatively, the output may be used as a material in industrial and technological sectors, displacing solid carbon produced by existing highly emissive processes. Potential end uses range from graphene and other advanced materials to soil enhancement and agriculture feeds.

In the UK Hydrogen Strategy, the role of methane pyrolysis is described as 'nascent technology' that requires further research and development to play a major future role[12], yet it is already apparent that technologies such as thermal plasma electrolysis and methane pyrolysis will be vital as decentralised CCUS-enabled production methods delivering hydrogen away from industrial clusters.

Biomass Gasification

Greenhouse Gas Removal technologies (GGRs) have been highlighted by both the Intergovernmental Panel on Climate Change (IPCC) and the Climate Change Committee (CCC) as a necessity in reaching net zero targets[13]. The gasification of biomass coupled with CCUS technology allows for production of low carbon hydrogen alongside the potential of negative carbon emissions. The UK is pioneering the demonstration of CCUS with biomass power generation, with DRAX leading the efforts within Bioenergy CCS (BECCS) technology, submitting plans to build the world's largest carbon capture and storage plant last year[14]. The DESNZ funded Hydrogen BECCS Innovation Programme has awarded £30 million to nearly 30 organisations across feedstock pre-processing, gasification components and novel biohydrogen technologies[15].

Summarising the Benefits of CCUS-Enabled Hydrogen Production

Retrofit to Existing Hydrogen Production

At the end of 2021, 47% of global hydrogen production used natural gas as a feedstock in comparison to just 4% from electrolysis[16]. The remaining 49% relies on oil or coal as the feedstock for hydrogen production which are highly emissive of carbon dioxide, and thus needs to be replaced with low carbon hydrogen as soon as possible. Carbon Capture, Utilisation and Storage (CCUS) technology can be incorporated in not only new build but also existing hydrogen production plants. This offers a significant opportunity to decarbonise the current fleet of fossil-fuel based hydrogen production facilities, transitioning them, and their offtakers, from high to low carbon hydrogen.

Low Carbon Hydrogen at Scale

The deployment of CCUS-enabled hydrogen allows for production of low carbon hydrogen at significantly greater levels and at an earlier date than is going to be feasible without it. Gigawatt scale CCUS-enabled production will become operational sooner than equivalent electrolytic production projects, thus allowing the decarbonisation of hard-to-abate sectors to commence at an earlier date. CCUS-enabled hydrogen production can be used to produce baseload volumes of hydrogen from day one. This will enable electrolytic hydrogen, which will likely face initial challenges around the deployment and intermittency in of renewable electricity generation, as well as limited access to hydrogen storage, to scale alongside the development of hydrogen transport and storage infrastructure. This allows hydrogen supply to scale up rapidly during the 2020s, enabling the full hydrogen supply chain to be developed sooner than would be achieved without CCUS-enabled production, something that could in fact help early electrolytic projects come to market.

An early and large-scale hydrogen supply allows emitters who are looking to decarbonise their processes early, across a range of sectors, to choose a hydrogen pathway. This avoids emitters being forced to choose what may end up being a potentially sub-optimal solution in the long term simply because they lack access to a supply of low carbon hydrogen.

Since CCUS-enabled hydrogen can be scaled up quickly, it can provide the supply of low carbon hydrogen needed for early, consistent, and strong decarbonisation action to be taken where it will have the largest impact on meeting the UK's 2050 carbon budget. Furthermore, developing CCUS-enabled production infrastructure within the UK will lay the groundwork for opportunities across the entire CCUS sector. Industries such as industrial CCUS, power bioenergy carbon capture and storage (BECCS) and gas-CCS power generation are essential to reaching net zero and will be able to springboard off the large-scale deployment of CCUS-enabled hydrogen production infrastructure.

Achieving Interim Carbon Budgets

CCUS-enabled hydrogen allows for greater decarbonisation to occur during the 2020s when it is most effective for reducing the overall level of GHGs in the atmosphere. Ultimately net zero is just an end point target. The total level of emissions released by the UK between now and net zero 2050, and hence our impact upon the climate, will be determined in large part by the action we take to decarbonise in the 2020s and early 2030s. A steel mill decarbonised by hydrogen in 2040 will add ten more years to cumulative emissions than one decarbonised in 2030. Net Zero by 2050 still comes with a certain degree of temperature change so reducing carbon emissions sooner will limit this change and the potential damage that this could cause.

Making Use of the UK's Natural Resources and Existing Energy Infrastructure

To deploy large scale CCUS-enabled technology, a large capacity of carbon dioxide storage is required. **Figure 4**, from the Energy Technology Institute[17], overlays the top 50 carbon dioxide emitters in the UK with the location and capacity of potential

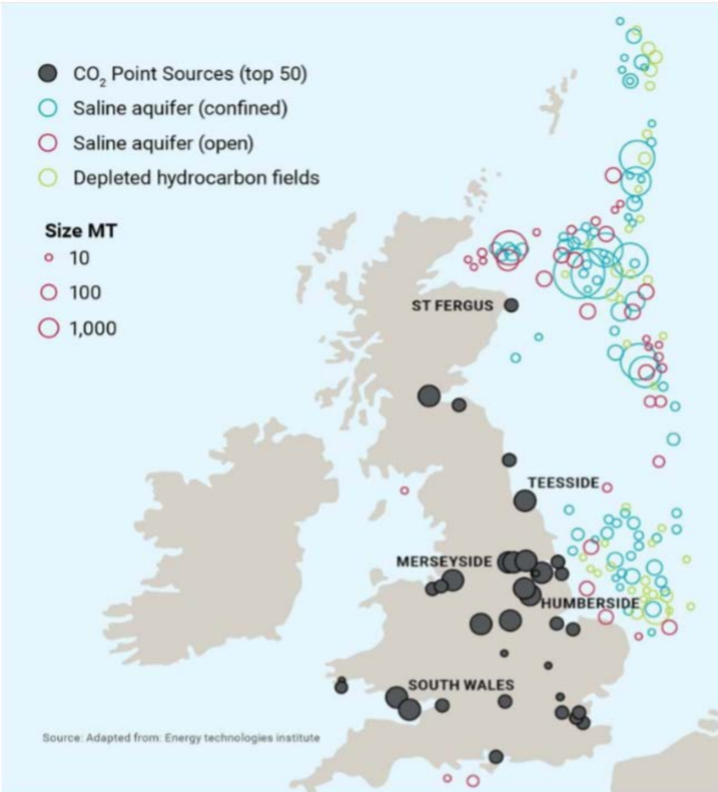


Figure 4: Top 50 carbon emitters – location relative to potential CO_2 storage[16]

Hydrogen UK

carbon dioxide storage. The UK is fortunate to have access to saline aquifers and depleted hydrocarbon fields close to industrial clusters enabling the large-scale deployment of CCUS-enabled technology. Meanwhile, nascent hydrogen with solid carbon production technologies can make use of existing natural gas and electricity networks to deliver low carbon hydrogen production close to the point of use, with solid carbon as a potentially valuable by-product. Initially, these technologies could provide hydrogen for discrete applications with a potential for future scale up.

Reducing the Pressure on Renewable Deployment

CCUS-enabled hydrogen further relieves pressure on UK renewable build out. Electrolytic hydrogen will be crucial to meeting net zero aims producing carbon free hydrogen. The UK's electricity demand is set to increase significantly due to the increase in electrolytic production alongside the increased electrification of sectors such as power generation, transport and heat. In National Grid's Future Energy Scenarios, peak electricity demand increases from c.60 GW in 2022 to c.100GW in 2050, within the System Transformation scenario[18]. Hydrogen UK has mapped the renewable power demand needed to meet total hydrogen demand if electrolytic hydrogen was the sole method of hydrogen production and using the CCC balanced pathways scenario. As **Figure 5** shows, between 60% and 114% of the total renewable capacity would be needed in 2050 to meet this demand[19]. CCUS-enabled hydrogen production can help alleviate the electricity demand required for hydrogen production and enable the decarbonisation of other sectors via electrification.

In the UK, 53% of industrial emissions come from industrial clusters[20]. Government has identified that UK clusters support high quality jobs that pay above the average national wage and are critical to the local economy[21]. However, these cluster sites need intervention to ensure they comply with net zero aims and can continue driving growth and export pportunities within the UKs industrial sector. CCUS-enabled hydrogen production provides a pathway for these cluster sites to continue generating the benefits they bring.

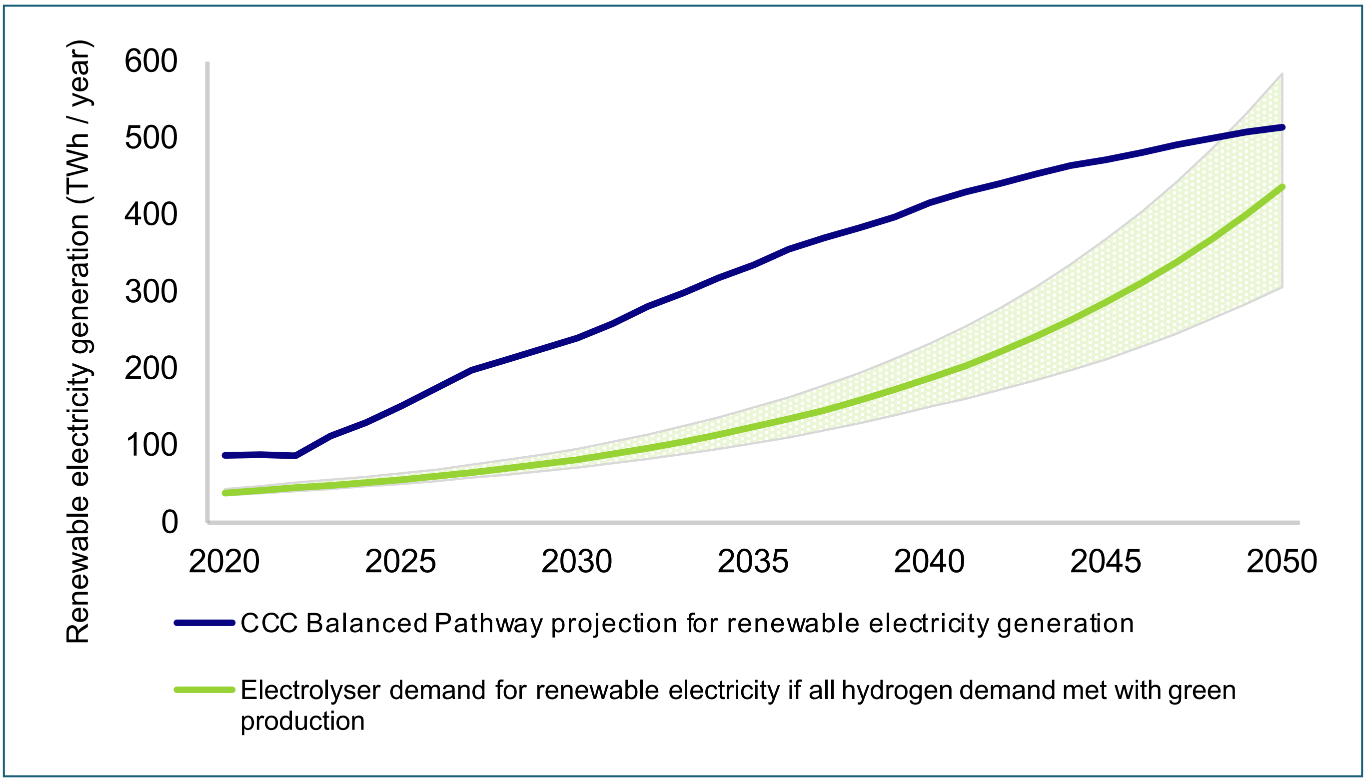


Figure 5: Range of renewable electricity generation required for projected[20].

DESNZ have stated their ambition to:

1. Have at least two low carbon clusters built and operating by 2025,
2. Have at least four low carbon clusters operating by 2030 capturing 10MtCO_2/year. In October 2021 the government increased the carbon capture ambition to 20-30MTCO_2/year by 2030[22].

Whilst the majority of industrial emissions are generated via these cluster sites, a significant proportion of emissions (47%) are dispersed outside of these cluster sites across the nation[23]. Hydrogen networks and dispersed electrolytic production will have a large role to play in the decarbonisation of these emissions as well as novel CCUS-enabled technologies, such as methane pyrolysis, that can be used to decarbonise industrial sites outside of clusters before hydrogen networks are operational. Moving to a low carbon industry is a significant opportunity for the UK to pioneer and seize a large share of a growing global market[24]. DESNZ estimate that UK industry contributes a GVA of approximately £150 billion per year to the UK economy, securing around 1.5 million jobs and exporting goods and services with a value around £320 billion[25]. CCUS-enabled technologies, specifically in low carbon hydrogen production, will be fundamental in the transition to low carbon industry and maximising this opportunity.

Economic Benefits and Utilising UK Expertise

There are significant economic benefits to the UK pursuing CCUS-enabled hydrogen. These include but are not limited to job creation, GVA and utilising the extensive UK expertise in the oil and gas industry.

In 2020, the Hydrogen Taskforce estimated that CCUS-enabled hydrogen could deliver £2.8bn in cumulative GVA and over 10,000 cumulative jobs by 2035[26].

A North Sea Transition Deal report, titled 'Integrated People and Skills Strategy', states that 90% of the UK's oil and gas workforce have skills transferability to adjacent energy sectors. One of the sectors identified as having high transferability is CCUS-enabled hydrogen[27]. Furthermore, a report by Element Energy for The Engineering Construction Industry Training Board (ECITB) suggests that hydrogen production from reforming natural gas will have similar skills requirements to the existing chemical and oil and gas industries with low requirements for training. The main upskilling requirements will be in CO_2 capture, infrastructure and storage[28]. The Green Jobs Taskforce made a similar finding of minor retraining requirements[29]. The skills requirements for CCUS-enabled hydrogen production are shown in more detail in the infographic reproduced in **Figure 6**.

Inevitably, skills requirements will be informed by the data that government has been gathering as part the cluster sequencing process[30]. These submissions contain a wide range of information including job title, activity type, skill level (NVQ), location, whether the job is created, safeguarded or displaced, direct or indirect, and salary.

Hydrogen technologies

	Key technology components	Relevant industries: Chemical	FEED & Design	Renewables	Power Generation	Oil & Gas	Nuclear	Water Treatment	Time-frame	Skills Impact	Comments on skills and industry similarities
Hydrogen Production – Adv. gas reform	Air separation unit, metallic structures, compressors	●	●	○	○	○	○	○			Existing skills similar to the chemical and oil and gas industries

CCS technologies

	Key technology components	Relevant industries: Chemical	FEED & Design	Renewables	Power Generation	Oil & Gas	Nuclear	Water Treatment	Time-frame	Skills Impact	Comments on skills and industry similarities
CCS capture plants	Capture plant, compressors, exchange columns, pipework2	○	●	○	●	○	○	○			Minor upskilling needed for welding, erection, testing and inspection; similar to chem ind.
CO_2 transport infrastructure	Onshore and offshore pipeline laying	○	●	○	○	●	○	○			Minor technical upskilling for handling of new materials for CO_2 pipelines
CO_2 Storage	Offshore pipeline, injection wells, monitoring	○	●	○	○	●	○	○			Minor upskilling might be needed for oil and gas personnel in FEED and monitoring stages

Industry Sector Key

Chemical | Food & Drink | Nuclear | Renewables | Oil & Gas | Pharmaceuticals | Power Generation | Water Treatment | FEED & Design

Figure 6: Skills requirements for CCUS-enabled hydrogen[29]

Export Opportunity

A significant export opportunity exists with the growth of the UK CCUS-enabled hydrogen production sector. The UK is home to pioneering companies within the CCUS sector, including world leading oil and gas companies and those developing CCUS-enabled hydrogen production technology, such as Johnson Matthey's LCH™ technology which is already licensed internationally. There is potential for the UK to not just export CCUS technology, but also to export technical expertise, especially to neighbouring nations within Europe. These benefits remain pertinent within the nascent solid carbon technology sector, where the UK hosts front-running companies like HiiROC[31] and Levidian[32]. The UK has the potential to pioneer on a global stage acting as a net exporter of both technological equipment and expertise, solidifying its reputation as global leader within the hydrogen and CCUS sector.

Emissions

Emissions Analysis of CCUS-Enabled Hydrogen

It is essential to recognise that achieving low emissions from CCUS-enabled hydrogen is not simply a pledge or an ambition. In the UK there is a regulatory requirement for low emissions for hydrogen producers to receive revenue support from the Hydrogen Production Business Models (HPBM) and capital funding from the Net Zero Hydrogen Fund (NZHF). Hydrogen production which fails to achieve the limit set by the Low Carbon Hydrogen Standard (LCHS), currently 20gCO_2e/MJLHV of produced hydrogen[i], is unlikely to be able to compete with supported hydrogen especially following the tightening of the emissions trading scheme in line with net zero[33]. **Figure 7** shows the carbon intensity of CCUS-enabled hydrogen under several scenarios using DESNZ's LCHS calculator[34]. The scenarios shown are:

- **Best Case** – this assumes very low upstream natural gas emissions with natural gas originating from Norway – it should be noted that producers cannot use this upstream emission factor in calculating their emissions intensity under the LCHS if natural gas is sourced through the UK gas network.
- **Central Case** – this assumes the UK weighted average natural gas upstream emissions with a CO_2 capture rate of 95%.
- **JM LCH** - this assumes UK weighted average natural gas upstream emissions but a higher CO_2 capture rate of 97.1% based on Johnson Matthey's LCH™ technology.

These CCUS-enabled hydrogen production emissions are then compared with grid electricity carbon intensity projections in 2025[35] and the Low Carbon Hydrogen Standard[ii]. In a more complete emissions comparison, the end use should be included as electric and hydrogen end uses are likely to have different efficiencies and therefore require different amounts of input energy. However, the graph shows that in 2025, it is expected that CCUS-enabled hydrogen is likely to have an emission factor less than half that of grid electricity. The graph also shows that the majority of CCUS-enabled emissions arise from the emissions associated with upstream natural gas supply.

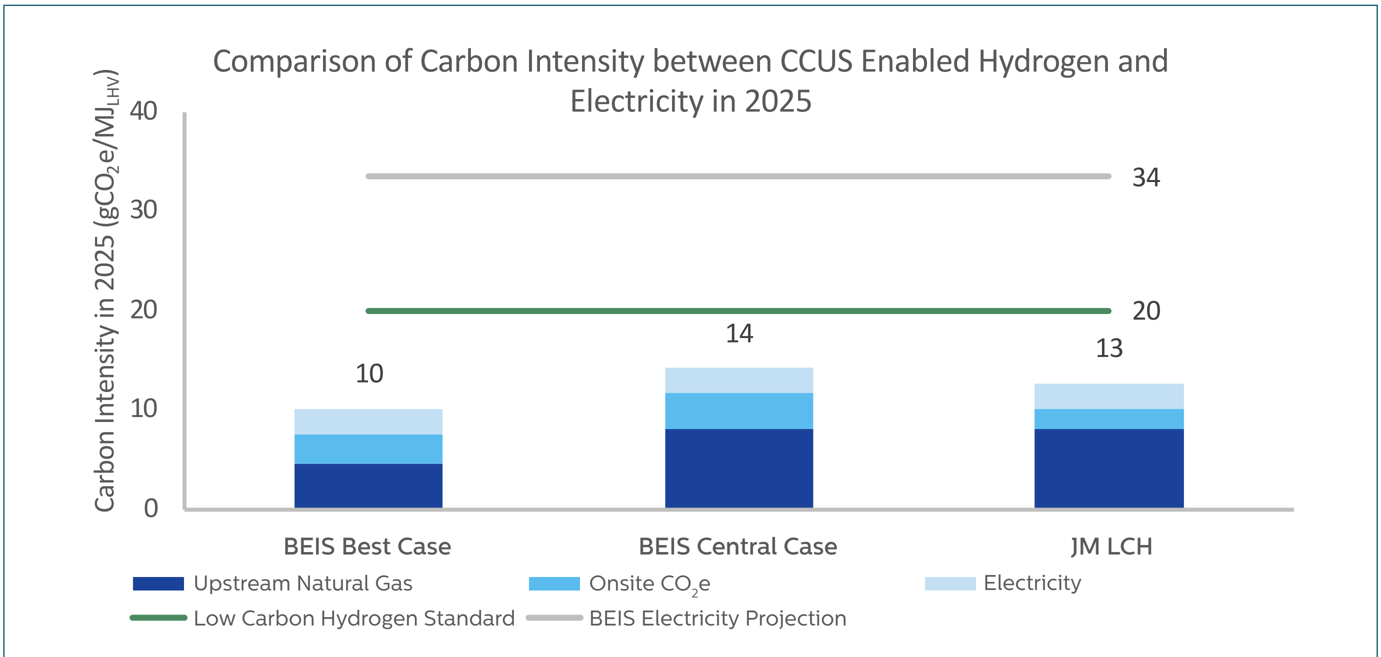


Figure 7: Comparison of Carbon Intensity between CCUS-Enabled Hydrogen and Electricity in 2025[35]

[i] 1gCO_2e/MJ = 3.6gCO_2e/kWh

[ii] Values used from version 1 of the Low Carbon Hydrogen Standard (LCHS) calculator. Due to an unresolved error within version 2 raised with DESNZ. Version 3 is expected to be published soon.

The emissions intensity of both grid electricity and hydrogen will reduce over time as upstream gas regulations are improved, curbing upstream fugitive methane emissions from the natural gas supply chain, and more low carbon electricity generation is deployed. It is expected that electricity will decarbonise at a faster rate than CCUS-enabled hydrogen production. However, with improving upstream natural gas regulation, the emissions associated with CCUS-enabled hydrogen can also be very low. If the UK can reduce upstream gas emissions to low levels comparable to Norway by 2030, **Figure 8**[iii] below shows that even in 2030 CCUS-enabled hydrogen would have much lower emissions than electricity.

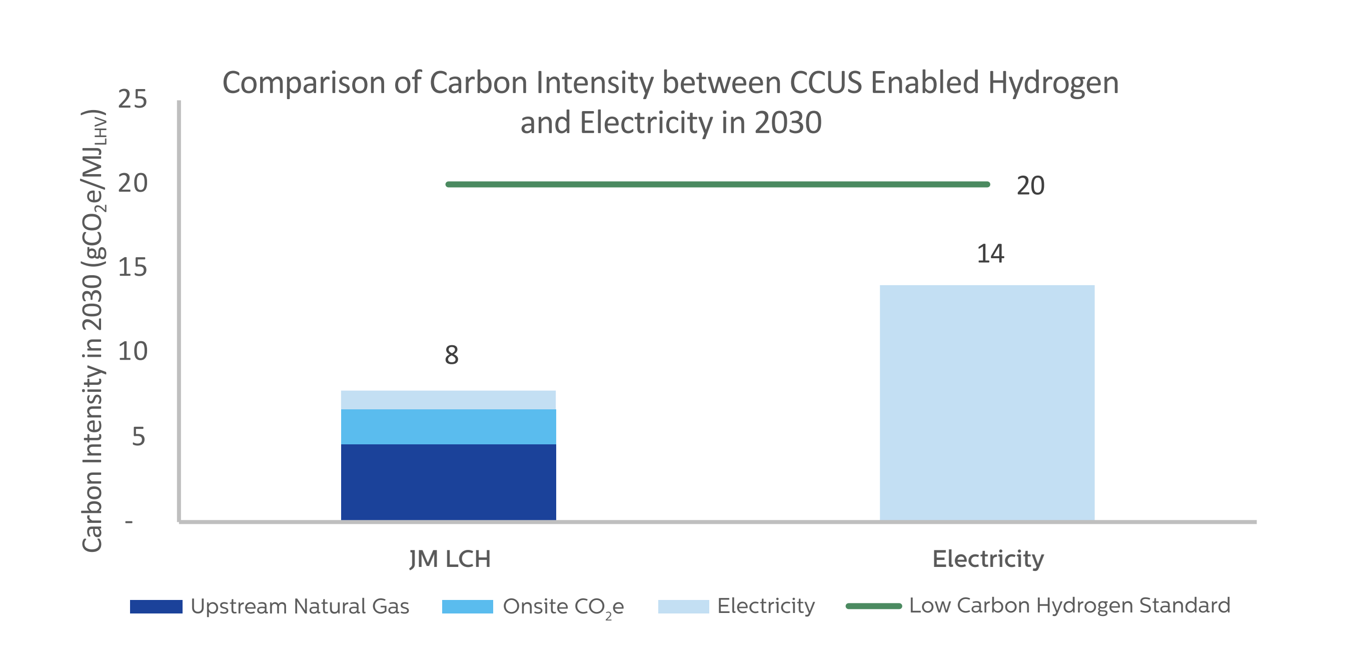


Figure 8: Comparison of carbon intensity between CCUS-enabled hydrogen and electricity in 2030 (DESNZ[34]) assuming improved methane leakage rates

Inevitably, electricity generation will have lower emissions than CCUS-enabled hydrogen from natural gas in the long term, as natural gas derived hydrogen will always have some residual emissions, unless produced with biomethane. However, the purpose of these graphs is to show that in the medium term CCUS-enabled hydrogen can deliver very significant emissions savings. In its recently published report, 'Delivering a Reliable Decarbonised Power System', the Committee on Climate Change stressed that: "Zero-carbon electricity must be prioritised for displacing unabated fossil generation and meeting increasing demands from electric vehicles and heat pumps"[36]. In order to decarbonise rapidly the UK will require a high degree of electrification, however CCUS-enabled hydrogen also has a significant role to play. A report by E4tech for BEIS (now DESNZ) which considers options for the Low Carbon Hydrogen Standard highlights how CCUS-enabled emissions can have considerable negative emissions. If using biomethane with ATR and CCS, the report estimates emissions to be approximately -60 gCO_2e/MJ H2 (LHV). Emissions are substantially lower if hydrogen is produced by wood gasification with CCS, which the report estimates to be approximately -160 gCO_2e/MJ H2 (LHV)[37].

[iii]Values used from version 1 of the Low Carbon Hydrogen Standard (LCHS) calculator. Due to an unresolved error within version 2 raised with DESNZ. Version 3 is expected to be published soon.

Time Value of Emissions

The social cost of carbon (SCC) is an estimate of the economic damage caused by emitting a tonne of carbon dioxide equivalent greenhouse gas emissions at a point in time. As concentrations of greenhouse gases in the atmosphere increase, each additional unit of emissions causes more damage than the last. This is reflected in the fact that SCCs tend to increase over time[38]. Therefore, carbon abatement now is worth more than carbon abatement in the future. CCUS-enabled hydrogen is one of the quickest ways to reduce emissions at scale in hard to decarbonise sectors.

In a similar way to the SCC, DESNZ produce carbon prices for policy appraisal. Instead of being based on the economic cost to society of the emissions, these are based on the Marginal Abatement Cost (MAC) of reducing emissions. **Figure 9** below shows this visually by showing DESNZ' carbon prices for policy evaluation[39] of carbon increasing over time. This shows that if a policy, such as deployment of CCUS-enabled hydrogen production, is beneficial using current carbon prices, it will be even more beneficial using future carbon prices.

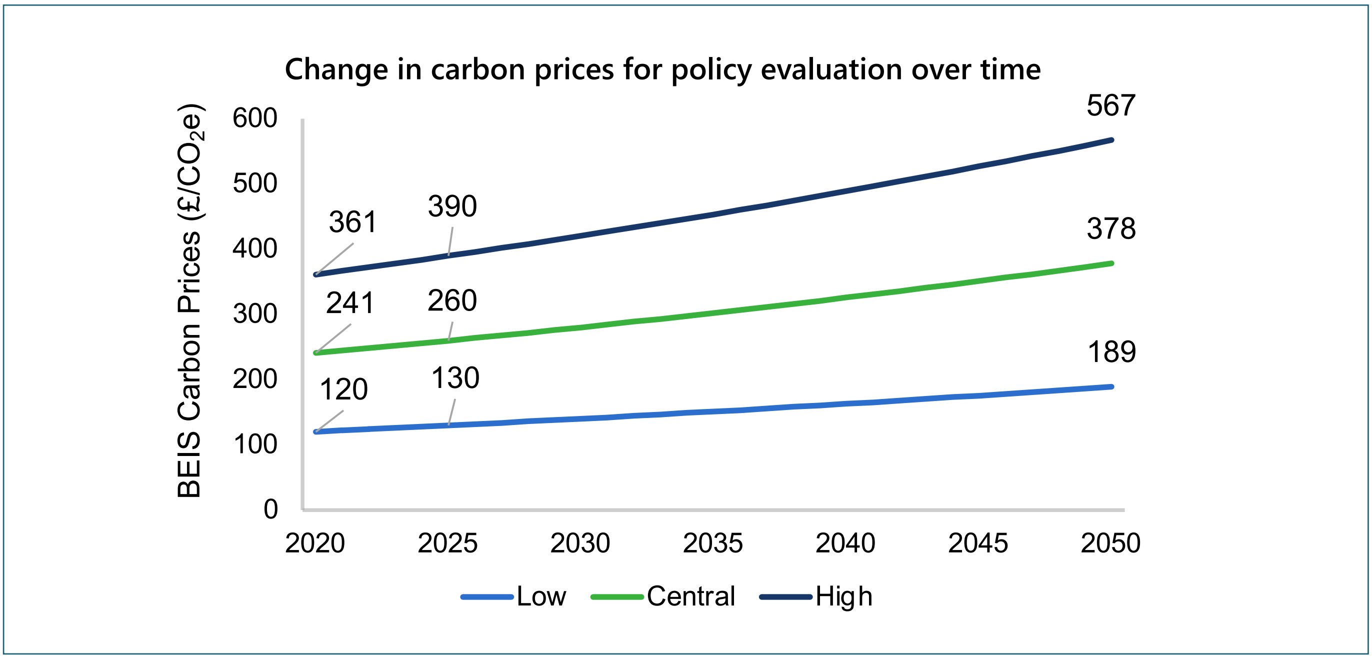


Figure 9: Change in carbon prices for policy evaluation over time[39].

Using the cost difference between natural gas and CCUS-enabled hydrogen from BEIS' Hydrogen Production Costs 2021, decarbonising natural gas costs approximately £33/MWh(LHV)[40]. Comparing the emissions when from moving from natural gas to hydrogen using BEIS' central CCUS-enabled emissions for 2025 of 51 gCO_2e/kWh(LHV)[34] and a natural gas emission factors of 237 gCO_2e/kWh(LHV)[41] implies an emission saving of 186 gCO_2e/kWh(LHV) when switching from natural gas to CCUS-enabled hydrogen. Combining these two figures gives an estimated cost of decarbonising natural gas of £177/tCO_2e. This is well below BEIS (now DESNZ) central carbon prices for policy appraisal in 2025 of £260/tCO_2e. For a complete comparison the costs of end use switching and any additional efficiency losses should be taken into account, however this shows that in scenarios with low fuel switching costs, switching from natural gas to CCUS-enabled hydrogen is effective value for money decarbonisation.

Addressing Criticisms of CCUS-Enabled Hydrogen Emissions

Several major news outlets have reported on an academic study titled 'How green is blue hydrogen?' which seeks to discredit the use of CCUS-enabled hydrogen. The study, which continues to receive media attention uses assumptions, some of which are implausible, to draw the conclusion that the life cycle greenhouse gas emissions from burning 'blue' hydrogen were more than 20% greater than emissions using conventional natural gas. As previously mentioned, CCUS-enabled hydrogen in the UK will need to meet the LCHS so will guarantee emission savings of at least 70% when switching from natural gas. The findings of the study are not applicable for CCUS-enabled hydrogen production in the UK for a wide range of reasons, including:

- **Assumed methane leakage rate of 3.5%** - the methane leakage rates in well-regulated markets such as the UK are much lower than this. As an example, the OGCI are targeting leakage rates well below 0.2% by 2025, already achieving this with 0.17% in 2021[42].
- **Assumed CO_2 capture rates of 85% and 65%** - ATRs with CCS should be able to achieve CO_2 capture rates above 90%; the CCC assume 95% and technology providers say 97%. SMR technology can also achieve capture rates of 90%.
- **Climate metric GWP20** – a GWP20 climate metric is used which ignores climate impacts beyond 20 years in the future. This puts a greater emphasis on methane emissions than CO_2 emissions which remain in the atmosphere far longer and coupled with the high methane leakage assumptions results in a very high emissions estimate for CCUS-enabled hydrogen.

A study produced by Equinor highlights the importance of good practice in the CCUS-enabled hydrogen production and explores emissions in more detail[43].

CCUS-Enabled Production in the UK

Hydrogen UK is compiling a database of all UK-based hydrogen projects that have been announced in the public domain. **Table 2** displays proposed production capacities, operational dates and peak capacity years. It must be noted that the entries in this section are project proposals, not production capacity.

Project Name	Location	Stage	Initial Prod. Capacity (MW)	Start Year	Peak Prod. Capacity (MW)	Peak Capacity Year
Acorn Hydrogen	Scotland	FEED	200	2026	TBC	TBC
H2Teesside (East Coast Cluster)	North East England	FEED	500	2027	1,000	2030
Humber Hub Blue Project	North East England	FEED	720	2027	720	2027
H2NorthEast (East Coast Cluster)	North East England	FEED (Q4 2023)	355	2028	1,000	2030
H2H Saltend (East Coast Cluster)	North East England	FEED	600	2027	600	2027
H2H Production 2	North East England	Concept	1,200	2028	1,200	2028
Acorn: Project Cavendish	South East England	Feasibility	700	2027	700	2027
Bacton Energy Hub	East England	Concept	355	2030	355	2030
South Wales Industrial Cluster	Wales	Concept	TBC	TBC	TBC	TBC
Southampton Hydrogen Hub (Solent Cluster)	South East England	Concept	1,000	TBC	2,000	TBC
Vertex Hydrogen HYNET	North West England	FEED	1,000	2026	4,000	2030
BOC Teeside Capture	North West England	FEED	150	2027	150	2027

Table 2: CCUS-Enabled Hydrogen Production Projects Data

Note: Dates and capacities are what have been stated publicly.

A key role CCUS-enabled hydrogen production has to play in the next few years is producing low carbon hydrogen at scale. **Figure 10** demonstrates how this production capacity increases from now until 2030, assuming all announced projects reach their maximum capacity at their stated operational date - only projects which have an operational date could be included in this figure. Furthermore, the government has framed the UK's hydrogen production targets as "up to 10 GW of low carbon hydrogen production by 2030, with at least half coming from electrolytic hydrogen" [44]. In Figure 10, we have assumed a 10 GW low carbon production target and a 5 GW electrolytic production target, however it's likely that this split may be different in 2030.

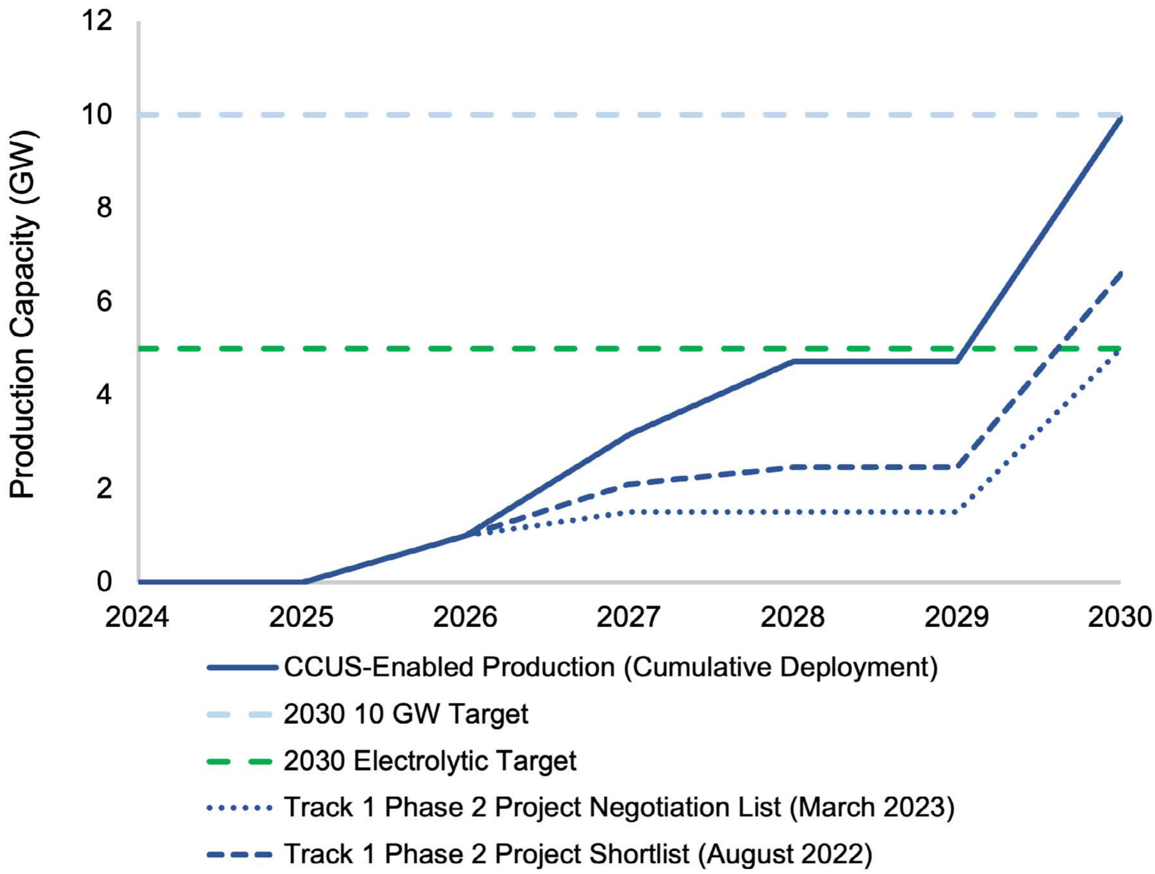


Figure 10: Cumulative CCUS-Enabled Hydrogen Production until 2030

Overview of the Cluster Sequencing Process

Background

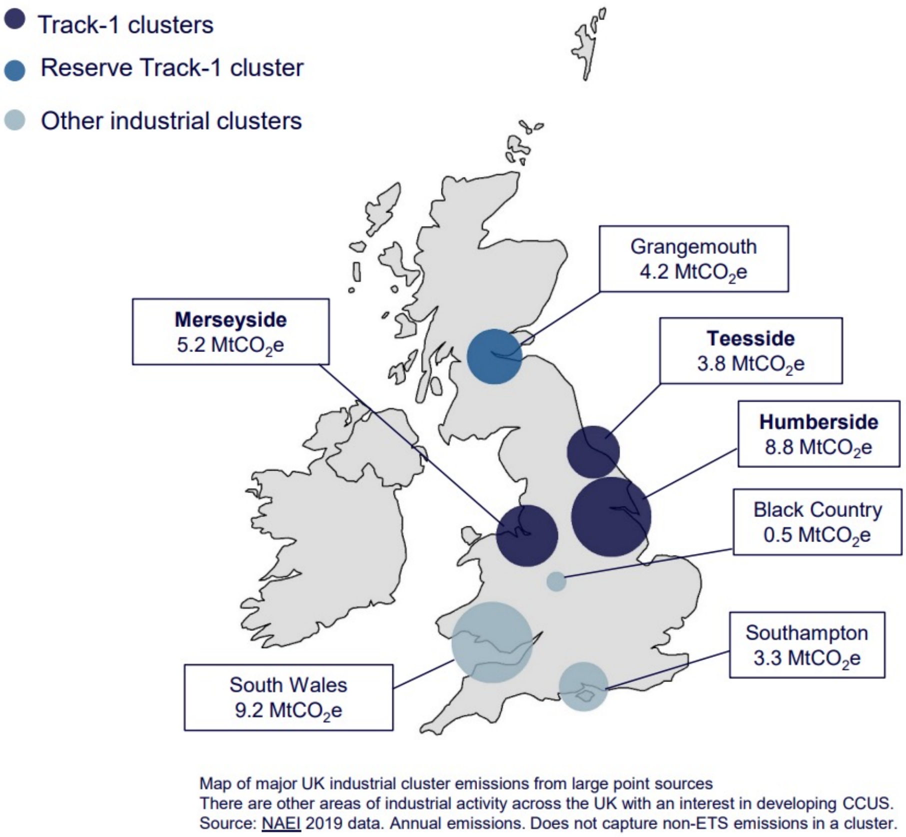


Figure 11: UK Industrial Cluster Map with Track-1 Status

Figure 11 shows the UK industrial clusters and their status within the Track-1 cluster sequencing process. On Energy Security Day (30th March 2023), DESNZ announced the Track-1 Phase 2 project negotiation list, containing just two hydrogen production projects. This announcement is the latest in the Track-1 cluster sequencing process, as demonstrated in **Figure 12** below[45].

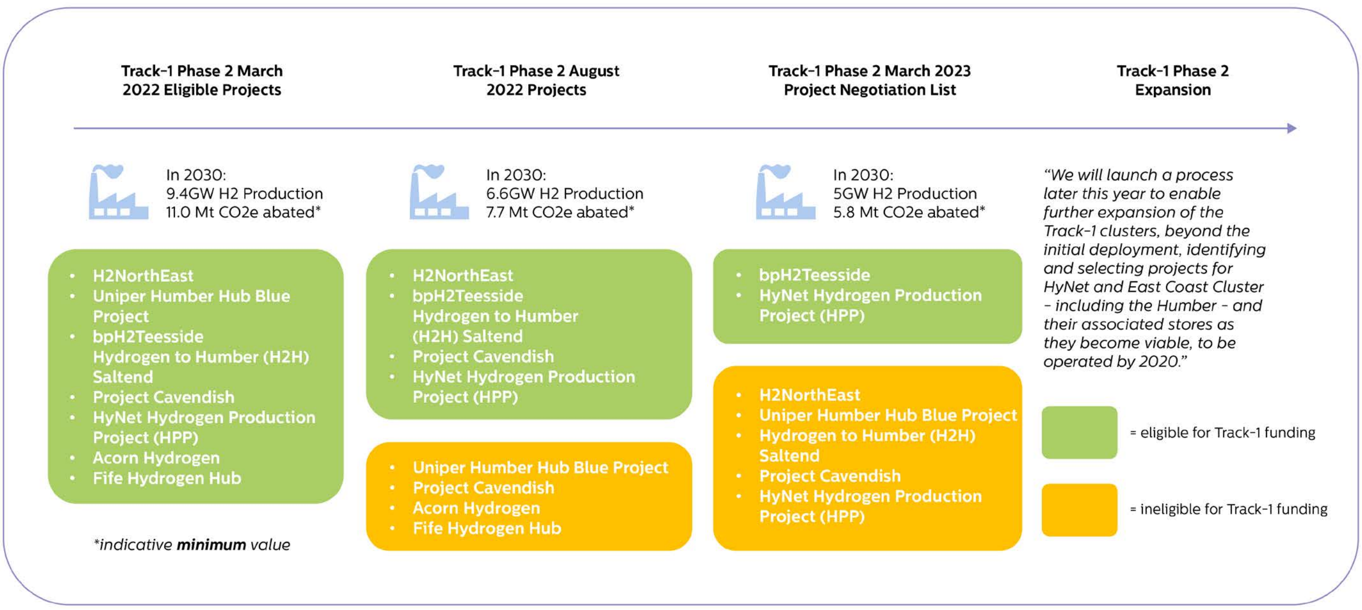


Figure 12: Track-1 Cluster Sequencing Process

Hydrogen UK

Concurrently, DESNZ invited Expression of Interest (EOI) submissions for Track-2 during April this year, aiming to select two clusters which can store at least 10 Mtpa of CO_2 by 2030. On 31st July, DESNZ confirmed that the Acorn and Viking CO_2 T&S systems, "due to their maturity, remain best placed to deliver our objectives for Track-2"and thus will commence engagement with both clusters.

Challenges

The cluster sequencing programme aims to enable the rollout of CCUS-enabled hydrogen within the UK. Pace and scale are needed to successfully achieve this. Hydrogen UK have ascertained some key challenges and learnings from the process so far on how to best accomplish this:

1. Investor Uncertainty

The phased nature of the rollout gives rise to a pertinent question – what happens to the projects not shortlisted? CCUS-enabled hydrogen developers face long lead times for planning, consenting, procurement and construction for their respective projects, meaning financial investment must be secured well in advance of any green light from government. To make investors and project developers consider waiting, a minimum level of certainty, in the form of timelines for projects both shortlisted and not, is urgently required. Without this basic level of detail, the level of uncertainty and confusion for the future can only be expected to cause investors to take their business elsewhere, losing the first mover advantage the UK has positioned itself in as a result of years of research, investment and project development. It is imperative that this minimum level of clarity is provided to industry.

2. Maximising Emissions Displaced

CCUS-enabled hydrogen projects have the capability to save million tonnes of carbon emissions from being released into the atmosphere and thus reducing the associated damaging environmental effects. As outlined in **Figure 13**, the Track-1 Phase-2 shortlisting process has gradually taken more and more CCUS-enabled hydrogen projects off the table, reducing the maximum potential level of carbon emissions that can be displaced within UK industrial clusters. Figure 13 displays the decrease in potential carbon emissions saved as a result of this shortlisting process.

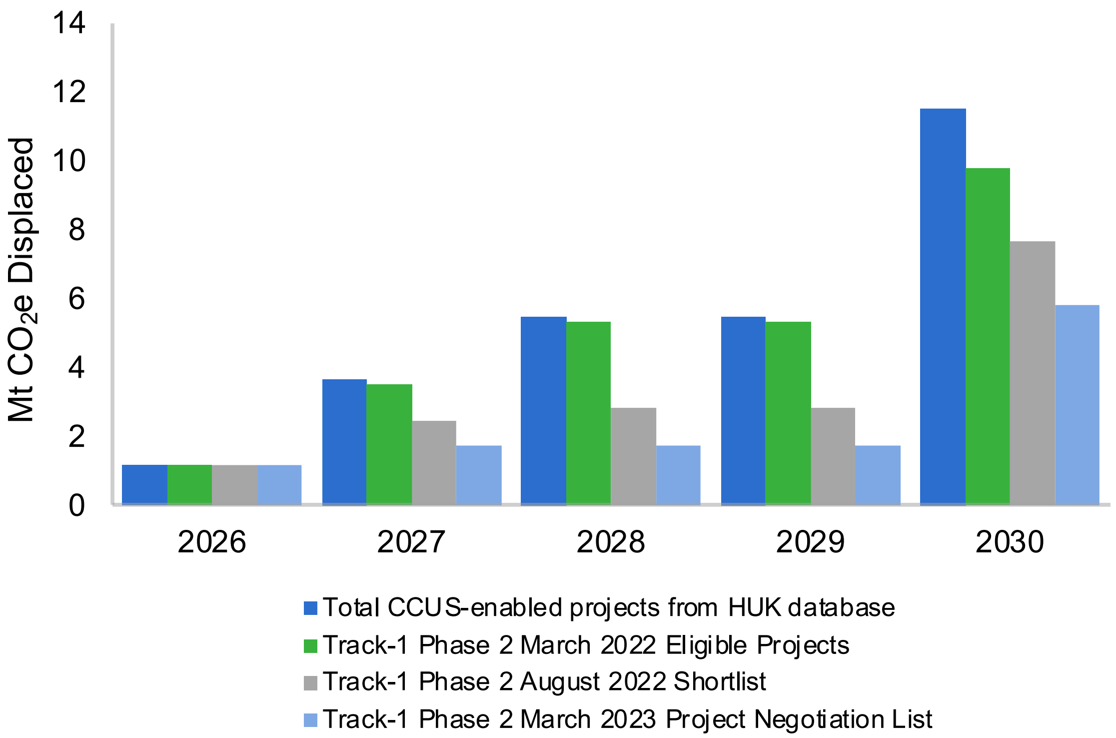


Figure 13: Indicative carbon emissions saved from CCUS-enabled hydrogen in clusters

It should be noted that the data displayed in figure 13 is a minimum indicative value of carbon emissions saved, due to the following assumptions:

- CCUS-enabled hydrogen is produced at the maximum emission intensity allowed under the LCHS up to 2030.

- The produced hydrogen only displaces methane from combustion applications, when other fuels and feedstocks with higher emission intensities will likely also be displaced.

Therefore, the savings missed out on will likely be considerably higher than those in Figure 13. Hydrogen UK acknowledges that there are further complexities to immediately funding all projects, however, recommends that the UK government provides a clear pathway for all cluster CCUS-enabled hydrogen production projects to be funded as quick as possible to maximize the associated environmental benefits.

3. *Ineffective Competition*

A major flaw of the cluster sequencing process is the overly competitive element it gives rise to. The competitive element requires developers to invest heavily without certainty over funding or timing. This points to the UK becoming a follower in deployment of CCUS technology, rather than a leader, especially when compared to other nations such as the United States. Here, initiatives such as the Inflation Reduction Act (IRA) and the Regional Clean Hydrogen Hubs Program encourage collaboration between a diverse range of stakeholders across the entire hydrogen value chain. In this environment, subsidies are provided for low carbon hydrogen production, storage and end-use applications, creating a fast moving, attractive landscape for CCUS-enabled hydrogen producers to locate their developments in. Comparing to the UK, it seems clear that the lack of collaboration between CCUS-enabled hydrogen production stakeholders will prove detrimental in the pace of rollout of the technology. It is vital that learnings and best practices are shared between industry to give the UK the best chance of developing into a world leading CCUS-enabled hydrogen nation and preventing international companies taking their business elsewhere.

In future, DESNZ should aim to reduce the level of ineffective competition from the cluster sequencing process, and instead focus on maximising carbon emissions at an acceptable value for money, by sharing learnings and fostering a more open environment.

4. *Carbon Dioxide Transport and Storage Requirements*

So far, a clear learning has been that the access CCUS-enabled projects have to CO_2 transport and storage infrastructure has proven to be critical in deciding which projects have been progressed. Only the four CCUS-enabled production projects which were listed on the August 2022 Phase-2 Cluster Sequencing shortlist have access to suitable CO_2 transport and storage infrastructure. This creates a portfolio risk for the remaining gaseous CCUS-enabled hydrogen production projects, currently with no visibility of the process for obtaining their necessary CO_2 transport and storage infrastructure connection or capacity. The Climate Change Committee's recent report 'Delivering a Reliable Decarbonised Power System' states "in the early days of its development blue hydrogen is likely to be located near a CCS sink to minimize the requirements for CO_2 transportation and storage"[46], highlighting the increased future requirements and potential bottlenecks for expansion away from already existing CO_2 infrastructure. To give some context to the CO_2 storage capacity required to meet the 2030 5GW CCUS-enabled[47] hydrogen production target, extrapolating the HyNet Low Carbon Hydrogen Plant performance data[51] gives a value of approximately 9 $MtCO_2$ pa.

As the implementation of transport and storage infrastructure comes with significant lead times, it is essential that direction is provided from the UK government on a strategy to connect non-shortlisted CCUS-enabled hydrogen production projects to either existing or new build CO_2 infrastructure, in turn providing the required confidence to investors and potential off-takers.

Case Studies

HyNet

Based in North West England and North Wales, the HyNet project is a successful Track-1 cluster that aims to become operational in 2025[48]. Within the project, hydrogen will be produced at the Stanlow Manufacturing Complex[49], operated by Vertex Hydrogen and transported around the cluster by the HyNet hydrogen network[50], developed by Cadent. HyNet partners INOVYN are repurposing salt caverns in the Northwich area of Cheshire to store 35,000 tonnes of hydrogen, providing security of supply. Beginning production in 2026, it will generate over 1GW of low carbon hydrogen, the equivalent to the energy used by a major British city region, for example Liverpool[51]. With the construction of a further three plants in the late 2020s, production capacity could increase to approximately 4GW, therefore playing a substantial role in helping to achieve the Government's 10 GW 2030 target. The resulting CO_2 captured at a target rate of 97% and a minimum rate of 95% by the CCUS-enabled hydrogen production process is to be stored underground in the nearby in the Liverpool Bay gas fields[52].

H2Teeside

bp is the lead operator of the East Coast Cluster, a group of projects including Net Zero Teesside and Zero Carbon Humber as part of the Northern Endurance Partnership (NEP)[53]. CCUS-enabled hydrogen production will provide c.160,000 tonnes of low carbon hydrogen per year. Furthermore, up to c.2million tonnes of CO_2 per year will be captured and sent to secure long-term storage – the equivalent of capturing the emissions from the heating of one million UK households[54]. The project aims to produce over 1GW of low carbon hydrogen production by 2030.

H2Teesside will supply hydrogen to a wide range of customers, including new businesses attracted to low carbon hydrogen produced at scale. The project will contribute towards levelling up due to the provision of high-quality jobs and upskilling opportunities. During construction, the project will support approximately 1200 jobs (both directly and indirectly) per year and approximately 600 jobs per year after the completion of phase 1 of the project.

Figure 14: H2Teesside Aerial View

Hydrogen UK

The Solent Cluster

The Solent Cluster, founded by ExxonMobil, Solent Local Enterprise Partnership and the University of Southampton, is a collaboration of cross-sector organisations, businesses and industries with expertise in CCUS. Currently emitting approximately 3.2 million tonnes of carbon dioxide emissions from manufacturing processes, the Solent Cluster is regarded as a leading contributor to total CO_2 release in the UK[55]. The project aims to capture up to 10 million tonnes of carbon dioxide per year, the equivalent of taking 3.75 million cars off the road[56]. The project will be anchored by the development of new hydrogen facilities at the existing Fawley petrochemical complex alongside the necessary CO_2 capture technology and associated transport and storage infrastructure.

Novel Technology Case Studies

HiiROC

HiiROC use Thermal Plasma Electrolysis (TPE) to produce hydrogen and carbon black from a hydrocarbon feedstock[57]. The TPE technology uses 4-5 times less energy than electrolysis of water for the same volume of hydrogen output. Carbon black is used in multiple commercial applications such as tyres, rubbers, inks and toners. The technology can be used from industrial scale (hundreds of tonnes/day) down to small modular units (hundred kg/day).

Figure 15: HiiROC Hydrogen Production Unit

Levidian

Levidian have developed a novel technology, named LOOP, that cracks methane into hydrogen and carbon, locking the carbon into high quality green graphene[58]. The LOOP system is modular and can be deployed readily on a customer site, integrating with existing infrastructure to deliver a hydrogen-rich gas blend for immediate use. LOOP can also produce separated hydrogen for use in a variety of applications. The graphene produced can then be utilised to decarbonise other materials. LOOP systems are operational in Levidian's Cambridge headquarters and in the UAE; further deployments are planned in the UK, Europe, and elsewhere this year.

Figure 16: Levidian Hydrogen Production Unit

Recommendations

1. Provide further clarity and certainty on the process and funding envelope for cluster sequencing.

Hydrogen UK welcomes the latest announcements from the UK Government on the cluster sequencing process, including the shortlisting of the Track-1 Phase-2 projects and the outcome of the Track 2 EOI process. We now call for DESNZ to provide further clarity and certainty to the funding and timelines for projects both in and out of Track-1 and expected Track-2 shortlists. The UK has an abundance of projects looking to help the decarbonisation effort; however, uncertainty and potentially unnecessary competition is creating a situation where the value for money of the projects could be adversely affected. Projects may be forced to factor in sub-optimal designs to account for the uncertainty in the sequencing, and therefore availability of large-scale shared infrastructure, and competition between the projects is limiting progress rather than helping to drive costs down. DESNZ must ensure that learnings from the evaluation of the Track-1 cluster sequencing process are fed into the design for the Track-2 process without further delay, including reviewing evaluation criteria weightings under an industry-agreed, consistent methodology.
It is essential that the UK maintains its early momentum in the CCUS-enabled production space, and that investment currently set aside for UK projects does not go elsewhere due to uncertainty and delays in an increasingly competitive global market.

2. The Heads of Terms for the HPBM must be fine-tuned to "break the chain of risk" for early movers.

With any nascent industry there exists the challenges and risks associated with reliability of supply and demand. For CCUS-enabled hydrogen production, this also extends to the availability of CO_2 transport and storage infrastructure, essential for ensuring the low carbon credentials of the produced hydrogen. In order to facilitate the realisation of early projects, it is necessary for Government to mitigate and break the chain of associated risks that are beyond the influence of hydrogen production projects, enabling them to concentrate on managing risks within their sphere of control. It is important to acknowledge that with the establishment of reliable infrastructure, the presence of multiple CO2 storage sites, the ability to blend hydrogen into gas networks, and a solid network of hydrogen consumers, these risks will fall away.

3. Ensure that novel technologies are supported in the Low Carbon Hydrogen Standard in advance of their commercial deployment.

The UK is home to the developers of several innovative hydrogen production technologies that deliver CCUS. However, they are 'not currently considered' within the LCHS. It is important that this stance is changed so that the deployment of these technologies is not hampered by inability to access government funding. In order to reach our Net Zero mandate, we will need every available technology, and delays to the deployment of technologies that can help decarbonise industrial emissions outside clusters must be avoided. In addition, the definition of CCUS by government should explicitly include production pathways that output solid carbon. This will remove the risk that rules and regulations relating to CCUS unwittingly exclude hydrogen production methods such as thermal plasma electrolysis and pyrolysis.

4. Provide clarity on CO_2 transport and storage infrastructure access for CCUS-enabled hydrogen production projects both inside and outside of industrial clusters

Gaseous CCUS-enabled production projects need access to the necessary CO_2 transport and storage infrastructure. Outside of the shortlisted Cluster Sequencing Phase-2 projects, CCUS-enabled production projects need visibility on how they will gain access to the necessary CO_2 transport and storage infrastructure connection and capacity. The UK government must provide clarity on this process to ensure there is no lag period where CCUS-enabled production projects are not able to operate due to a lack of access to CO_2 transport and storage infrastructure, and to provide the necessary confidence for projects to move ahead with current timelines.

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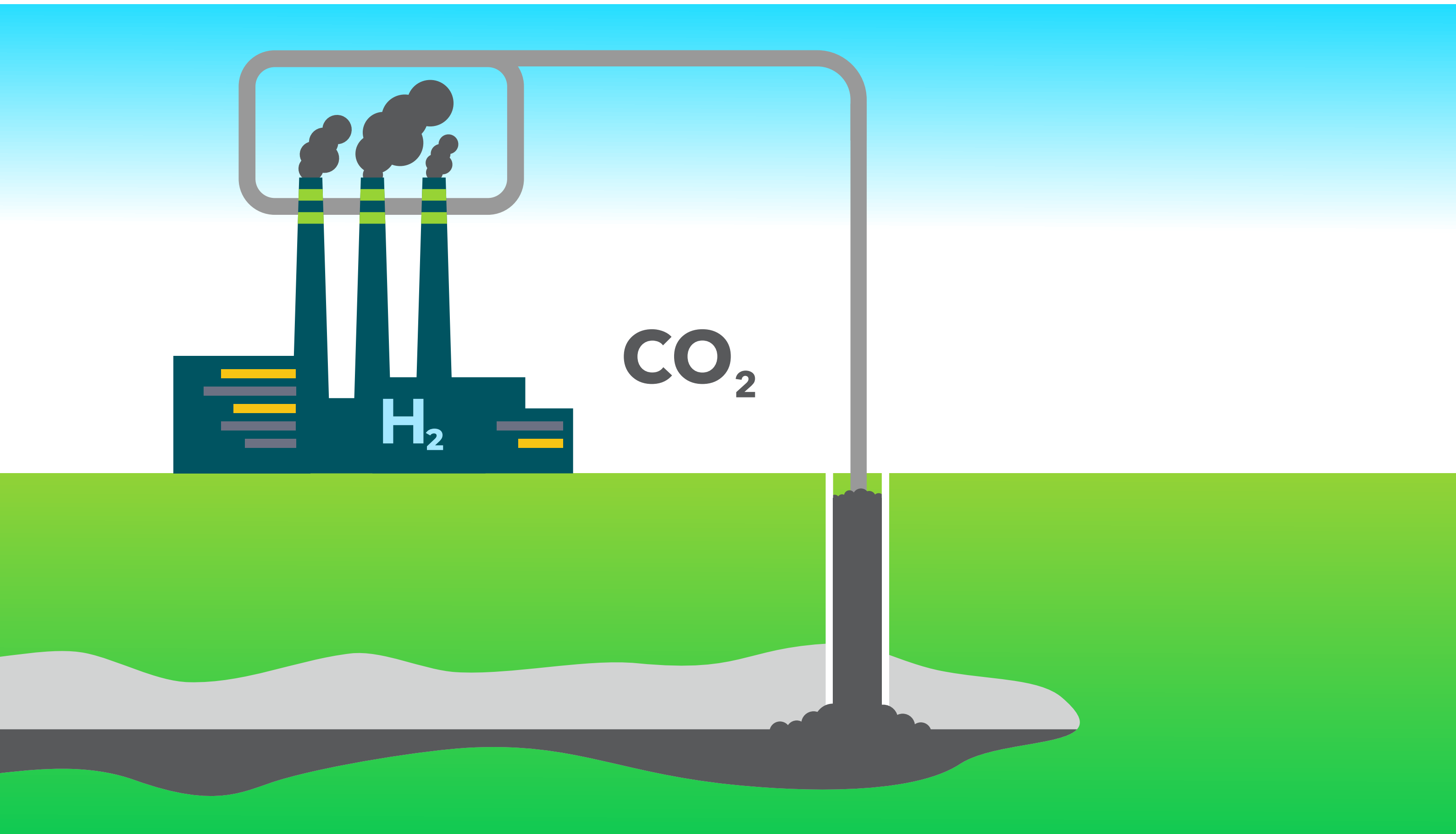

APPENDIX 3 GLOBAL HYDROGEN REVIEW 2021

Global Hydrogen Review 2021

INTERNATIONAL ENERGY AGENCY

The IEA examines the full spectrum of energy issues including oil, gas and coal supply and demand, renewable energy technologies, electricity markets, energy efficiency, access to energy, demand side management and much more. Through its work, the IEA advocates policies that will enhance the reliability, affordability and sustainability of energy in its 30 member countries, 8 association countries and beyond.

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Executive Summary

After several false starts, a new beginning around the corner

The time is ripe to tap into hydrogen's potential contribution to a sustainable energy system. In 2019, at the time of the release of the IEA's landmark report The Future of Hydrogen for the G20, only France, Japan and Korea had strategies for the use of hydrogen. Today, 17 governments have released hydrogen strategies, more than 20 governments have publicly announced they are working to develop strategies, and numerous companies are seeking to tap into hydrogen business opportunities. Such efforts are timely: hydrogen will be needed for an energy system with net zero emissions. In the IEA's Net Zero by 2050: A Roadmap for the Global Energy Sector, hydrogen use extends to several parts of the energy sector and grows sixfold from today's levels to meet 10% of total final energy consumption by 2050. This is all supplied from low-carbon sources.

Hydrogen supplies are becoming cleaner … too slowly

Hydrogen demand stood at 90 Mt in 2020, practically all for refining and industrial applications and produced almost exclusively from fossil fuels, resulting in close to 900 Mt of CO_2 emissions. But there are encouraging signs of progress. Global capacity of electrolysers, which are needed to produce hydrogen from electricity, doubled over the last five years to reach just over 300 MW by mid-2021. Around 350 projects currently under development could bring global capacity up to 54 GW by 2030. Another 40 projects accounting for more than 35 GW of capacity are in early stages of development. If all those projects are realised, global hydrogen supply from electrolysers could reach more than 8 Mt by 2030. While significant, this is still well below the 80 Mt required by that year in the pathway to net zero CO_2 emissions by 2050 set out in the IEA Roadmap for the Global Energy Sector.

Europe is leading electrolyser capacity deployment, with 40% of global installed capacity, and is set to remain the largest market in the near term on the back of the ambitious hydrogen strategies of the European Union and the United Kingdom. Australia's plans suggest it could catch up with Europe in a few years; Latin America and the Middle East are expected to deploy large amounts of capacity as well, in particular for export. The People's Republic of China ("China") made a slow start, but its number of project announcements is growing fast, and the United States is stepping up ambitions with its recently announced Hydrogen Earthshot.

Sixteen projects for producing hydrogen from fossil fuels with carbon capture, utilisation and storage (CCUS) are operational today, producing 0.7 Mt of hydrogen annually. Another 50 projects are under development and, if realised, could increase the annual hydrogen production to more than 9 Mt by 2030. Canada and the United States lead in the production of hydrogen from fossil fuels with CCUS, with more than 80% of global capacity production, although the United

Kingdom and the Netherlands are pushing to become leaders in the field and account for a major part of the projects under development.

Expanding the reach of hydrogen use

Hydrogen can be used in many more applications than those common today. Although this still accounts for a small share of total hydrogen demand, recent progress to expand its reach has been strong, particularly in transport. The cost of automotive fuel cells has fallen by 70% since 2008 thanks to technological progress and growing sales of fuel cell electric vehicles (FCEVs). Thanks to the efforts by Korea, the Unites States, China and Japan, the number of FCEVs on the road grew more than sixfold from 7 000 in 2017 to over 43 000 by mid-2021. In 2017, practically all FCEVs were passenger cars. Today, one-fifth are buses and trucks, indicating a shift to the long-distance segment where hydrogen can better compete with electric vehicles. However, the total number of FCEVs is still well below the estimated 11 million electric vehicles on the road today. Several demonstration projects for the use of hydrogen-based fuels in rail, shipping and aviation are already under development and are expected to open new opportunities for creating hydrogen demand.

Hydrogen is a key pillar of decarbonisation for industry, although most of the technologies that can contribute significantly are still nascent. Major steps are being taken. The world's first pilot project for producing carbon-free steel using low-carbon hydrogen began operation this year in Sweden. In Spain, a pilot project for the use of variable renewables-based hydrogen for ammonia production will start at the end of 2021. Several projects at a scale of tens of kilotonnes of hydrogen are expected to become operational over the next two to three years. Demonstration projects for using hydrogen in industrial applications such as cement, ceramics or glass manufacturing are also under development.

Governments need to scale up ambitions and support demand creation

Countries that have adopted hydrogen strategies have committed at least USD 37 billion; the private sector has announced an additional investment of USD 300 billion. But putting the hydrogen sector on track for net zero emissions by 2050 requires USD 1 200 billion of investment in low-carbon hydrogen supply and use through to 2030.

The focus of most government policies is on producing low-carbon hydrogen. Measures to increase demand are receiving less attention. Japan, Korea, France and the Netherlands have adopted targets for FCEV deployment. But boosting the role of low-carbon hydrogen in clean energy transitions requires a step change in demand creation. Governments are starting to announce a wide variety of policy instruments, including carbon prices, auctions, quotas, mandates and requirements in public procurement. Most of these measures have not yet entered into force. Their quick and widespread enactment could unlock more projects to scale up hydrogen demand.

Low-carbon hydrogen can become competitive within the next decade

A key barrier for low-carbon hydrogen is the cost gap with hydrogen from unabated fossil fuels. At present, producing hydrogen from fossil fuels is the cheapest option in most parts of the world. Depending on regional gas prices, the levelised cost of hydrogen production from natural gas ranges from USD 0.5 to USD 1.7 per kilogramme (kg). Using CCUS technologies to reduce the CO_2 emissions from hydrogen production increases the levelised cost of production to around USD 1 to USD 2 per kg. Using renewable electricity to produce hydrogen costs USD 3 to USD 8 per kg.

There is significant scope for cutting production costs through technology innovation and increased deployment. The potential is reflected in the IEA's *Net Zero Emissions by 2050 Scenario* (NZE Scenario) in which hydrogen from renewables falls to as low as USD 1.3 per kg by 2030 in regions with excellent renewable resources (range USD 1.3-3.5 per kg), comparable with the cost of hydrogen from natural gas with CCUS. In the longer term, hydrogen costs from renewable electricity fall as low as USD 1 per kg (range USD 1.0-3.0 per kg) in the NZE Scenario, making hydrogen from solar PV cost-competitive with hydrogen from natural gas even without CCUS in several regions.

Meeting climate pledges requires faster and more decisive action

While the adoption of hydrogen as a clean fuel is accelerating, it still falls short of what is required to help reach net zero emissions by 2050. If all the announced industrial plans are realised, by 2030:

- Total hydrogen demand could grow as high as 105 Mt – compared with more than 200 Mt in the NZE Scenario
- Low-carbon hydrogen production could reach more than 17 Mt – one-eighth of the production level required in the NZE Scenario
- Electrolysis capacity could rise to 90 GW – well below the nearly 850 GW in the NZE Scenario
- Up to 6 million FCEVs could be deployed – 40% of the level of deployment in the NZE Scenario (15 million FCEVs)

Much faster adoption of low-carbon hydrogen is needed to put the world on track for a sustainable energy system by 2050. Developing a global hydrogen market can help countries with limited domestic supply potential while providing export opportunities for countries with large renewable or CO_2 storage potential. There is also a need to accelerate technology innovation efforts. Several critical hydrogen technologies today are in early stages of development. We estimate that USD 90 billion of public money needs to be channeled into clean energy innovation worldwide as quickly as possible – with around half of it dedicated to hydrogen-related technologies.

Stronger international co-operation: a key lever for success

International co-operation is critical to accelerate the adoption of hydrogen. Japan has spearheaded developments through the Hydrogen Energy Ministerial Meeting since 2018. Several bilateral and multilateral co-operation agreements and initiatives have since been announced, including the Clean Energy Ministerial Hydrogen Initiative, the Hydrogen Mission of Mission Innovation and the Global Partnership for Hydrogen of the United Nations Industrial Development Organization. These join the existing International Partnership for Hydrogen and Fuel Cells in the Economy and the IEA Hydrogen and Advanced Fuel Cells Technology Collaboration Programme. Stronger coordination among such initiatives is important to avoid duplication of efforts and ensure efficient progress.

IEA policy recommendations

Governments must take a lead in the energy transformation. In The Future of Hydrogen, the IEA identified a series of recommendations for near-term action. This report offers more detail about how policies can accelerate the adoption of hydrogen as a clean fuel:

- **Develop strategies and roadmaps on the role of hydrogen in energy systems**: National hydrogen strategies and roadmaps with concrete targets for deploying low-carbon production and, particularly, stimulating significant demand are critical to build stakeholder confidence about the potential market for low-carbon hydrogen. This is a vital first step to create momentum and trigger more investments to scale up and accelerate deployment.
- **Create incentives for using low-carbon hydrogen to displace unabated fossil fuels**: Demand creation is lagging behind what is needed to help put the world on track to reach net-zero emissions by 2030. It is critical to increase concrete measures on this front to tap into hydrogen's full potential as a clean energy vector. Currently, low-carbon hydrogen is more costly to use than unabated fossil-based hydrogen in areas where hydrogen is already being employed – and it is more costly to use than fossil fuels in areas where hydrogen could eventually replace them. Some countries are already using carbon pricing to close this cost gap but this is not enough. Wider adoption combined with other policy instruments like auctions, mandates, quotas and hydrogen requirements in public procurement can help de-risk investments and improve the economic feasibility of low-carbon hydrogen.
- **Mobilise investment in production, infrastructure and factories**: A policy framework that stimulates demand can, in turn, prompt investment in low-carbon production plants, infrastructure and manufacturing capacity. However, without stronger policy action, this process will not happen at the necessary pace to meet climate goals. Providing tailor-made support to selected shovel-ready flagship projects can kick-start the scaling up of low-carbon hydrogen and the development of infrastructure to connect supply sources to demand centres and manufacturing capacities from which later projects can benefit. Adequate infrastructure planning is critical to avoid delays or the creation of assets that can become stranded in the near or medium term.
- **Provide strong innovation support to ensure critical technologies reach commercialisation soon**: Continuous innovation is essential to drive down costs and increase the competitiveness of hydrogen technologies. Unlocking the full potential demand for hydrogen will require strong demonstration efforts over the next decade. An increase of R&D budgets and support for demonstration projects is urgently needed to make sure key hydrogen technologies reach commercialisation as soon as possible.
- **Establish appropriate certification, standardisation and regulation regimes**: The adoption of hydrogen will spawn new value chains. This will require modifying current regulatory frameworks and defining new standards and certification schemes to remove barriers preventing widespread adoption. International agreement on methodology to calculate the carbon footprint of hydrogen production is particularly important to ensure that hydrogen production is truly low-carbon. It will also play a fundamental role in developing a global hydrogen market.

Introduction

Overview

In the run-up to the 26th Conference of the Parties to the UN Framework Convention on Climate Change (COP 26), a growing number of countries are announcing targets to achieve net zero GHG emissions over the next decades. In turn, more than 100 companies that consume large volumes of energy or produce energy-consuming goods have followed suit. As demonstrated in the IEA Net zero by 2050 roadmap, achieving these targets will require immediate action to turn the 2020s into a decade of massive clean energy expansion.

Hydrogen will need to play an important role in the transition to net zero emissions. Since the first Hydrogen Energy Ministerial (HEM) meeting in Japan in 2018, momentum has grown and an increasing number of governments and companies are establishing visions and plans for hydrogen.

At the Osaka Summit in 2019, G20 leaders emphasised hydrogen's role in enabling the clean energy transition. The IEA prepared the landmark report The Future of Hydrogen for the summit, with detailed analysis of the state of hydrogen technologies and their potential to contribute to energy system transformation, as well as challenges that need to be overcome. In addition, during the 10th Clean Energy Ministerial (CEM) meeting in Vancouver, the Hydrogen Initiative (H2I) was launched to accelerate hydrogen deployment, and during the 6th Mission Innovation Ministerial, the Clean Hydrogen Mission to reduce the cost of clean hydrogen was announced.

This Global Hydrogen Review is an output of H2I that is intended to inform energy sector stakeholders on the current status and future prospects of hydrogen and serve as an input to the discussions at the HEM of Japan. It comprehensively examines what is needed to address climate change and compares actual progress with stated government and industry ambitions and with key actions announced in the Global Action Agenda launched in the HEM 2019. Focusing on hydrogen's usefulness in meeting climate goals, this Review aims to help decision makers fine-tune strategies to attract investment and facilitate deployment of hydrogen technologies while also creating demand for hydrogen and hydrogen-based fuels.

This Review's analysis comprises seven chapters. First, the chapter on **policy trends** describes progress made by governments in adopting hydrogen-related policies. Next, two comprehensive chapters on **global hydrogen demand** and **supply** provide in-depth analyses of recent advances in different sectors and technologies and explore how trends could evolve in the medium and long term.

A chapter on **infrastructure and hydrogen trade** emphasises the need to develop both these areas while ramping up demand and supply. It also details the status and opportunities for deploying hydrogen infrastructure, as well as recent trends and the outlook for hydrogen trade.

Investments and innovation are combined into one chapter to reflect how they mutually underpin trends in the development and uptake of hydrogen technologies. Meanwhile, the chapter on **insights on selected regions** recaps progress in regions and countries where governments and industry are particularly active in advancing hydrogen deployment.

The final chapter provides **policy recommendations** to accelerate the adoption of hydrogen technologies in the next decade, with a view to ensuring it becomes economically and technically viable and socially acceptable.

The Hydrogen Initiative

Developed under the CEM framework, H2I is a voluntary multi-government initiative that aims to advance policies, programmes and projects that accelerate the commercialisation and deployment of hydrogen and fuel cell technologies across all areas of the economy. Ultimately, it seeks to ensure hydrogen's place as a key enabler in the global clean energy transition.

The IEA serves as the H2I co-ordinator to support member governments as they develop activities aligned with the initiative. H2I currently comprises the following participating governments and intergovernmental entities: Australia, Austria, Brazil, Canada, Chile, the People's Republic of China (hereafter China), Costa Rica, the European Commission, Finland, Germany, India, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, the Republic of Korea (hereafter Korea), the Russian Federation (hereafter Russia), Saudi Arabia, South Africa, the United Kingdom and the United States. Canada, the European Commission, Japan, the Netherlands and the United States co-lead the initiative, while China and Italy are observers.

HYDROGEN INITIATIVE

AN INITIATIVE OF THE CLEAN ENERGY MINISTERIAL

H2I is also a platform to co-ordinate and facilitate co-operation among governments, other international initiatives and the industry sector. The Initiative has active partnerships with the Hydrogen Council, the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE), the International Renewable Energy Agency (IRENA), Mission Innovation (MI), the World Economic Forum (WEF) and the IEA's Advanced Fuel Cells and Hydrogen Technology Collaboration Programmes (TCPs), all of which are part of the H2I Advisory Group. In addition, several industrial partners actively participate in the H2I Advisory Group's bi-annual meetings, including Ballard, Enel, Engie, Nel Hydrogen, the Port of Rotterdam and Thyssenkrupp.

The Global Hydrogen Review

Following IEA recommendations in The Future of Hydrogen, this Global Hydrogen Review aims to track progress in hydrogen production and demand, as well as in other areas of critical importance such as policy, regulation and infrastructure development. To do this effectively and comprehensively, the IEA has established co-operative relationships with other relevant institutions to provide sound analysis based on the best possible data, and to create synergies among other international efforts, building on their respective strengths and experiences.

The Hydrogen Council in particular shared critical information on technology costs and performance from its industry network, which enriched IEA databases, modelling assumptions and techno-economic parameters.

Meanwhile, the IPHE contributed inputs on the developmental status of standards, codes and regulations. Leveraging its government network and established process to collect data and work collaboratively on regulatory issues, it also provided valuable information on the technology deployment and policy targets of its member governments.

The IEA TCPs and their networks of researchers and stakeholders also provided valuable inputs. The Hydrogen TCP helped the IEA update its latest assessment of the technology readiness levels of specific hydrogen technologies and offered insights on emerging technologies and barriers that need to be overcome to facilitate their deployment. The Advanced Fuel Cells TCP contributed with its annual tracking of fuel cell electric vehicles and infrastructure deployment.

Types of hydrogen in the Global Hydrogen Review

Hydrogen is a very versatile fuel that can be produced using all types of energy sources (coal, oil, natural gas, biomass, renewables and nuclear) through a very wide variety of technologies (reforming, gasification, electrolysis, pyrolysis, water splitting and many others). In recent years, colours have been used to refer to different hydrogen production routes (e.g. green for hydrogen from renewables and blue for production from natural gas with carbon capture, utilisation and storage [CCUS]), and specialised terms currently under discussion include “safe”, “sustainable”, “low-carbon” and “clean”. There is no international agreement on the use of these terms as yet, nor have their meanings in this context been clearly defined.

Because of the various energy sources that can be used, the environmental impacts of each production route can vary considerably; plus, the geographic region and the process configuration applied also influence impacts. For these reasons, the

IEA does not specifically espouse any of the above terms. Recognising that the potential of hydrogen to reduce CO_2 emissions depends strongly on how it is produced, this report highlights the role low-carbon hydrogen production routes can have in the clean energy transition. Low-carbon hydrogen in this report includes hydrogen produced from renewable and nuclear electricity, biomass, and fossil fuels with CCUS.[1]

Production from fossil fuels with CCUS is included only if upstream emissions are sufficiently low, if capture – at high rates – is applied to all CO_2 streams associated with the production route, and if all CO_2 is permanently stored to prevent its release into the atmosphere. The same principle applies to low-carbon feedstocks and hydrogen-based fuels made using low-carbon hydrogen and a sustainable carbon source (of biogenic origin or directly captured from the atmosphere).

This report also highlights the importance of establishing standards and certification to properly recognise the carbon footprints of the different hydrogen production routes. Since no standards have been internationally agreed and adopted, the IEA continues to differentiate the types of hydrogen by the technology used in their production, and uses this as the basis of its current definition of low-carbon hydrogen. This may evolve as dialogue within the international hydrogen community advances and more evidence and agreement emerge.

[1] In this report, CCUS includes CO_2 captured for use (CCU) as well as for storage (CCS), including CO_2 that is both used and stored (e.g. for enhanced oil recovery [EOR] or building materials) if some or all of the CO_2 is permanently stored. When use of the CO_2 ultimately leads to it being re-emitted to the atmosphere (e.g. urea production), CCU is specified.

Scenarios used in this Global Hydrogen Review

Outlook for hydrogen production and use

This Global Hydrogen Review relies on three indicators to track progress on hydrogen production and use:

- on-the-ground progress in hydrogen technology deployment
- government ambitions to integrate hydrogen into long-term energy strategies
- gaps between on-the-ground progress, government ambitions and projected energy transition requirements.

In this report, the Projects Case reflects on-the-ground progress. It takes all projects in the pipeline[2] into account as well as announced industry stakeholder plans to deploy hydrogen technologies across the entire value chain (from production to use in different end-use sectors).

Government targets and ambitions related to deploying hydrogen technologies are presented as hydrogen pledges. To gather relevant information from governments around the world, a joint IEA–European Commission work stream was established within the framework of the CEM Hydrogen Initiative, to consult governments around the world about their hydrogen targets and ambitions.

Pledges presented in this report include official targets (i.e. clear goals of national hydrogen strategies and roadmaps) as well as ambitions (i.e. plans communicated in consultations through the H2I work stream, but for which governments have not yet made official announcements or adopted a strategy or roadmap).

For the first time, the IEA's May 2021 report Net zero by 2050 lays out in detail what is needed from the energy sector to reach net zero CO_2 emissions by 2050, in line with the Paris Agreement's ambitious target to limit global temperature rise to 1.5°C. Based on these findings, this Review compares actual implemented actions with clean energy transition needs using two IEA scenarios: the Net zero Emissions by 2050 Scenario and the Announced Pledges Scenario.

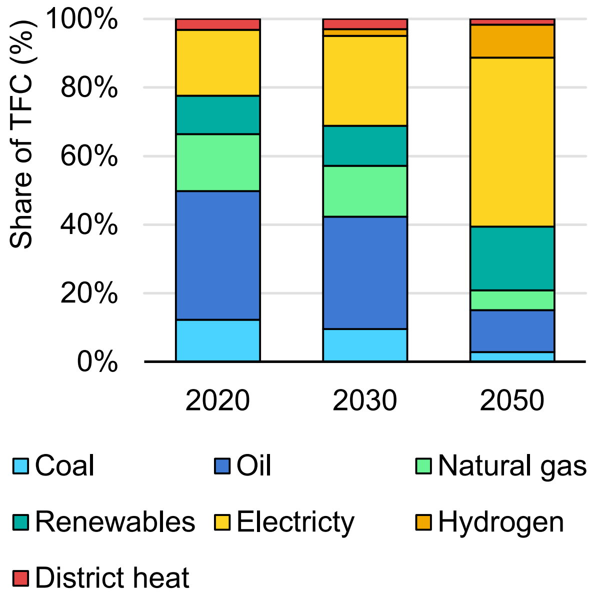
The Announced Pledges Scenario considers all national net zero emissions pledges that governments have announced to date and assumes they are realised in full and on time. This scenario thereby shows how far full implementation of national net zero emissions pledges would take the world towards reaching climate goals, and it highlights the potential contributions of different technologies, including hydrogen.

[2] In addition to projects already operational, this includes those currently under construction, that have reached final investment decision (FID) and that are undergoing feasibility studies.

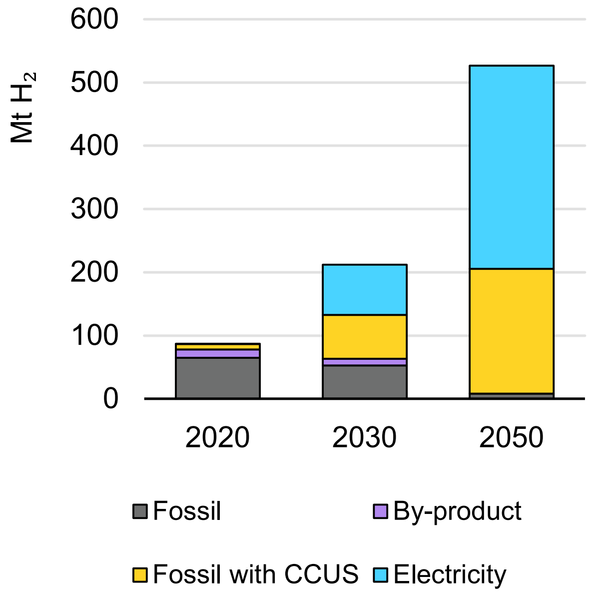
The role of hydrogen in the Net zero Emissions by 2050 Scenario

Hydrogen is an important part of the Net zero Emissions Scenario, but is only one piece of the puzzle

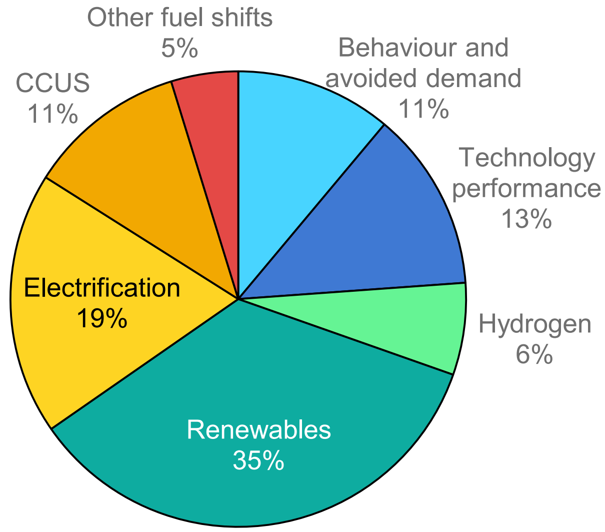
Share of total final energy consumption by fuel in the NZE, 2020-2050



Sources of hydrogen production in the NZE, 2020-2050



Cumulative emissions reduction by mitigation measure in the NZE, 2021-2050



Notes: NZE = Net zero Emissions Scenario. TFC = total final energy consumption. CCUS = carbon capture, utilisation and storage. “Behaviour” refers to energy service demand changes linked to user decisions (e.g. heating temperature changes). “Avoided demand” refers to energy service demand changes from technology developments (e.g. digitalisation). “Other fuel shifts” refers to switching from coal and oil to natural gas, nuclear, hydropower, geothermal, concentrating solar power or marine energy. “Hydrogen” includes hydrogen and hydrogen-based fuels.

Source: IEA (2021), Net zero by 2050.

Achieving net zero emissions by 2050 will require a broad range of technologies to transform the energy system. The key pillars of decarbonising the global energy system are energy efficiency, behavioural change, electrification, renewables, hydrogen and hydrogen-based fuels, and CCUS. The importance of hydrogen in the Net zero Emissions Scenario is reflected in its increasing share in total final energy consumption (TFC): in 2020, hydrogen and hydrogen-based fuels accounted for less than 0.1%,[3] but by 2030 they meet 2% of TFC and in 2050, 10%.

Nevertheless, this demand increase alone is not enough to make hydrogen a key pillar of decarbonisation. Hydrogen production must also become much cleaner than it is today. For instance, of the ~90 Mt H_2 used in 2020, around 80% was produced from fossil fuels, mostly unabated. Practically all the remainder came from residual gases produced in refineries and the petrochemical industry. This resulted in almost 900 Mt CO_2 emitted in the production of hydrogen, equivalent to the CO_2 emissions of Indonesia and the United Kingdom combined.

In the Net zero Emissions Scenario, hydrogen production undergoes an unparalleled transformation. By 2030, when total production reaches more than 200 Mt H_2, 70% is produced using low-carbon technologies (electrolysis or fossil fuels with CCUS). Hydrogen production then grows to over 500 Mt H_2 by 2050, practically all based on low-carbon technologies. Reaching these goals will require that installed electrolysis capacity increase from 0.3 GW today to close to 850 GW by 2030 and almost 3 600 GW by 2050, while CO_2 captured in hydrogen production must rise from 135 Mt today to 680 Mt in 2030 and 1 800 Mt in 2050.

Strong hydrogen demand growth and the adoption of cleaner technologies for its production thus enable hydrogen and hydrogen-based fuels to avoid up to 60 Gt CO_2 emissions in 2021-2050 in the Net zero Emissions Scenario, representing 6.5% of total cumulative emissions reductions. Hydrogen fuel use is particularly critical for reducing emissions in the hard-to-decarbonise sectors in which direct electrification is difficult to implement, i.e. heavy industry (particularly steel manufacturing and chemical production), heavy-duty road transport, shipping and aviation. In the power sector, hydrogen can also provide flexibility by helping to balance rising shares of variable renewable energy generation and facilitating seasonal energy storage.

[3] This excludes industry sector on-site hydrogen production and use, which consumes around 6% of final energy consumption in industry today. Including on-site hydrogen production in industry, hydrogen and hydrogen-based fuels meet 1% of total final energy consumption today, 4% by 2030 and 13% by 2050 in the Net Zero Emissions Scenario.

Policy trends across key areas for hydrogen deployment

Progress in five key areas for hydrogen policymaking

Introduction

Integrating hydrogen as a new vector into energy systems is a complex endeavour: without government intervention, it will not be realised at the pace required to meet climate ambitions. Many governments are therefore already working with diverse stakeholders to address key challenges and identify smart policies that can facilitate this transformation. As needs differ for each country and industry, policies and actions must be based on relevant priorities and constraints, including resource availability and existing infrastructure.

In The Future of Hydrogen, the IEA identified five key areas for governments to define comprehensive policy frameworks to facilitate hydrogen adoption across the entire energy system:

1. Establish targets and/or long-term policy signals.
2. Support demand creation.
3. Mitigate investment risks.
4. Promote R&D, innovation, strategic demonstration projects and knowledge-sharing.
5. Harmonise standards and removing barriers.

The Global Hydrogen Review tracks and reports progress in these areas with the aim of apprising governments and stakeholders of the pace of change in hydrogen policymaking. The Review highlights new policies being adopted around the world, assesses their impacts and identifies potential gaps. Its dual objectives are to help governments adopt or adapt other countries' successful experiences and avoid repeating failures.

1. Establish targets and/or long-term policy signals

In their long-term energy strategies, governments should determine the most efficient way hydrogen can be used to support decarbonisation efforts. They should then set policies that send long-term signals about this role to boost stakeholder confidence in development of a marketplace for hydrogen and related technologies. Integrated actions can guide future expectations, unlock investments and facilitate co-operation among companies and countries.

When The Future of Hydrogen was released in June 2019, only Japan and Korea had published national hydrogen strategies to define the role of hydrogen in their energy systems, and France had announced a hydrogen deployment plan. Since then, 13 countries (Australia, Canada, Chile, the Czech Republic, France, Germany, Hungary, the Netherlands, Norway, Portugal, Russia, Spain and the United Kingdom) have published hydrogen strategies, along with the European Commission. Colombia announced the release of its strategy for the end of September 2021.

Two countries (Italy and Poland) have released their strategies for public consultation and more than 20 others are actively developing them. Several regional governments have also defined hydrogen strategies and roadmaps, including in Australia (Queensland, South Australia, Tasmania, Victoria and West Australia), Canada (British Columbia), China, France, Germany (Baden-Württemberg, Bavaria, North Germany, North Rhine-Westphalia) and Spain (Basque Country).

Some governments have even taken the additional step of defining hydrogen's role in other, overarching policy frameworks. Japan's Green Growth Strategy, for example, describes the country's vision for producing and using hydrogen and for developing international supply chains.

A coherent picture of future-use cases for hydrogen

The strategies published to date show that, with slight differences, almost all countries hold broadly similar views of the role hydrogen should play in their energy systems. Practically all the strategies (15 of 16) highlight its vital importance in decarbonising the transport and industry sectors.

In the case of transport, most governments emphasise medium- and heavy-duty transport, and Japan and Korea envisage an important role for cars. Several governments highlight the potential use of hydrogen and ammonia in shipping, while a smaller number are considering producing synthetic fuels (synfuels) to decarbonise aviation (Germany recently released a power-to-liquids [PtL] roadmap) or using hydrogen in rail transport. Japan has taken the additional step of publishing an Interim Report of the Public-Private Council on Fuel Ammonia Introduction on using ammonia in electricity generation and shipping.

In the industry sector, each country's plans focus on the main industries: some target certain subsectors (chemicals in Chile and Spain; steel in Japan), while others take a more cross-sectoral approach (Canada and Germany). Canada and Chile have highlighted the role of hydrogen in decarbonising mining operations, and all countries with significant refining capacities prioritise this sector as well.

Other potential hydrogen uses that are mentioned in strategies but have received less attention are electricity generation – including energy storage and system balancing (11 of 16) – and heat in buildings (7 of 16). Finally, if international hydrogen trade develops, some countries have a clear plan to become exporters (Australia, Canada, Chile and Portugal) while others have started exploring the possibility of importing hydrogen if national production capacity cannot meet future demand (the European Union, Germany, Japan and the Netherlands).

Different views on how to produce hydrogen

Countries that have adopted hydrogen strategies present quite diverse visions on how it should be produced. Hydrogen production from electricity is common to all strategies, in some cases being the preferred route in the long term. Some prioritise renewable power (Chile, Germany, Portugal and Spain), while others are less specific about the origin of the electricity (France's strategy mentions renewable and low-carbon electricity).

While several governments (9 of 16) have set a significant role for the production of hydrogen from fossil fuels with CCUS, others (including the European Union) consider this option for only the short and medium term to reduce emissions from existing assets while supporting the parallel uptake of renewable hydrogen. Canada has taken a different approach; instead of prioritising any specific production pathway, it is focusing on the carbon intensity of hydrogen production, with targets to drive it to zero over time. Some countries (e.g. Canada and Korea) have flagged the potential use of by-product hydrogen (from the chlor-alkali or petrochemical industries) to meet small shares of demand.

Finally, most strategies refer to the potential for emerging technologies, such as methane pyrolysis or biomass-based routes. As these technologies are still at early stages of development, prospects are considered uncertain.

Intermediate milestones to anchor long-term targets

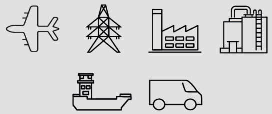
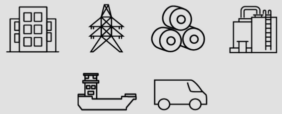
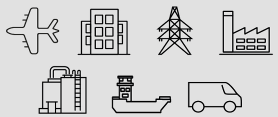
Almost all governments have adopted a phased approach to integrate hydrogen into their energy systems. How they define phases varies, but strategies tend to recognise three stages: scaling up and laying the market foundations (early 2020s); widespread adoption and market maturity (late 2020s to early 2030s); and full implementation of hydrogen as a clean energy vector (post-2030).

Deployment targets, while not present in all strategies, are a common feature to anchor expected progress within these phases. In some cases, targets have been proposed as a vision or an aspiration (Canada, Japan); in others, they convey a firm commitment with the intent to send strong signals to industry about the future marketplace for hydrogen. To date, practically none of these targets is legally binding.

Governments with adopted national hydrogen strategies; announced targets; priorities for hydrogen and use; and committed funding

Buildings Electricity Exports Industry Industry (chemicals) Industry (steel) Mining Refining
Shipping Transport. Aviation

Country	Document, year	Deployment targets (2030)	Production	Uses	Public investment committed
Australia	National Hydrogen Strategy, 2019	None specified	Coal with CCUS Electrolysis (renewable) Natural gas with CCUS	Buildings, Electricity, Exports, Industry, Shipping, Transport.	AUD 1.3 bln (~USD 0.9 bln)
Canada	Hydrogen Strategy for Canada, 2020	Total use: 4 Mt H_2/y 6.2% TFEC	Biomass By-product H_2 Electrolysis Natural gas with CCUS Oil with CCUS	Buildings, Electricity, Exports, Industry, Mining, Refining, Shipping, Transport.	CAD 25 mln by 2026[1] (~USD 19 mln)
Chile	National Green Hydrogen Strategy, 2020	25 GW electrolysis[2]	Electrolysis (renewable)	Buildings, Exports, Industry (chemicals), Mining, Refining, Transport.	USD 50 mln for 2021
Czech Republic	Hydrogen Strategy, 2021	Low-carbon demand: 97 kt H_2/yr	Electrolysis	Industry (chemicals), Transport.	n.a.
European Union	EU Hydrogen Strategy, 2020	40 GW electrolysis	Electrolysis (renewable) Transitional role of natural gas with CCUS	Industry, Refining, Transport.	EUR 3.77 bln by 2030 (~USD 4.3 bln)
France	Hydrogen Deployment Plan, 2018 National Strategy for Decarbonised Hydrogen Development, 2020	6.5 GW electrolysis 20-40% industrial H_2 decarbonised [3] 20 000-50 000 FC LDVs [3] 800-2 000 FC HDVs [3] 400-1 000 HRSs [3]	Electrolysis	Industry, Refining, Transport.	EUR 7.2 bln by 2030 (~USD 8.2 bln)

Country	Document, year	Deployment targets (2030)	Production	Uses	Public investment committed
Germany	National Hydrogen Strategy, 2020	5 GW electrolysis	Electrolysis (renewable)		EUR 9 bln by 2030 (~USD 10.3 bln)
Hungary	National Hydrogen Strategy, 2021	Production: 20 kt/yr of low-carbon H_2 16 kt/yr of carbon-free H_2 240 MW electrolysis Use: 34 kt/yr of low-carbon H_2 4 800 FCEVs 20 HRSs	Electrolysis Fossil fuels with CCUS		n.a.
Japan	Strategic Roadmap for Hydrogen and Fuel Cells, 2019 Green Growth Strategy, 2020, 2021 (revised)	Total use: 3 Mt H_2/yr Supply: 420 kt low-carbon H_2 800 000 FCEVs 1 200 FC buses 10 000 FC forklifts 900 HRSs 3 Mt NH_3 fuel demand(4)	Electrolysis Fossil fuels with CCUS		JPY 699.6 bln by 2030 (~USD 6.5 bln)
Korea	Hydrogen Economy Roadmap, 2019	Total use: 1.94 Mt H_2/yr 2.9 million FC cars (plus 3.3 million exported)(5) 1 200 HRSs(5) 80 000 FC taxis(5) 40 000 FC buses(5) 30 000 FC trucks(5) 8 GW stationary FCs (plus 7 GW exported)(5) 2.1 GW of micro-cogeneration FCs(5)	By-product H_2 Electrolysis Natural gas with CCUS		KRW 2.6 tln in 2020 (~USD 2.2 bln)
Netherlands	National Climate Agreement, 2019 Government Strategy on Hydrogen, 2020	3-4 GW electrolysis 300 000 FC cars 3 000 FC HDVs (6)	Electrolysis (renewables) Natural gas with CCUS		EUR 70 mln/yr (~USD 80 mln/yr)
Norway	Government Hydrogen Strategy, 2020 Hydrogen Roadmap, 2021	n.a.(7)	Electrolysis (renewables) Natural gas with CCUS		NOK 200 mln for 2021 (~USD 21 mln)

Country	Document, year	Deployment targets (2030)	Production	Uses	Public investment committed
Portugal	National Hydrogen Strategy, 2020	2-2.5 GW electrolysis 1.5-2% TFEC 1-5% TFEC in road transport 2-5% TFEC in industry 10-15 vol% H_2 in gas grid 3-5% TFEC in maritime transport 50-100 HRS	Electrolysis (renewables)		EUR 900 mln by 2030 (~USD 1.0 bln)
Russia	Hydrogen roadmap 2020	Exports: 2 Mt H_2	Electrolysis Natural gas with CCUS		n.a.
Spain	National Hydrogen Roadmap, 2020	4 GW electrolysis 25% industrial H_2 decarbonised 5 000-7 500 FC LDVs-HDVs 150-200 FC buses 100-150 HRSs	Electrolysis (renewables)		EUR 1.6 bln (~USD 1.8 bln)
United Kingdom	UK Hydrogen Strategy, 2021	5 GW low-carbon production capacity	Natural gas with CCUS Electrolysis		GBP 1 bln (~USD 1.3 bln)

Note: TFEC = total final energy consumption. (1) In addition to CAD 25 mln, Canada has committed over CAD 10 bln to support clean energy technologies, including H_2. (2) This target refers to projects that at least have funding committed, not to capacity installed by 2030. (3) Target for 2028. (4) From the interim Ammonia Roadmap. (5) Target for 2040. (6) Target for 2025 from the National Climate Agreement, 2019 (currently under revision). (7) Norway's strategy defines targets for the competitiveness of hydrogen technologies and project deployment.

2. Support demand creation

Creating demand for low-carbon hydrogen is critical for its widespread adoption. Policy support to “pull” investment across the value chain will be needed to make projects bankable and overcome deployment hurdles. For technologies that use hydrogen and are ready for commercialisation, policy support to close the price gap with incumbents can stimulate faster deployment and accelerate cost reductions that result from scaling up and learning by doing. Progress is under way, but not enough policies have been implemented to support longer-term targets and create demand for low-carbon hydrogen.

A dynamic situation in the transport sector

National hydrogen strategies place great value on using hydrogen in transport. As fuel cell electric vehicles (FCEVs) are commercially available for passenger cars, light-duty vehicles (LDVs) and buses, several countries have policies to support their deployment.

More than 20 countries offer specific purchase subsidies for FCEVs, ranging from EUR 1 500 (~USD 1 700) per vehicle in Finland to more than USD 30 000 in Korea. In fact, purchasers of fuel cell buses in Korea receive KRW 300 million (~USD 250 000). Tax benefits are in place in at least 20 countries, and at least 17 apply specific company tax benefits to support FCEV adoption in professional fleets.

China launched a new FCEV pilot cities programme in 2020 to enlarge FCEV industry supply chains. In contrast with vehicle purchase subsidies, the scheme rewards clusters of cities based on a series of parameters. To be eligible for financial rewards, city clusters must deploy more than 1 000 FCEVs that meet certain technical standards; achieve a delivered hydrogen price at a maximum of CNY 35.00/kg (~USD 5.00/kg); and provide at least 15 operational hydrogen refuelling stations (HRSs). Based on the plan and how well objectives are met, a maximum of CNY 1.5 billion (~USD 220 million) will be transferred to each selected city cluster between 2020 and 2023.

Hydrogen vehicles may also benefit from programmes to support zero emission vehicles (ZEVs) and implementation of CO_2 emissions standards. Recent examples include California’s ZEV mandate; the Dutch government’s announcement that ZEVs will make up all public transport bus sales by 2025; and the EU CO_2 emissions standards for heavy-duty vehicles (HDVs). In 2018, Switzerland adopted the LSVA road tax, which levies trucks weighing more than 3.5 tonnes but waives the fee for ZEVs. This created an attractive business case for hydrogen trucks, which are expected to reach about 200 by the end of 2021. While not specific to hydrogen vehicles, which have to compete with alternatives such as battery electric vehicles (BEVs), these policies can stimulate FCEV deployment.

Other policies that can support hydrogen uptake in transport are the California Low Carbon Fuel Standard, Canada's Clean Fuel Standard and the UK Renewable Transport Fuel Obligation, which can also spur adoption of low-carbon hydrogen in biofuel production and refining. Meanwhile, in 2020 the Norwegian government announced that the country's largest ferry connection (Bodø-Værøy-Røst-Moskenes) will be fuelled by hydrogen and in March 2021 the Port of Tokyo stated that it will waive the entry fee for ships powered by LNG or hydrogen. These are the first measures implemented to support hydrogen or hydrogen-derived fuels in shipping, but as the technology has not yet reached the commercial level, it will take time to realise the impact of these policies.

Policies to support hydrogen-derived synthetic fuel use in aviation have attracted attention recently. As part of its Fit for 55 package, in July 2021 the European Commission proposed the ReFuel Aviation Initiative to mandate minimum synthetic fuel shares in aviation, rising from 0.7% in 2030 to 28% in 2050. This measure awaits European Council and European Parliament approval. Germany's strategy mentions a minimum quota of 2% synthetic fuels in aviation by 2030, which has now passed the parliamentary process and is legally binding. In addition, Germany's recently released power-to-liquids (PtL) roadmap targets 200 000 tonnes of hydrogen-based sustainable aviation fuel in 2030. The Dutch government has already expressed interest in these types of measures.

Policies for other sectors still under discussion

Little progress has been achieved on policies for low-carbon hydrogen adoption in other sectors. Despite its anticipated importance, few policies have been designed specifically to create demand for low-carbon hydrogen in industry.

Also in its Fit for 55 package, in July 2021 the European Commission proposed a modification of the Renewable Energy Directive to include a 50% renewable hydrogen consumption in industry by 2030. Germany's strategy includes the potential implementation of obligatory quotas for selected clean products (e.g. hydrogen-based steel) and aims to explore how to implement such solutions at the national and European levels.

India has also announced mandatory quotas for using renewable hydrogen in refining (10% of demand from 2023-24, increasing to 25% in the following five years) and fertiliser production (5% of demand from 2023-24, increasing to 20% in the following five years), with potential extension to the steel industry in the near future. This will spur India to replace part of its current capacity for hydrogen produced from natural gas (typically imported) with hydrogen from renewables while also creating new demand for locally produced hydrogen.

Injecting hydrogen into the natural gas grid has also attracted attention as another means of creating new hydrogen demand. While no measures have yet been adopted, some countries are taking steps in this direction. For instance, Portugal's national strategy targets 10-15 vol% H_2 blending by 2030 and Chile is preparing a bill to mandate blending quotas.

Lack of targets and policies for demand creation can stall low-carbon supply expansion

Because most government targets and policies to date have been focused exclusively on enlarging hydrogen supplies, low-carbon hydrogen production has outpaced demand growth. Strategic action is therefore needed to avoid the value chain imbalances that can result in inefficient policy support.

If hydrogen demand is not sufficiently stimulated, producers may not be able to secure off-takers and the development of low-carbon hydrogen supply capacity may held back. This could result in low-carbon hydrogen capacity replacing only certain parts of current production in industrial applications, which would impede scale-up and discourage cost reductions, and ultimately delay adoption of hydrogen as a clean energy vector.

3. Mitigate investment risks

Many projects currently under way face risks related to uncertain demand, lack of experience and value chain complexity. Measures to address risks linked to capital and operational costs can help tip the balance in favour of private investment in these first projects.

European countries are leading the way

European policymakers have been particularly active in implementing measures to mitigate the risks of hydrogen-related project developers. In its Climate Agreement (launched June 2020), the Netherlands proposed including hydrogen in the SDE++ scheme, which offers incentives to develop CO_2 reduction technologies and renewable energy. This scheme recently triggered its intended actions and in May 2021 the Dutch government committed EUR 2 billion for the Porthos project to bridge the gap between current rates for CO_2 emissions allowances and the costs involved in capturing, transporting and storing CO_2 underground. This will facilitate development of projects to produce hydrogen from fossil fuels with CCUS.

In September 2020, the European Commission announced a call for tenders for projects to build electrolysis plants at the 100-MW scale. All proposals have been evaluated and some awarded projects have been announced. Perhaps more importantly, the Commission included hydrogen in the Important Projects of Common European Interest (IPCEI) scheme, which allows projects validated by both member states and the Commission to receive public support beyond the usual boundaries of state aid rules. This is expected to unlock significant project investment across the entire hydrogen value chain, stimulating scale-up in the next decade.

Countries beyond Europe are also taking action. In June 2021, Canada announced a new Clean Fuels Fund to help private investors overcome the barrier of high upfront capital costs to construct new clean fuel production capacity, and will provide support to a minimum of ten hydrogen projects.

Public financial institutions are getting involved

Financial institutions can be critical in mitigating the investment risks of first movers. While the European Investment Bank (EIB) provided significant investments for R&D in hydrogen projects in the last decade, it has now shifted its focus to offer financial support and technical assistance for the development of large-scale projects. The EIB signed related collaboration agreements with France Hydrogène (2020) and the Portuguese government (2021).

In May 2020, the Australian government, through the Clean Energy Finance Corporation, made AUD 300 million available through the Advancing Hydrogen Fund, thereby taking the first steps to facilitate investments in hydrogen projects to scale up production and end uses. In 2021, the government of Chile launched (through CORFO) a USD 50-million call for funding to develop electrolysis projects.

New policy instruments are coming into play

Governments are developing new and innovative policy instruments to support investment in hydrogen projects. In June 2021, the German government announced the H2 Global programme, with the aim of ramping up the international market for hydrogen produced from renewable electricity. The scheme will tender ten-year purchase agreements on hydrogen-based products, providing certainty to investors on project bankability. With a total budget of EUR 900 million, the scheme expects to leverage more than EUR 1.5 billion in private investments.

In its national hydrogen strategy, Germany's federal government also announced that it will launch a new Carbon Contracts for Difference (CCfD) pilot programme to support the use of hydrogen from renewable energy sources in the steel and chemical industries. This programme will pay the difference between the CO_2 abatement costs of the project and the CO_2 price in the EU Emissions Trading Scheme (EU ETS). If the EU ETS price rises above the project's CO_2 abatement costs, companies will have to repay the difference to the government. If the pilot is completed successfully, the scheme may be expanded to other industry subsectors.

The European Commission announced that it is also considering the carbon contracts for difference (CCfD) concept. Recent price increases in the EU ETS – which nearly doubled in 2021 to more than EUR 60/t CO_2 – are expected to limit the public spending needed to bridge the cost gap in these schemes.

Auctions are also a powerful policy instrument, and they have been critical in ramping up other clean energy technologies, such as solar PV and wind energy. They are now about to be applied to hydrogen, with India's New and Renewable Energy Minister announcing (in June 2021) auctions for the production of hydrogen from renewables. The Netherlands' national strategy also mentions the potential use of combined auctions for offshore wind and hydrogen production.

In Chile, the government is holding regular public and open tenders to develop large-scale projects for producing hydrogen from renewable energy sources on public land. As these projects require large land areas, facilitating access to public land with good renewable resources can reduce investment risks and accelerate deployment.

Along with its Hydrogen Strategy, the United Kingdom launched a public consultation on a business model for low-carbon hydrogen with the aim of defining specific policy instruments to help project developers overcome costs barriers.

4. Promote R&D, innovation, strategic demonstration projects and knowledge-sharing

The future success of hydrogen will hinge on innovation. Today, low-carbon hydrogen is more costly than unabated fossil fuel-based hydrogen, which undermines its uptake. Multiple end-use technologies at early stages of development cannot compete in open markets, in part because they have not yet realised the economies of scale that come with maturity. Governments play a key role in setting the research agenda and adopting policy tools that can incentivise the private sector to innovate and bring technologies to the market.

Selected active hydrogen R&D programmes

Country	Programme	Funding and duration
Australia	ARENA's R&D Programme CSIRO Hydrogen Mission	AUD 22 mln (~USD 15 mln) – 5 yr AUD 68 mln (~USD 47 mln) – 5 yr
European Union	Clean Hydrogen for Europe	EUR 1 bln (~USD 1. bln) – 10 yr
France	PEPR Hydrogène	EUR 80 mln (~USD 91 mln) – 8 yr
Germany	National Innovation Programme for Hydrogen and Fuel Cell Technology	EUR >250 mln (~USD 285 mln) – 10 yr
	Wasserstoff-Leitprojekte	EUR 700 mln (~USD 800 mln) – n.a.
Japan	NEDO innovation programmes	JPY 699 bln (~USD 6.5 bln) – 10 yr
Spain	Misiones CDTI	EUR 105 mln (~USD 120 mln) – 3 yr
United Kingdom	Low Carbon Hydrogen Supply	GBP 93 mln (~USD 119 mln) – n.a.
United States	H2@Scale M²FCT – H2New Consortia DOE Hydrogen Program	USD 104 mln – 2 yr USD 100 mln – 5 yr USD 285 m/yr

Hydrogen innovation requires a boost

Programmes to foster hydrogen innovation are not yet flourishing, although some positive signals are emerging and several governments have launched hydrogen-specific programmes to fund R&D in technologies across the entire hydrogen value chain. However, current public R&D spending on hydrogen is below levels dedicated in the early 2000s during the last wave of support for hydrogen technologies (see Chapter Investments and Innovation). Further, integrated efforts will be required to avoid bottlenecks along the value chain.

Government and industry co-operation is critical to ensure the implementation of robust innovation programmes. With more than EUR 1 billion in funding provided since 2008, the Fuel Cells and Hydrogen Joint Undertaking (FCH JU) is a prime example of a public-private partnership to support R&D and technology demonstration. Building on its success, the European Commission will launch the Clean Hydrogen for Europe Joint Undertaking at the end of 2021, with matching budgets of EUR 1 billion from public funding and private investment until 2027.

The European Commission also initiated the European Clean Hydrogen Alliance in July 2021 to bring together industry, national and local public authorities, civil society and other stakeholders to establish an investment agenda for hydrogen. Similarly, the Chilean Energy Sustainability Agency introduced a Green Hydrogen Incubator in 2021 to co-ordinate stakeholders and provide consulting services to facilitate the development of technology demonstration projects. In Morocco, stakeholders from the private sector, academia and the government established the Green Hydrogen Cluster to support the emerging renewable hydrogen sector. In the United States, the Department of Energy (DOE) launched the First Energy Earthshot dedicated to hydrogen, bringing together stakeholders with the target of slashing the cost of clean hydrogen by 80% (to USD 1.00/kg H_2) by 2030.

International co-operation is growing rapidly

Multilateral initiatives and projects can promote knowledge-sharing and the development of best practices to connect a wider group of stakeholders. For instance, Mission Innovation (MI), which works to catalyse R&D action and investment, has engaged with the FCH JU through the Hydrogen Valley Platform to facilitate collaboration and knowledge-sharing within more than 30 hydrogen valleys across the globe. With the launch of the Clean Hydrogen Mission in June 2021, MI took another step to boost R&D in hydrogen technologies, with the goal of reducing end-to-end clean hydrogen costs to USD 2.00/kg by 2030. MI also aims to establish at least 100 hydrogen valleys, to be featured on the Hydrogen Valley Platform.

In addition to the several bilateral agreements signed between governments in recent years, international co-operation agreements have been established between governments and the private sector (the MOUs between the Port of Rotterdam and the governments of Chile and South Australia is one example). All have the short- to medium-term objective of co-operating to share knowledge, best practices and technology development to reduce costs. They also share the long-term aim of laying the foundations for future international hydrogen supply chains to ensure the development of trade in hydrogen and hydrogen-derived fuels.

In June 2020, the energy ministers of the Pentalateral Forum (Austria, Belgium, France, Germany, Luxembourg, the Netherlands and Switzerland) signed a joint political declaration affirming their commitment to strengthen co-operation on hydrogen.

Selected bilateral agreements between governments to co-operate on hydrogen development, 2019-2021

Countries	Objective
Germany - Australia	Formulate new initiatives to accelerate development of a hydrogen industry, including a hydrogen supply chain between the two countries. Focus on technology research and identification of barriers.
Germany - Canada	Form a partnership to integrate renewable energy sources, technological innovation and co-operation, with a focus on hydrogen.
Germany - Chile	Strengthen co-operation in renewable hydrogen and identify viable projects.
Germany - Morocco	Develop clean hydrogen production, research projects and investments across the entire supply chain (two projects have already been announced by the Moroccan agencies MASEN and IRESEN).
Germany - Saudi Arabia	Co-operate on the production, processing and transport of hydrogen from renewable energy sources.
Morocco - Portugal	Examine opportunities and actions needed to develop hydrogen from renewable energy sources.
Netherlands - Chile	Establish a structured dialogue on the development of import-export corridors for green hydrogen, aligning investment agendas and facilitating collaboration among private parties.
Netherlands - Portugal	Co-operate to advance the strategic value chain for producing and transporting renewables-based hydrogen, connecting the hydrogen plans of the two countries.
Japan – United Arab Emirates	Co-operate on technology development, regulatory frameworks and standards to create an international hydrogen supply chain.
Japan - Argentina	Strengthen collaboration on the use of clean fuels and promote investments to deploy large-scale hydrogen production from renewable energy sources.
Japan - Australia	Issue a joint statement highlighting the commitment already in place between the two countries and recognising the importance of co-operation on an international hydrogen supply chain.
Singapore - New Zealand	Boost collaboration on establishing supply chains for low-carbon hydrogen and its derivatives, and strengthen joint R&D, networks and partnerships.
Singapore - Chile	Foster co-operation on projects and initiatives to advance hydrogen deployment through information exchange and the establishment of supply chains and partnerships.
Australia - Korea	Develop joint hydrogen co-operation projects with specific action plans.

5. Harmonise standards and removing barriers

Two broad issues have emerged regarding regulations, codes and standards for hydrogen deployment. The first is the need to review national regulations that define the roles of utilities and grid operators. At present, certain aspects of market structure warrant regulatory frameworks that keep these entities separate. If hydrogen deployment is successful, however, it can concurrently become an integral part of the gas network and support electricity grid resilience and reliability of the electricity grid. Hydrogen will thereby facilitate sector coupling between electricity and gas utilities, creating a new role requiring specific regulation.

The second issue is the need to ensure that a standardisation framework based on national or international norms is in place and is appropriately applicable to the use of hydrogen and its carriers. This ongoing process involves numerous international organisations.

Regulations need to be adapted to remove barriers in the near term

The IPHE's Regulations, Codes, Standards and Safety Working Group conducted a Regulatory Gaps Compendium survey among its participating countries to determine regulatory needs in critical areas for hydrogen and fuel cell deployment. Participants provided input on focal areas within two topics: hydrogen infrastructure and hydrogen for mobility/transportation.

Survey results indicated broad regulatory needs, particularly as industry activity increases and expands beyond road transportation. Critical within the infrastructure area is the establishment of a legal framework for injecting hydrogen into natural gas systems (at both the distribution and transmission levels) and requirements for the scale-up and public use of liquid hydrogen in refuelling infrastructure.

Concerning transportation/mobility, the most critical priority is to enable the use of hydrogen in non-road transport modes – i.e. rail, shipping and aviation. The survey also determined that safety (including maintenance requirements, approvals and inspections) is a priority and improvements should be incorporated into efforts to address the other needs identified.

To remove barriers to hydrogen adoption, some countries have taken the first steps to adapt their regulations. For instance, in 2020 the Chinese National Energy Administration released a draft of the new Energy Law in which hydrogen is classified, for the first time, as an energy carrier. This means hydrogen will now be a freely tradable energy asset and its transportation will be subject to less stringent requirements than for hazardous substances (its previous classification).

Other countries, including Chile, Colombia, Korea and France, have modified their energy legislation to facilitate the adoption of hydrogen as an energy carrier. As tax regulations can also create significant barriers to hydrogen technology endorsement, several countries are exploring options to reduce this impact. The European Commission recently proposed revision of the Energy Taxation Directive to avoid double taxation of energy products, including hydrogen, and Germany announced that hydrogen produced from renewable electricity will not be subject to the levy used to fund support for clean power.

A low-carbon hydrogen market requires carbon accounting standards

International hydrogen trade could become a cornerstone of the clean energy transition, enabling the export of low-carbon hydrogen from regions with abundant access to renewable energy or low-cost production of hydrogen from fossil fuels with CCUS. To facilitate trade, however, relevant standardisation bodies will need to develop international standards – based on a common definition of low-carbon hydrogen – to remove and/or reduce regulatory barriers.

During the 32nd IPHE Steering Committee, countries recognised that developing internationally agreed accounting standards for different sources of hydrogen along the supply chain will be vital to create a market for low-carbon hydrogen. To this end, a Hydrogen Production Analysis Task Force was established to review and reach consensus on a methodology and analytical framework for determining GHG emissions related to one unit of produced hydrogen.

Such a mutually recognised, international framework will avoid mislabelling or double-counting environmental impacts and should provide consensus on an approach to “certificates of origin”. The methodology is based on principles of inclusiveness (methodologies should not exclude any potential primary energy), flexibility (approaches must allow for unique circumstances and hence flexibility), transparency (methodologies must be transparent in approach and assumptions to build confidence), comparability (the approach should be comparable with those used for other energy vectors), and practicality (methodologies must be practical, facilitating uptake by industry and use in the market).

The methodology also describes the requirements and evaluation methods applied from “well to gate” for the most-used hydrogen production pathways: electrolysis, steam methane reforming with CCUS, by-product and coal gasification with CCUS. Over time, the Task Force intends to develop other methods and to potentially apply the approach to different physical states of hydrogen, diverse energy carriers and emissions arising during transport to the end user. In addition to IPHE activities, some countries (e.g. Australia, France and the United Kingdom) have started to develop certification schemes for hydrogen’s carbon footprint.

Research to develop evidence-based safety standards

During its recent bi-annual Workshop on Research Priorities for Hydrogen Safety, the International Association for Hydrogen Safety (HySafe) mapped state-of-the-art and recent progress in pre-normative research to support standards development, including identifying and ranking pending research needs. Ultimately, research needs were identified for five key safety areas: liquid hydrogen use; the compatibility of certain materials (metals and plastics) with hydrogen; hydrogen leak detection; hydrogen phenomena modelling; and electrolysis safety for unsteady-state operations. Despite recent progress, a significant lack of understanding regarding the accidental behaviour of liquid hydrogen was identified as an outstanding challenge. At the engineering level, major research gaps exist for the non-road transport subsectors.

Hydrogen demand

Overview and outlook

Hydrogen demand has grown strongly since 2000, particularly in refining and industry

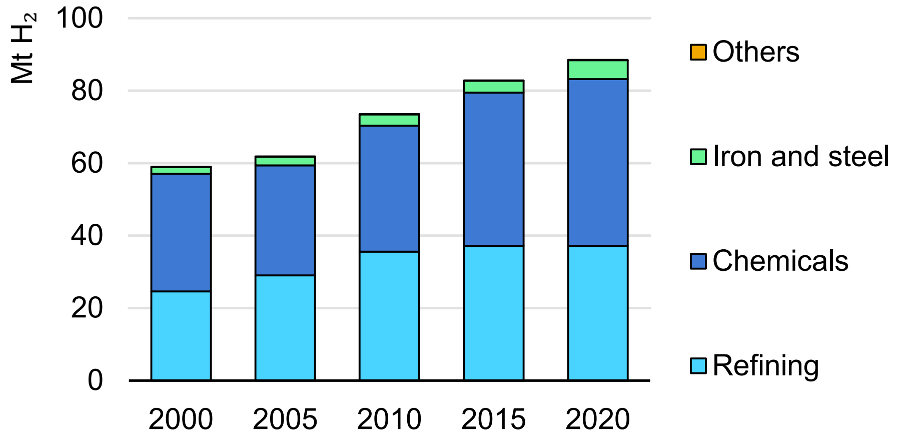
Global hydrogen demand was around 90 Mt H_2[4] in 2020, having grown 50% since the turn of the millennium. Almost all this demand comes from refining and industrial uses. Annually, refineries consume close to 40 Mt H_2 as feedstock and reagents or as a source of energy.

Demand is somewhat higher (more than 50 Mt H_2) in the industry sector, mainly for feedstock. Chemical production accounts for around 45 Mt H_2 of demand, with roughly three-quarters directed to ammonia production and one-quarter to methanol. The remaining 5 Mt H_2 is consumed in the direct reduced iron (DRI) process for steelmaking. This distribution has remained almost unchanged since 2000, apart from a slight increase in demand for DRI production.

The adoption of hydrogen for new applications has been slow, with uptake limited to the last decade, when fuel cell electric vehicle (FCEV) deployment started and pilot projects began to inject hydrogen into gas grids and use it for electricity generation. Positive results from these experiences prompted the development of some hydrogen technologies to the point of commercialisation.

In parallel, concerns about climate change have increased and governments and industry are making strong commitments to reduce emissions. Although this has accelerated the adoption of hydrogen for new applications, demand in this area remains minuscule. In transport, for example, annual hydrogen demand is less than 20 kt H_2 – just 0.02% of total hydrogen demand. As shown in the IEA's Net zero by 2050 roadmap, achieving government decarbonisation goals will require a step change in the pace of rolling out hydrogen technologies across many parts of the energy sector.

Hydrogen demand by sector, 2000-2020

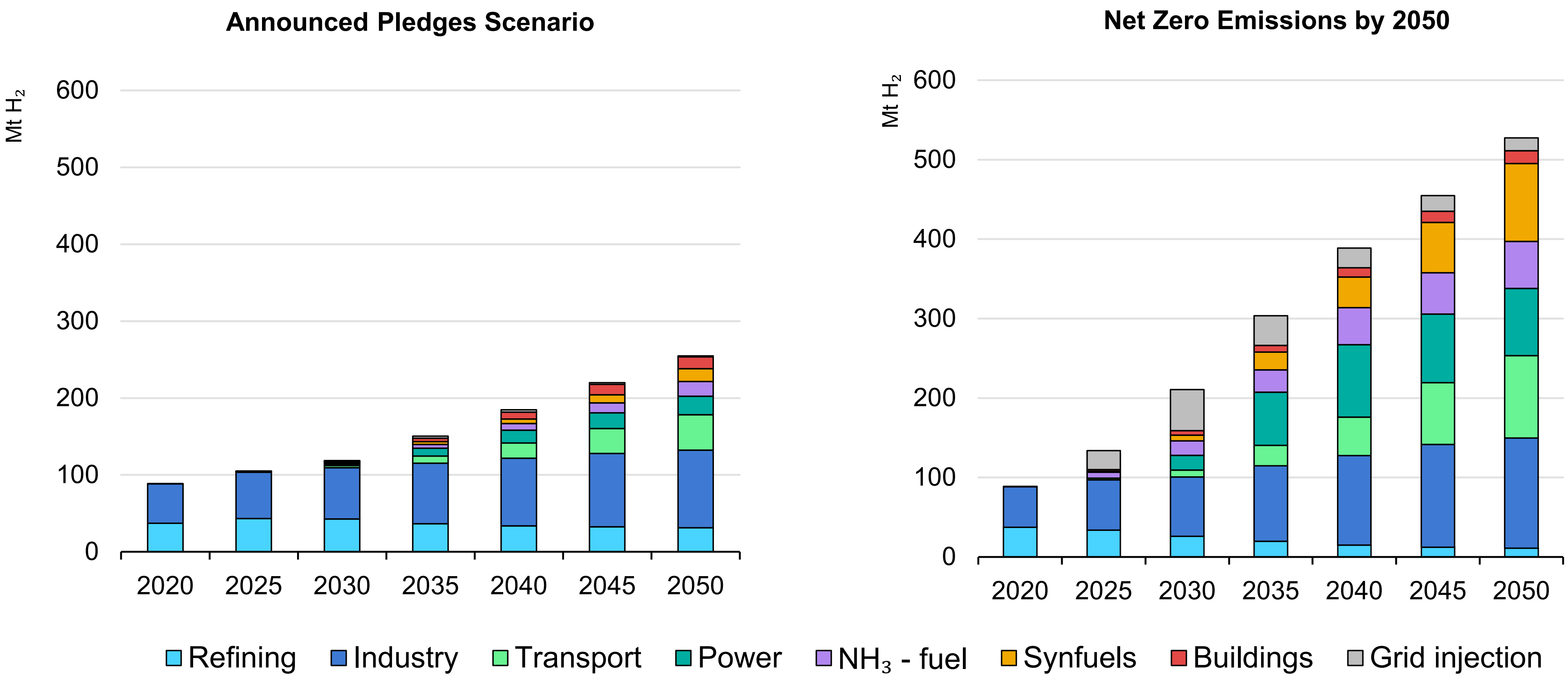


Note: "Others" refers to small volumes of demand in industrial applications, transport, grid injection and electricity generation.

[4] This includes more than 70 Mt H_2 used as pure hydrogen and less than 20 Mt H_2 mixed with carbon-containing gases in methanol production and steel manufacturing. It excludes around 30 Mt H_2 present in residual gases from industrial processes used for heat and electricity generation: as this use is linked to the inherent presence of hydrogen in these residual streams – rather than to any hydrogen requirement – these gases are not considered here as a hydrogen demand.

Government pledges suggest greater hydrogen use, but not nearly enough to the level needed to achieve net zero energy system emissions by 2050

Hydrogen demand by sector in the Announced Pledges and Net zero Emissions scenarios, 2020-2050



Notes: "NH_3 - fuel" refers to the use of hydrogen to produce ammonia for its use as a fuel. The use of hydrogen to produce ammonia as a feedstock in the chemical subsector is included within industry demand.

Hydrogen-based fuel use must expand to meet ambitious climate and energy goals

The pathway to net zero emissions by 2050 requires substantially wider hydrogen use in existing applications (e.g. the chemical industry) and a significant uptake of hydrogen and hydrogen-based fuels for new uses in heavy industry, heavy-duty road transport, shipping and aviation.

In the Net zero Emissions Scenario, hydrogen demand multiplies almost sixfold to reach 530 Mt H_2 by 2050, with half of this demand in industry and transport. In fact, industry demand nearly triples from around 50 Mt H_2 in 2020 to around 140 Mt H_2 in 2050. Transport demand soars from less than 20 kt H_2 to more than 100 Mt H_2 in 2050, owing to the volumes that small shares of hydrogen can achieve in certain segments.

Power sector penetration also increases significantly as hydrogen's use in gas-fired power plants and stationary fuel cells helps to balance increasing generation from variable renewables; integrate larger shares of solar PV and wind; and provide seasonal energy storage. Hydrogen use in buildings also increases, although its penetration is very limited to certain situations in which other clean and more efficient technologies cannot be adopted and/or it is needed to increase electricity grid flexibility.

By 2050, around one-third of hydrogen demand in the Net zero Emissions Scenario is used to produce hydrogen-based fuels such as ammonia, synthetic kerosene and synthetic methane. Ammonia use expands beyond existing applications (primarily nitrogen fertilisers) to be adopted for use as a fuel.

As ammonia has advantages over the direct use of hydrogen for long-distance shipping, in the Net zero Emissions Scenario it meets around 45% of global shipping fuel demand. To reduce CO_2 emissions in power generation, ammonia is also increasingly co-fired in existing coal plants, with some former coal-fired units being fully retrofitted to use 100% ammonia to provide low-carbon dispatchable power.

Synthetic fuels (synfuels) manufactured from hydrogen and CO_2 captured from biomass applications (bioenergy-fired power or biofuel production) or from the atmosphere (direct air capture [DAC]) are also used in energy applications in the Net zero Emissions Scenario. Synthetic kerosene in particular meets around one-third of global aviation fuel demand while synthetic methane meets around 10% of demand for grid gas use in buildings, industry and transport.

Overall, hydrogen and hydrogen-based fuels meet 10% of global final energy demand in 2050[5].

Refining is the only application for which hydrogen demand decreases in the Net zero Emissions Scenario – from close to 40 Mt H_2 in 2020 to 10 Mt H_2 in 2050: the reason is simply that the need to refine oil drops sharply as clean fuels and technologies replace oil-derived products.

Although recent government net zero commitments create momentum for adopting hydrogen-based fuels across the energy system, volumes are insufficient to achieve net zero emissions by 2050. While in the Announced Pledges Scenario hydrogen demand nearly triples to over 250 Mt H_2 by 2050, this is less than half the amount modelled in the Net zero Emissions Scenario.

Demand in the Announced Pledges Scenario is lower in almost all sectors, with refining being the exception as the rate of replacing oil-based fuels is lower. This strongly impacts hydrogen and hydrogen-based fuel uptake in transport applications, with hydrogen use in transport 55% lower in the Announced Pledges than in the Net zero Emissions Scenario. The difference in demand for hydrogen to produce hydrogen-based fuels is the largest, at 80% less for synfuels in the Announced Pledges than in the Net zero Emissions Scenario, and close to 70% less for ammonia production.

Furthermore, a slower rate of renewables deployment means electricity systems require less balancing of generation and seasonal storage in the Announced Pledges than in the Net zero Emissions Scenario; as a result, hydrogen demand for electricity generation in the Announced Pledges Scenario is about one-quarter that of the Net zero Emissions.

In the case of industry, as the largest single use of hydrogen is for feedstock, demand growth is robust in both scenarios, although it is 30% less in the Announced Pledges than in the Net zero Emissions.

[5] This excludes onsite hydrogen production and use in the industry sector. Including on-site hydrogen production in industry, hydrogen and hydrogen-based fuels meet 13% of global final energy demand by 2050 in the NZE.

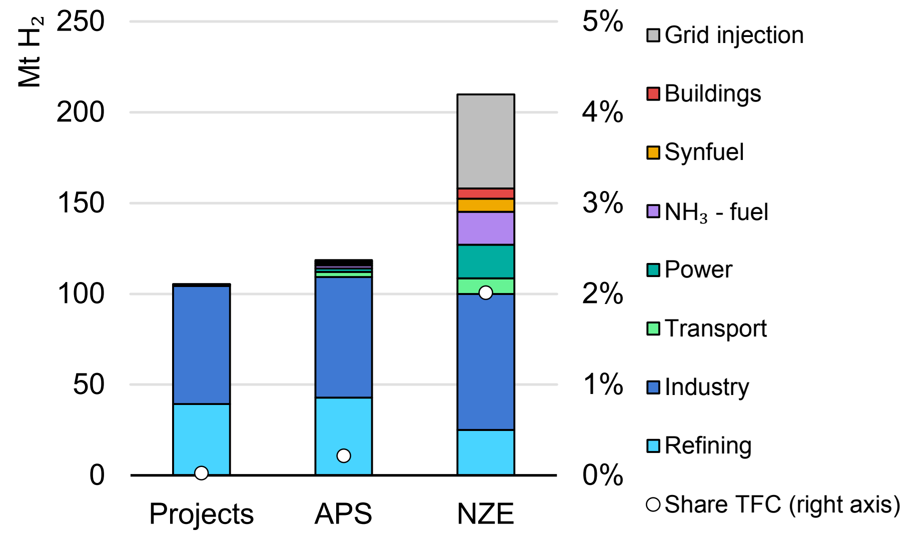
The next decade will be decisive in for laying the foundation for hydrogen's role in the clean energy transition

Increasing the use of hydrogen as a new energy vector is a long-term endeavour, as it can take decades for a new fuel to significantly penetrate the energy mix. Immediate action is therefore required to facilitate the scaling-up process and create the conditions needed by 2030 to ensure that hydrogen technologies can be widely diffused to secure their long-term usefulness in the clean energy transition.

Despite recent strong momentum, projects currently under development indicate that anticipated hydrogen technology deployment in demand sectors does not yet align with the Net zero Emissions Scenario's ambitions. Present government focus on decarbonising hydrogen production is stronger than on stimulating demand for new applications. Apart from notable exceptions for deploying different vehicle types of FCEVs in China, Korea, Japan and some EU countries, few government targets seek to accelerate the adoption of hydrogen-based fuels in end-use sectors.

Moreover, current country ambitions to stimulate hydrogen use for new applications is not sufficient to meet their net zero pledges. Using target-setting on its own as a long-term signal is not effective enough to create the market dynamics needed to unlock private sector investments and stimulate deployment of hydrogen technologies. Targets need to be accompanied by concrete policies to support implementation, including strong demand-side measures that create clearly identifiable markets.

Hydrogen demand in the Projects case, Announced Pledges and Net zero Emissions scenarios, 2030



Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. TFC = total final energy consumption. "Share TFC" excludes on-site hydrogen production and use in the industry sector. Including it, hydrogen and hydrogen-based fuels meet less than 2% of total final energy consumption today, 2% in the APS and 4% in the NZE by 2030. "NH_3 fuel" refers to the use of hydrogen to produce ammonia for its use as a fuel.

Governments need to act quickly and decisively from now until 2030 to trigger this transformation. Implementing quotas or mandates to inject hydrogen into the gas grid can create dependable hydrogen demand in this early deployment phase, which can help building up new low-carbon hydrogen production capacity while governments decide, plan and develop hydrogen-specific infrastructure. Once new infrastructure is ready, low-carbon hydrogen production capacity developed in the early deployment phase can migrate from the natural gas grid to supply hydrogen directly to end users in new applications, several of which should be demonstrated and scaled up in upcoming years.

Adopting hydrogen in transport will require support to deploy FCEVs and fuelling infrastructure. In particular, early demonstration and scaled-up hydrogen use in heavy-duty trucks, for operations in which hydrogen may have advantages over battery electric powertrains (e.g. for certain long-haul operations[6]), and the installation of high-throughput, high-pressure refuelling stations along key road freight corridors are important foundations for hydrogen use in road transport.

While BEVs are expected to dominate the transition to net zero emissions in light-duty road transport owing to their higher efficiency and lower total cost of ownership (TCO), support for near-term adoption of hydrogen fuel cells for light-duty vehicles (LDVs) and buses could boost hydrogen and fuel cell demand as well as infrastructure expansion, ultimately reducing the cost of fuel cell trucks and encouraging their adoption.

Similarly, demonstrating hydrogen and ammonia as fuels for shipping, setting quotas for synfuels in aviation, and deploying the corresponding refuelling infrastructure at ports and airports would support hydrogen and hydrogen-based fuel uptake in these sectors in which emissions are hard to abate.

Demonstration of specific end-use technologies, such as hydrogen-based DRI in steelmaking or high-temperature heating applications, will be critical to unleash significant demand growth in industry. In buildings, all sales of natural gas equipment (when it is preferred over electric heat pumps) should be compatible with hydrogen to allow eventual switching. Demonstration and pilot projects for fuel cells and other hydrogen equipment for domestic applications are needed to raise consumer confidence in hydrogen technologies' operational safety and reduce financial risk.

In the power sector, gas turbine manufacturers are confident they can provide gas turbines that run on pure hydrogen by 2030. To incentivise the use of low-carbon hydrogen to reduce emissions from existing gas-fired plants and provide electricity system

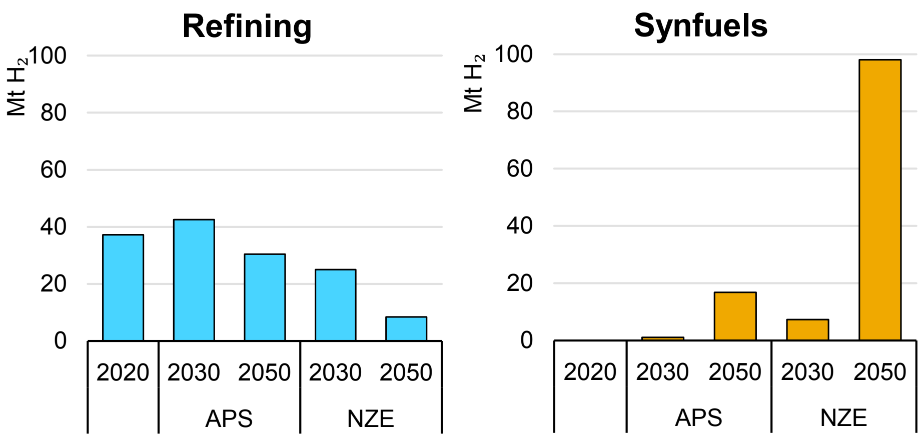
[6] For a comparison of distance-based total cost of ownership (TCO) see Figure 5.7 of Energy Technology Perspectives 2020.

flexibility, strong government support and measures will be needed to close the cost gap between natural gas and low-carbon hydrogen. Co-firing of ammonia in coal-fired power plants has been successfully demonstrated at low co-firing shares, but more RD&D is needed in using pure ammonia directly as fuel in steam or gas turbines.

Refining

Hydrogen demand in refining declines as climate ambitions increase, but synfuels offer new opportunities

Hydrogen demand in refining and synthetic fuels production in the Announced Pledges and Net zero Emissions scenarios, 2020-2050



Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario.

Oil refining was the single largest consumer of hydrogen in 2020 (close to 40 Mt H_2). Refineries use hydrogen to remove impurities (especially sulphur) and to upgrade heavy oil fractions into lighter products. China is the largest consumer of hydrogen for refining (close to 9 Mt H_2/yr), followed by the United States (more than 7 Mt H_2/yr) and the Middle East (close to 4 Mt H_2/yr). Together, these three regions account for more than half of global demand.

Around-half of refining demand is met with by-product hydrogen from other processes in the refinery (e.g. catalytic naphtha reforming) or from other petrochemical processes integrated into certain refineries (e.g. steam crackers). The remainder is met by dedicated on-site production or merchant hydrogen sourced externally. The majority of on-site production is based on natural gas reforming, with some exceptions such as the use of coal gasification, which makes up almost 20% of dedicated hydrogen production at refineries in China.

In 2020, hydrogen production to meet refining demand was responsible for close to 200 Mt CO_2 emissions. However, some ongoing efforts to reduce these emissions are already operative: six plants with facilities retrofitted with CO_2 capture and two others using electrolysers to produce hydrogen. At least another 30 projects are under development to retrofit current fossil-based hydrogen production with CCUS; develop new capacities based on advanced reforming technologies coupled with CCUS; or deploy electrolysis capacities. In the short term, refineries can offer anchor demand for the development of low-carbon hydrogen supplies.

Oil refining is the only sector that shows declining hydrogen demand in the Announced Pledges and Net zero Emissions scenarios. As climate ambitions increase, oil refining activity declines more sharply as oil demand declines, especially after 2030. In the Announced Pledges Scenario, hydrogen demand increases to more than 40 Mt H_2 to then drop to around 30 Mt H_2 in 2050. The Net zero Emissions shows 25 Mt H_2 in 2030 and 10 Mt H_2 in 2050. Dropping oil demand will create a dilemma for refinery operators, as investing in decarbonising current hydrogen production can be difficult to justify if falling demand entails the risk of stranded assets.

However, the emergence of new sources of hydrogen demand could bolster the business case for such investments by offering the opportunity to supply developing hydrogen markets and meet demand in new sectors (e.g. transport, other industry applications and electricity generation), such as those covered in the Announced Pledges and the Net zero Emissions scenarios. Using low-carbon hydrogen could be an option to decarbonise high-temperature-heat operations in refineries, helping meet the net zero targets of oil and gas companies. Producing low-carbon synthetic hydrocarbon fuels (synfuels) is another significant opportunity. Synfuels are "drop-in" fuels, meaning they can directly replace fuels that are currently oil-derived and make use of existing distribution infrastructure and end-use technologies without modifications.

Demand for such fuels grows in both the Announced Pledges and Net zero Emissions scenarios as they replace incumbent fossil fuels in applications for which direct electrification is challenging. Refineries can also use established supply chains to deliver synfuels to end users, serving today's users of oil-derived fuels. Converting hydrogen into synfuels is very costly, however, which could be a primary impediment to their widespread use (see Chapter Hydrogen supply). The expertise and skills of refinery operators will be critical to develop innovative, efficient and cost-effective solutions.

By 2030 in the Announced Pledges Scenario, hydrogen demand for synfuels reaches 1 Mt H_2. By 2050, it climbs to over 15 Mt H_2, more than making up for the more than 5 Mt H_2 drop in refining demand. In the Net zero Emissions Scenario, hydrogen demand for synfuels climbs to more than 7 Mt H_2 by 2030, compensating for nearly two-thirds of the more than 10-Mt H_2 drop in refining demand. By 2050, it reaches close to 100 Mt H_2, not only replacing the 26 Mt H_2 drop in refining demand but more than doubling current demand – and representing a significant investment opportunity.

If all projects currently in the pipeline materialise (including those already operational; under construction; having reached final investment decision; and undergoing feasibility studies), around 0.25 Mt H_2[7] could be used in synfuel production by 2030, meeting one-fifth of Announced Pledges Scenario requirements but just 3% of the Net zero Emissions Scenario's.

[7] This could increase to 0.5 Mt H_2 if projects at very early stages of development are included (a co-operation agreement among stakeholders has just been announced).

Selected projects operative and under development to decarbonise hydrogen production in refining

Project	Location	Status	Start-up date	Technology	Size
Horizon Oil Sands	Canada	Operational	2009	Oil + CCUS	438 kt CO_2/yr
Port Arthur *	US	Operational	2013	Natural gas + CCUS	900 kt CO_2/yr – 118 kt H_2/yr
Port Jerome *	France	Operational	2015	Natural gas + CCUS	100 kt CO_2/yr – 39 kt H_2/yr
Quest	Canada	Operational	2015	Natural gas + CCUS	1 000 kt CO_2/yr – 300 kt H_2/yr
H&R Ölwerke Hamburg-Neuhof	Germany	Operational	2018	Electrolysis (PEM)	5 MW
North West Sturgeon refinery	Canada	Operational	2020	Bitumen gasification + CCUS	1 200 kt CO_2/yr
Pernis refinery (gasification)	Netherlands	CCU project – Operational CCUS project – Feasibility studies	2005 2024	Heavy residue gasification with CCU (CCUS from 2024)	400 kt CO_2/yr – 1 000 kt H_2/yr 1 000 kt CO_2/yr – 1 000 kt H_2/yr
Refhyne (2 phases)	Germany	Phase 1 – Operational Phase 2 – Feasibility studies	2021 2025	Electrolysis (PEM)	10 MW 100 MW
HySynergy (3 phases)	Denmark	Phase 1 – Under construction Phases 2/3 – Feasibility studies	2022 2025-30	Electrolysis (PEM)	20 MW 300 MW / 1 000 MW
Multiphly	Netherlands	Under construction	2022	Electrolysis (SOEC)	2.6 MW
Prince George refinery	Canada	FID	2023	Electrolysis (Unknown)	n.a.
OMV Schwechat Refinery	Austria	FID	2023	Electrolysis (PEM)	10 MW
Westkuste 100 (2 phases)	Germany	Phase 1 – FID Phase 2 – Feasibility studies	2023-28	Electrolysis (Alkaline)	30 MW / 300 MW
H24All	Spain	Feasibility studies	2025	Electrolysis (Alkaline)	100 MW
Gela biorefinery	Italy	Feasibility studies	2023	Electrolysis (PEM)	20 MW
Taranto Sustainable refinery	Italy	Feasibility studies	2023	Electrolysis (PEM)	10 MW
Castellon refinery	Spain	Feasibility studies	2023	Electrolysis (Unknown)	20 MW
Pernis refinery (electrolysis)	Netherlands	Feasibility studies	2023	Electrolysis (Unknown)	200 MW
Saras Sardinia refinery	Italy	Feasibility studies	2024	Electrolysis (Unknown)	20 MW
Stanlow refinery	United Kingdom	Feasibility studies	2025	Natural gas + CCUS	90 kt H_2/yr
H2.50	Netherlands	Feasibility studies	2025	Electrolysis (Unknown)	250 MW
Preem CCS	Sweden	Feasibility studies	2025	Natural gas + CCUS	500 kt CO_2/yr
Grupa Lotos refinery	Poland	Feasibility studies	2025	Electrolysis (Unknown)	100 MW
Zeeland refinery	Netherlands	Feasibility studies	2026	Electrolysis (Unknown)	150 MW
Lingen refinery (2 phases)	Germany	Phase 1 – Feasibility studies Phase 2 – Early stages	2024 n.a.	Electrolysis (Unknown)	50 MW 500 MW
Deltaurus 1 (2 phases)	Netherlands	Phase 1 – Feasibility studies Phase 2 – Early stages	2024 n.a.	Electrolysis (Unknown)	150 MW 1 000 MW

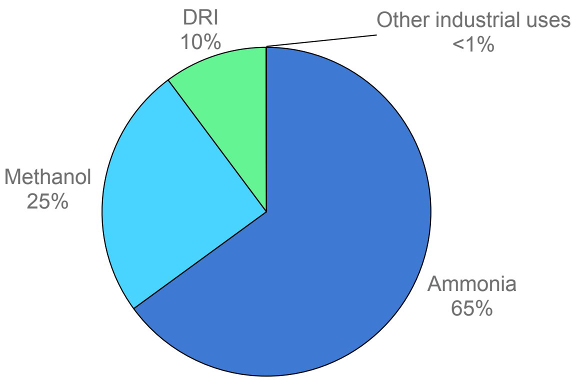
* These plants produce merchant hydrogen to supply refineries.
Notes: Size expressed in captured CO_2 for projects using CCUS and in electrolysis installed capacity for projects using electrolysis.

Industry

Hydrogen technologies are key to industry decarbonisation

Accounting for 38% of total final energy demand, industry is the largest end-use sector and accounts for 26% of global energy system CO_2 emissions. Across industry, 6% of total energy demand is used to produce hydrogen, which serves primarily as a feedstock for chemical production and a reducing agent in iron and steel manufacturing. Industry demand for hydrogen is 51 Mt annually.

Hydrogen demand in industry, 2020



Note: DRI = direct reduced iron.

Economic development and population growth will require greater output from the key industry sectors that currently use hydrogen, however it is produced. The pursuit of net zero goals for energy systems will drive changes in supply for current uses and initiate new uses, impacting existing assets. Industrial hydrogen demand in the Announced Pledges Scenario therefore rises to 65 Mt by 2030, a 30% increase over current figures, with new uses accounting for 5%. By 2050, demand doubles from today, with the share of new uses rising to 26%.

In the context of clean energy transitions, a major shift to low-carbon hydrogen – produced via electrolysis or through the continued use of fossil fuel technologies equipped with CCUS – displaces current reliance on fossil fuels in hydrogen production. In 2020, industry produced 0.3 Mt of low-carbon hydrogen, mostly through a handful of large-scale CCUS projects, small electrolysis projects in the chemical subsector, and one CCUS project in the iron and steel subsector. By 2030 in the Announced Pledges Scenario, low-carbon hydrogen consumption in industry reaches 7 Mt H_2, growing by a factor of almost 25 to make up 10% of total industry hydrogen demand.

However, analysis of the current pipeline of low-carbon hydrogen projects suggests that around 55% of global demand projected in the Announced Pledges Scenario in 2030 will be met.[8] CCUS-equipped

[8] This could increase to almost 70% if projects at very early stages of development are included (a co-operation agreement among stakeholders has just been announced).

projects producing low-carbon hydrogen are close to projected deployment: with the current CCUS pipeline expected to produce 1.0 Mt of low-carbon hydrogen, they fall just 7% short of the Announced Pledges Scenario's demand of 1.1 Mt H_2. In sharp contrast, electrolytic hydrogen – a key source of low-carbon hydrogen needed to reach climate goals in industry – lags far behind. Announced electrolytic projects expected to be operational by 2030 account for only one-third of required demand in the Announced Pledges Scenario (close to 6 Mt H_2).

Reaching net zero emissions by 2050 requires even higher hydrogen deployment. Relative to the Announced Pledges Scenario, Net zero Emissions shows total hydrogen demand from industry 11% higher in 2030 and 32% higher in 2050 – almost three times greater than current demand. Low-carbon hydrogen plays an even larger role, amounting to 21 Mt H_2 by 2030 (more than three times higher than in the Announced Pledges Scenario). As early as 2030, electrolytic hydrogen consumption is almost triple that of the Announced Pledges Scenario while CCUS-equipped production is more than five times higher.

Chemicals

With demand of 46 Mt H_2 in 2020, ammonia and methanol production – together with other smaller-scale chemical processes – account for the vast majority of industrial use of hydrogen.

Ammonia, predominantly used to produce nitrogen fertilisers, accounts for 2% of global final energy demand and around 1% of energy-related and process CO_2 emissions from the energy sector. Aside from fertiliser[9] applications (70% of total demand), ammonia is used for industrial applications in explosives, synthetic fibres and other specialty materials. As producing 1 tonne of ammonia requires 180 kg of hydrogen, total production of 185 Mt in 2020 required 33 Mt H_2 as feedstock, i.e. 65% of total industry hydrogen demand.

Methanol production is the second-largest consumer of hydrogen in industry, requiring 130 kg H_2/t produced commercially from fossil fuels. Its largest-volume derivative is formaldehyde, but several fuel applications, either directly or after conversion, are also important (e.g. methyl-tert-butyl ether). The 100 Mt of methanol produced globally accounts for 28% of hydrogen demand in the chemical subsector and one-quarter of total industry hydrogen demand. In China, methanol serves as an intermediate in the production of olefins (key chemical precursors for making plastics) from coal, an

[9] Specific decarbonisation opportunities for this subsector are explored in the IEA's forthcoming Nitrogen Fertiliser Technology Roadmap.

alternative to conventional oil-based routes. Producing methanol generates, on average, 2.2 t CO_2 per tonne of end product.

Demand for hydrogen in the chemical subsector is expected to grow, particularly because of rising demand for ammonia and methanol. In the Announced Pledges Scenario, it increases nearly 25% by 2030 and close to 50% by 2050. As current methods to produce both chemicals require hydrogen (irrespective of how it is generated), by 2050 total hydrogen demand from chemicals is roughly the same in the Net zero Emissions Scenario.

New demand comes mostly from new applications in which hydrogen displaces fossil fuels for generating the high-temperature heat required for producing chemicals. Thus, converting to low-carbon hydrogen, rather than expanding the use of hydrogen, is the main challenge for the chemical subsector. Opportunities to obtain low-cost, low-carbon hydrogen may spark chemical production in new regions that have access to low-cost renewable electricity but not fossil fuels.

CO_2 capture is already a mature process technology in specific chemical industry applications. During ammonia production, core process equipment separates CO_2 from hydrogen, and the CO_2 is then used for industrial-scale urea production (note: this leaves a significant portion of generated emissions unabated).

In the United States, the practice of using CO_2 captured from ammonia production for enhanced oil recovery (EOR) is well established; similar projects are also operational in Canada and China. Based on the size of the capture installation and assumptions on capture rate and the energy intensity of the process, in aggregate these projects produce around 0.2 Mt of low-carbon hydrogen annually for ammonia production.

Using electrolytic hydrogen for ammonia production, particularly with variable renewable electricity, is at an early stage of development. Nevertheless, several demonstration projects (1-4 kt H_2/yr) are advancing quickly, including a project by Fertiberia and Iberdrola (Spain) to blend hydrogen produced by solar PV-powered electrolysis, expected to become operational at the end of 2021; a CF Industries electrolyser project (United States); the Western Jutland Green ammonia project (Denmark); and green fertiliser projects with Yara (in the Netherlands, Norway and Australia). In addition, some recently announced projects – extensions of the Fertiberia and Iberdrola partnership, Australian projects in Dyno Nobel's Moranbah plant, and the Origin Energy development in Tasmania's Bell Bay – are aiming to scale up this concept to 30-140 kt H_2/yr.

For methanol production, most projects currently sourcing low-carbon hydrogen are related to electrolytic hydrogen. Volumes are very small to date, with pilot plants operating at 1 MW in Germany and 0.25 MW in Denmark, for example. Together with pre-commercial plants in Iceland and China, electrolytic hydrogen amounts to about 2 kt/yr of low-carbon hydrogen. Several projects aiming to demonstrate the use of electrolytic hydrogen for methanol production at scales in the range of 1-10 kt H_2/yr include e-Thor and Djewels (the Netherlands), North-C-Methanol (Belgium), and LiquidWind (Sweden).

Although only small projects capturing CO_2 emissions from methanol production are operating, projects currently under development are about to grow in size. Two demonstration projects capturing CO_2 for EOR are under way in China, another is to start in the United States in 2025, and one is under consideration for Canada by 2025. Together, they can add more than 0.3 Mt/yr of low-carbon hydrogen.

New applications in chemicals include the use of hydrogen for producing high-value chemicals (via either methanol or synfuel used in steam crackers) or for providing high-temperature process heat in downstream chemical production. By 2030, such uses trigger additional low-carbon hydrogen demand of 1.0 Mt in the Announced Pledges Scenario and 2.1 Mt in the Net zero Emissions.

While hydrogen demand per tonne of ammonia and methanol is expected to remain stable, rising demand for chemical products, along with the possibility of sourcing hydrogen from renewable electricity and of using additional hydrogen for heat to produce other chemicals in addition to ammonia and methanol, could revolutionise the sector.

Producing chemical products without carbon fuels could also create opportunities to find new sources of carbon, including CCUS and DAC. Overall, the chemical subsector's project pipeline represents only 2.3 Mt of low-carbon hydrogen through 2030,[10] short of targets of 4 Mt in the Announced Pledges Scenario and 7 Mt in Net zero Emissions. Clearly, a redoubling of efforts is required over the next ten years.

Iron and steel

The iron and steel subsector accounts for 10% of industry hydrogen demand, stemming specifically from use in the DRI-EAF steelmaking process route, which accounts for 7% of total crude steel production globally. In the DRI process, hydrogen is produced as a component of a synthesis gas, which together with carbon monoxide reduces iron ore to sponge iron. The synthetic gas is a mixture of carbon monoxide and hydrogen, depending on the energy source used in DRI production. On average, around 40 kg H_2 is needed per tonne of sponge iron. The traditional DRI mixture can contain 0-70% hydrogen.

The most common steel production route today (the integrated route, a sequence of blast and basic oxygen furnaces) does not require hydrogen as an input, as it uses carbon monoxide-rich gases for

[10] 3.1 Mt H_2 if projects at very early stages of development are included

iron ore reduction. However, a small amount of hydrogen is still generated within the blast furnace as an intermediate and as a by-product in the process off-gases.

As a result of announced policies and projects as well as increased steel production through the DRI-EAF process, hydrogen demand from iron and steel almost doubles by 2030 in the Announced Pledges Scenario and increases more than fivefold by 2050. In sharp contrast to small differences in scenario projections in the chemical subsector, Net zero Emissions shows hydrogen demand from iron and steel 85% higher than in the Announced Pledges Scenario by 2030 and 70% higher by 2050. New uses for hydrogen form a key decarbonisation strategy for the iron and steel subsector; in turn, high decarbonisation ambition will spur required levels of deployment.

Multiple new applications present novel opportunities for the future of hydrogen in iron and steel production, with potential volumes of demand in a hydrogen-based DRI-EAF route being the most important. While commercial-scale production for 100% hydrogen-based DRI is not expected until the early 2030s, this route opens an avenue for extensive hydrogen use in the sector. Blending pure hydrogen in DRI and blast furnaces to substitute for a portion of coal and gas, as is currently being trialled, is an incremental step towards the near zero emissions production of crude steel.

Hydrogen can also be used to generate heat for ancillary units, including rolling and other finishing processes, despite being less attractive than induction technology. By 2030, these new uses amount to 2 Mt H_2 or 17% of hydrogen use in iron and steel in the Announced Pledges Scenario and 9 Mt H_2 in Net zero Emissions. Most of these uses of hydrogen are still at pilot or demonstration scale; to meet deployment levels outlined in the Announced Pledges and Net zero Emissions scenarios, rapid action is needed in the next five years for their full commercialisation.

Projects in the pipeline amount to 0.5 Mt[11] of low-carbon hydrogen use. These include the longest-standing low-carbon hydrogen project – a DRI plant equipped with CCUS in United Arab Emirates, which captures CO_2 for use in nearby EOR. In Germany, the Carbon2Chem project uses CO_2 captured from blast furnace gas for methanol production; using some of the carbon entering the blast furnace twice lowers emissions overall relative to a counterfactual in which methanol is produced from fossil fuels (by far, the most widespread practice today). Opportunities to convert gases arising from iron and steelmaking into other chemicals are also under development.

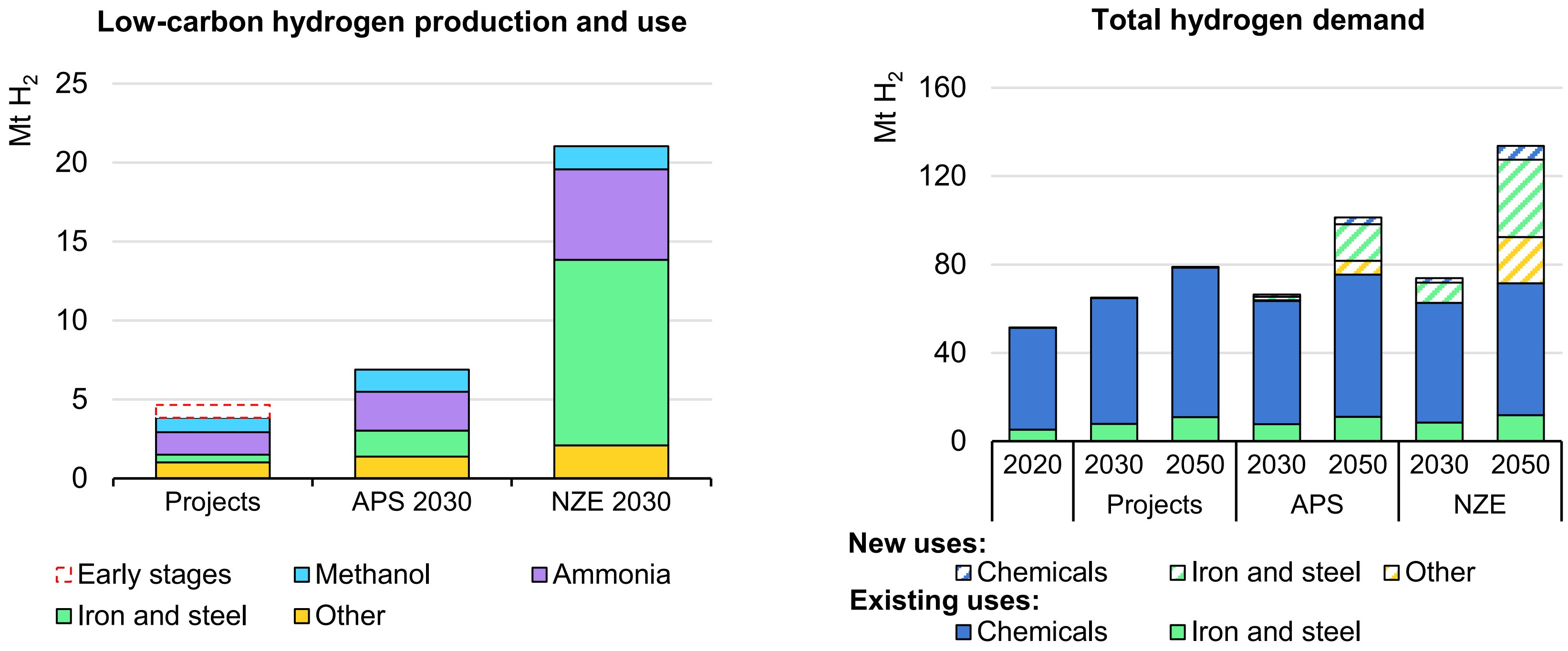
Multiple EU projects are also trialling hydrogen injection into DRI and blast furnaces. The SALCOS (Germany) and H2FUTURE (Austria) projects are operating trials that substitute electrolytic hydrogen to reduce natural gas consumption, amounting together to over

[11] 0.8 Mt H_2 if projects at very early stages of development are included.

1 kt H_2/yr. Thyssenkrupp has successfully trialled the substitution of coal by hydrogen in one tuyere of one of its blast furnaces in Germany and is currently testing higher blending rates. ArcelorMittal (Spain) has also committed to build a DRI unit using hydrogen produced directly from renewable sources.

Aside from blending hydrogen in existing DRI and blast furnaces, high blending shares (up to 100%) in hydrogen-based DRI facilities offer an opportunity to produce steel with very limited use of fossil fuels. As early as the 1990s, a 0.5 Mt full hydrogen-based plant was already operational in Trinidad and Tobago (it is no longer active). The HYBRIT project, developed by SSAB, LKAB and Vattenfall – which will produce sponge iron using 100% hydrogen in combination with biomass – is working towards transitioning from a pilot to large-scale (~1 Mt of DRI) operation by 2025 in Sweden. In June 2021, Volvo Cars signed a collaboration agreement with SSAB to be an off-taker of the fossil-free steel produced in this project.

Low-carbon hydrogen use, 2030, and total hydrogen demand in industry in the Projects case, Announced Pledges and Net zero Emissions scenarios, 2020-2050



Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. Other applications include hydrogen use for ceramics production, nickel refining and industrial heating.
Source: IEA (2021), Hydrogen Projects Database.

Selected projects that can increase the use of low-carbon hydrogen in industry

Project	Location	Status	Start-up date	Technology	Size
Ammonia					
Coffeyville fertiliser	United States	Operational	2013	CO_2 capture from oil-based ammonia production; used for EOR	1 Mt CO_2/yr
PCS Nitrogen	United States		2013	CO_2 capture from gas-based ammonia production; used for EOR	0.7 Mt CO_2/yr
Nutrien fertiliser	Canada		2020	CO_2 capture from gas-based ammonia production; used for EOR	0.3 Mt CO_2/yr
Olive Creek	United States	Under construction	2021	Ammonia production via methane pyrolysis	n.a.
Fertiberia/Iberdrola	Spain	Phase 1 – Under construction Phases 2-4 – Feasibility studies	Phase 1 – 2021 Phases 2-4 – 2027	Hydrogen production from solar PV for ammonia production	Phase 1 – 20 MW Phases 2-4 – 810 MW
Western Jutland Green ammonia	Denmark	FID	2023	Electrolytic ammonia production from renewables	10 MW
CF industries	United States		2023	Electrolytic ammonia production using electricity from the grid	20 MW
Green fertiliser project Porsgrunn	Norway		2023	Electrolytic ammonia production using electricity from the grid	Up to 25 MW
Engie - Yara Pilbara	Australia		2023	Electrolytic ammonia production from renewables	10 MW
HyEx	Chile	Feasibility studies	2024	Electrolytic ammonia production form solar PV	50 MW
Yara Sluiskil	Netherlands		2025	Electrolytic ammonia production from renewables	100 MW
Barents blue ammonia	Norway		2025	CO_2 capture and stored from gas-based ammonia production	1 Mt NH3/yr
Esbjerg green ammonia	Denmark		2027	Electrolytic ammonia production from offshore wind	1 GW
CF Fertilisers Ince	United Kingdom		n.a.	CO_2 capture and stored from gas-based ammonia production	0.3 Mt CO_2/yr
Methanol					
Commercial Plant Svartsengi	Iceland	Operational	2011	Electrolytic methanol production from dedicated renewables	6 MW
Karamay Dunhua Oil Technology CCUS EOR	China		2015	CO_2 capture and stored from methanol production; used for EOR	0.1 Mt CO_2/yr
MEFCO2	Germany		2019	Electrolytic methanol production	1 MW
Power2Met	Denmark		2020	Electrolytic methanol production	0.25 MW
Fine Chemical Industry Park of Lanzhou	China		2020	Electrolytic methanol production from dedicated renewables	4.5 MW
Green lab skive	Denmark	Under construction	2022	Electrolytic methanol production from dedicated renewables	12 MW
DJEWELS Chemiepark	Netherlands	Feasibility studies	2022	Electrolytic methanol production from dedicated renewables	20 MW
Lake Charles Methanol	United States		2025	Production of hydrogen and methanol from petcoke gasification with CCUS	4.2 Mt CO_2/yr

Project	Location	Status	Start-up date	Technology	Size
North-C-Methanol	Belgium	Phase 1 – Feasibility studies Phase 2 – Early stages	2024 2028	Electrolytic methanol production from dedicated renewables	Phase 1 – 63 MW Phase 2 – 300 MW
Power-to-Methanol	Belgium		2023 n.a.	Electrolytic methanol production from dedicated renewables	10 MW 100MW
			Iron and steel		
Al Reyadah CCUS	United Arab Emirates	Operational	2016	CCUS plant applied on DRI; captured CO_2 used for EOR	0.8 Mt CO_2/yr
Carbon2Chem	Germany		2018	Use of blast furnace gases for methanol production	2 MW
H2FUTURE	Austria		2019	Feeding hydrogen via the coke gas pipeline into resource-optimised blast furnaces	6 MW
GrInHy2.0	Germany		2020	Use of waste heat from integrated steelworks for H_2 production	0.72 MW
SALCOS	Germany		2021	Blending of hydrogen into natural gas-based DRI	2.5 MW
HYBRIT	Sweden	Phase 1 – Operational Phase 2 – Under construction	Phase 1 – 2021 Phase 2 – 2025	100% hydrogen-based steelmaking currently operating at pilot scale; plan to move to demonstration plant by 2025	Phase 1 – 4.5 MW Phase 2 – n.a.
Thyssenkrupp steel plant	Germany	Early stages	2022 2025	Hydrogen injection into blast furnaces	100 MW 400 MW
ArcelorMittal	Spain		2025	Use of hydrogen produced from solar PV electrolysis in DRI	n.a.
H2 Green Steel	Sweden		2030	100% hydrogen-based steelmaking using dedicated renewables	1.5 GW
HBIS	China		n.a.	Using high levels of hydrogen together with coke oven gas in DRI	n.a.
			Other applications		
Sun Metals Zinc Refinery	Australia	FID	2022	Replacement of natural gas in zinc refinery process	1 MW
BHP Nickel West Green Hydrogen	Australia	Early stages	2023	Use of electrolytic hydrogen for nickel refining	10 MW
ORANGE.BAT Castellon	Spain		2024	Use of green hydrogen for ceramic production	100 MW
Grange Resources Renewable Hydrogen	Australia		n.a.	Use of hydrogen to replace natural gas for industrial heating in pelletising facilities	100 MW
GREENH2KER	Spain		n.a.	Use of green hydrogen for ceramic production	n.a.

Source: IEA (2021), Hydrogen Projects Database.

Regional insights for hydrogen in industry

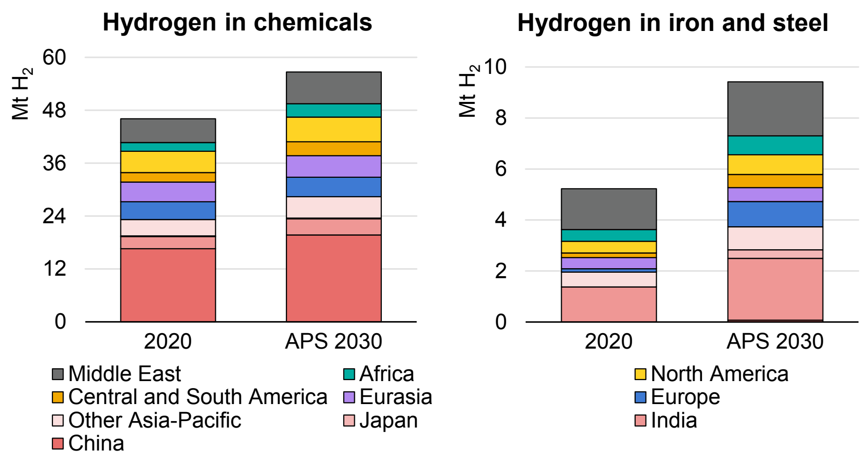
The Asia-Pacific region currently accounts for half of global industrial hydrogen demand, with China alone taking a major portion (17 Mt H_2) for ammonia and methanol production. India is the region's second-highest consumer (4 Mt H_2) for coal-based DRI and ammonia and methanol production. This region remains the front runner in 2030 in the Announced Pledges Scenario, with total demand reaching 32 Mt H_2, used to produce 65 Mt of steel (through fossil and hydrogen-based DRI), 95 Mt of ammonia and 80 Mt of methanol. With growth across all sectors, China accounts for almost two-thirds of Announced Pledges Scenario hydrogen demand. Demand in India rises by 50%, driven mainly by the iron and steel subsector. In the absence of a stated net zero target, growth in India (in the Announced Pledges Scenario) comes largely from coal-based DRI production.

The Middle East is the second-highest hydrogen-consuming region (7 Mt H_2 in 2020), mainly for ammonia and methanol production. By 2030, demand in the Announced Pledges Scenario rises to 9 Mt, prompted by increased chemical production.

Hydrogen consumption remains largely stable in North America, Europe and Eurasia, each rising from 4-5 Mt H_2 currently to around 6 Mt H_2 by 2030 in the Announced Pledges Scenario, mainly due to increased demand from the iron and steel subsector. This is based on the assumption of developed countries maintaining current production levels, even though their share in global output declines as that of maturing developing regions – which require materials to build their infrastructure – increases.

Central and South America show the largest relative growth to 2030: from a low starting point of 2.3 Mt H_2, expanding ammonia and methanol production and rising steel output via DRI-EAF routes boost hydrogen demand by 60%.

Hydrogen demand in industry by sector and region in the Announced Pledges Scenario, 2020-2030



Note: APS = Announced Pledges Scenario.

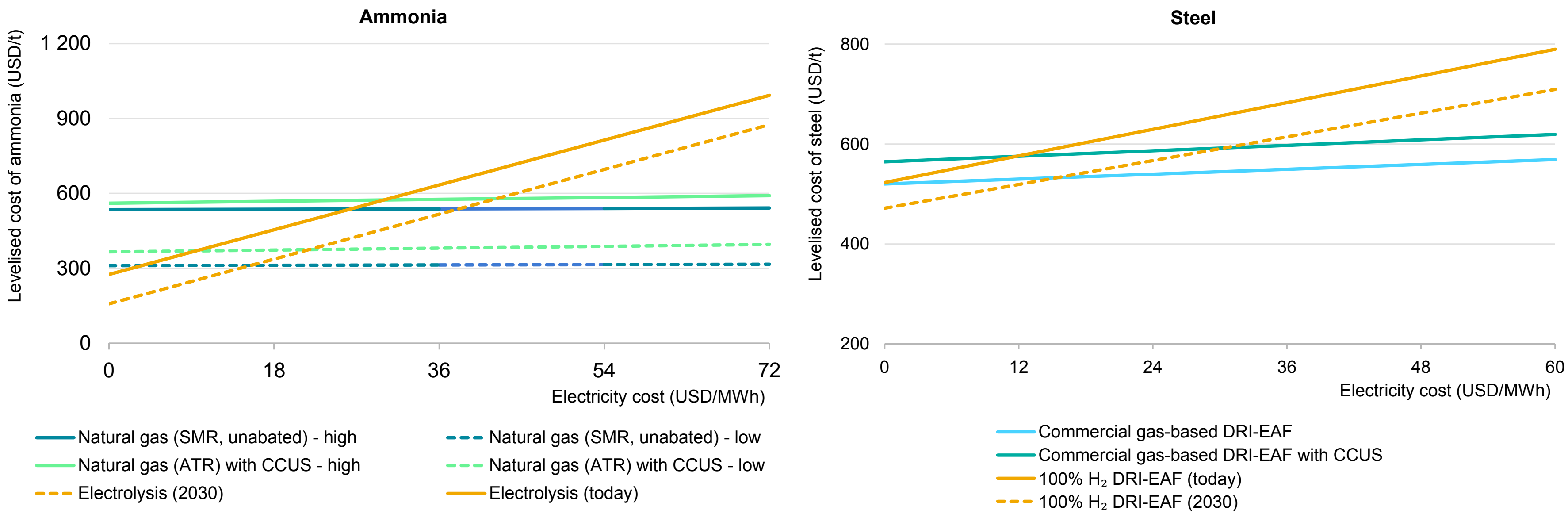
Cost considerations

Today, fossil fuels are the lowest-cost source of industry feedstocks, reduction agents and high-temperature heat for industry in virtually all regions. With carbon prices rising in several markets and the cost of generating electricity from renewables falling rapidly, methods for using low-carbon hydrogen to produce iron and steel as well as chemicals are approaching the competitiveness threshold, with commercial routes currently deployed.

The cost-competitiveness of a low-carbon hydrogen application in industry is determined primarily by capital expenditures and energy costs (particularly for natural gas and electricity). For both ammonia and DRI-EAF steelmaking, low-carbon hydrogen can be produced using either natural gas or electricity. In ammonia production, at 2030 costs for capital equipment (electrolysers and other core process equipment) and natural gas prices of USD 2-10/MBtu with no carbon price, the electrolysis pathway competes with the natural gas with CCUS route at electricity costs of USD 20-40/MWh. For the hydrogen-based DRI-EAF route, the electricity cost range at which it is competitive with natural gas with CCUS is similar, i.e. around USD 30/MWh, when considering natural gas prices of USD 6/MBtu.

These electricity price ranges correspond to high capacity factors (95%) and are very low compared with those for typical industrial consumers in many parts of the world or expected electricity prices in the fully decarbonised grids of the future. Ongoing development in the direct use of variable renewable electricity in electricity-intensive processes (including the use of hydrogen buffer storage and enhanced process flexibility) and declining core equipment (particularly electrolyser) costs are likely to make these methods more competitive as the realised cost of electricity and subsequent hydrogen costs approach these ranges.

Cost sensitivities for ammonia and steel production



Notes: SMR = steam methane reforming. ATR = autothermal reforming. DRI-EAF = direct reduced iron - electric arc furnace. CCUS = carbon capture, utilisation and storage. Techno-economic assumptions available in the Annex.

Transport

Greater hydrogen use is necessary to decarbonise transport

The transport sector is responsible for over 20% of global GHG emissions and one-quarter of final energy demand, with oil products supplying 90% of the energy it consumes. To date, hydrogen use in the sector has been limited, representing less than 0.01% of energy consumed. Nevertheless, hydrogen and hydrogen-based fuels can offer emissions reduction opportunities, especially in hard-to-electrify transport segments (e.g. long-haul, heavy-duty trucking, shipping and aviation).

In the Announced Pledges Scenario, hydrogen and hydrogen-based fuel consumption in transport climbs to 520 PJ or 0.4% of transport energy demand in 2030. Almost 60% of this demand is for road vehicles, as fuel cell vehicle stock expands to over 6 million. Shipping represents almost one-fifth of the demand, with hydrogen and ammonia constituting 1% of shipping fuel consumption in 2030. Similarly, hydrogen and synthetic fuels account for almost 1% of rail energy consumption. In aviation, hydrogen-based synthetic fuel use remains low, making up less than 1% of consumption. By 2050, demand for hydrogen and hydrogen-based fuels across all transport end-uses is over 15 times higher than in 2030, meeting 6% of the sector's energy demand.

In the Net zero Emissions Scenario, hydrogen and hydrogen-based fuel deployment is accelerated and demand reaches 2.7 EJ in 2030, representing 2.6% of transport energy demand. As in the Announced Pledges Scenario, the greatest share of demand (over 45%) is for road vehicles. In shipping, hydrogen accounts for almost 2% and ammonia almost 8% of fuel consumption in 2030. Synthetic fuels make up 1.6% of aviation fuel consumption in 2030 in the Net zero Emissions Scenario. By 2050, hydrogen and hydrogen-based fuels meet over one-quarter of total transport energy demand in this scenario.

Status of hydrogen and fuel cells for transport

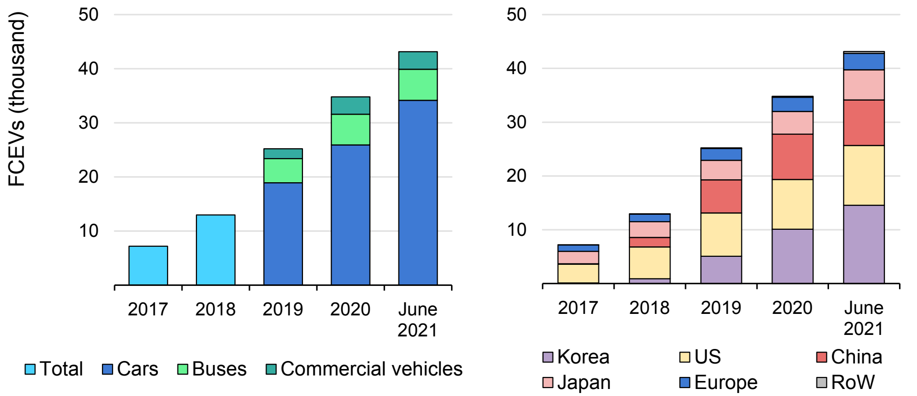
Road transport

More than 40 000 FCEVs were on the road globally by the end of June 2021.[12] Stocks grew an average 70% annually from 2017 to 2020, but in 2020 stock growth fell to only 40% and new fuel cell car registrations decreased 15% (<10 000 new vehicles), mirroring contraction of the car market overall due to the Covid-19 pandemic. However, more than 8 000 FCEVs were sold in the first half of 2021, with record-high monthly sales recorded in California (759 in March) and Korea (1 265 in April).

Global FCEV deployment has been concentrated largely on passenger light-duty vehicles (PLDVs), constituting 74% of registered FCEVs in 2020. Three commercial fuel cell PLDV models are on the market[13] (Hyundai NEXO, Honda Clarity[14] and second-generation Toyota Mirai), with other original equipment manufacturers (OEMs) announcing plans to launch models over the next few years.

Buses, despite being deployed earlier and offering a greater number of fuel cell models (12 according to Calstart's Zero-Emission Technology Inventory tool), currently represent only 16% of total FCEV stock. Almost 95% are in China, which has also led deployment of fuel cell trucks, with >3 100 in operation in 2020.

Fuel cell electric vehicle stock by segment and region, 2017-June 2021



Notes: FCEV = fuel cell electric vehicle. RoW = rest of world.
Sources: AFC TCP provided data on stocks from 2017-2020; 2021 new registrations are based on IPHE Country Surveys, Korea Ministry of Trade, Industry and Energy, and the California Fuel Cell Partnership.

Only 5 fuel cell truck models are currently available, but 11 are expected by 2023. Daimler Truck AG and Volvo Group announced a joint venture, cellcentric, to develop, produce and commercialise fuel

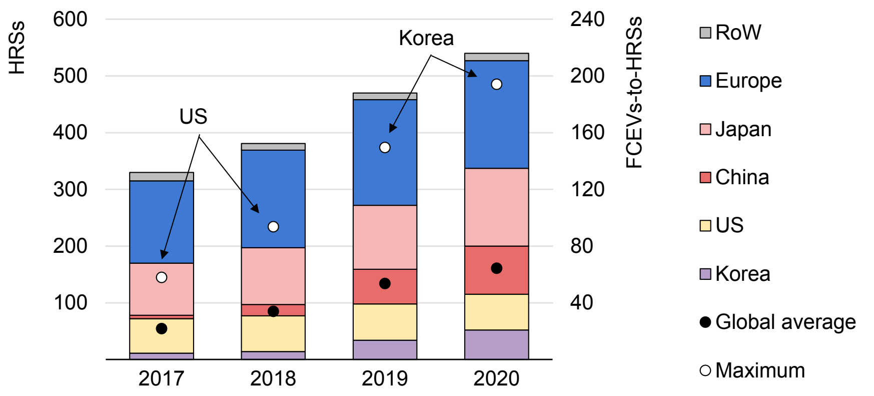
[12] For comparison, EV stock totalled 11 million at the end of 2020.
[13] 350 EV models were available in 2020.

[14] Honda announced discontinuation of the Clarity series (both plug-in hybrid and fuel cell models) as of August 2021, though the Clarity fuel cell will remain available for lease through 2022.

cell systems for long-haul trucking, among other applications. Along with IVECO, OMV and Shell, both companies also signed the H2Accelerate agreement to collaborate on large-scale hydrogen truck deployment in Europe.

Some OEMs, such as Cummins and MAN, are building and testing prototype hydrogen-fuelled internal combustion engines for commercial vehicle applications, which are at a lower technology readiness level than hydrogen fuel cells.

Hydrogen refuelling stations by region and ratio of hydrogen refuelling stations to fuel cell electric vehicles, 2017-2020



Notes: HRS = hydrogen refuelling station. FCEV = fuel cell electric vehicle. RoW = rest of world.
Source: AFC TCP Deployment Status of Fuel Cells in Road Transport: 2021 Update.

At an average year-on-year increase of almost 20% during 2017-2020, the number of hydrogen refuelling stations (HRSs) is growing more slowly than that of FCEVs. The ratio of FCEVs to HRSs[15] is thus increasing, particularly in countries with the highest FCEV sales. In 2020, this ratio reached almost 200:1 in Korea and 150:1 in the United States, compared with just 30:1 in Japan.[16] This reflects, in part, excess HRS capacity, as stations are built anticipating FCEV growth.

Recent stations tend to have higher capacities than initial stations. In 2020, California unveiled a 1 200 kg/day station and allocated funding to construct stations of up to 1 620 kg/day; this is 2.5-3.5 times the average station size funded since 2012. In July 2021, the largest hydrogen station to date opened in Beijing, with a capacity of 4 800 kg/day.

Station refuelling pressure varies according to the vehicle market served. In most countries, the majority of stations dispense hydrogen at 700 bar to serve fuel cell cars. In China, most stations dispense at 350 bar to serve bus and truck fleets. Work is ongoing on station and component design and on fuelling protocols to enable high-throughput dispensing for trucks with 700-bar onboard storage, which will support a range of ~800 km – almost double that of current fuel cell trucks (~400 km). Some stakeholders, including Daimler, Hyzon

[15] In the absence of complete data on station capacity and dispensing, this ratio aims to provide some indication of station utilisation.

[16] For reference, the gas/diesel vehicle to station ratio in the United States is about 1 800:1.

and Chart Industries, are exploring onboard liquid hydrogen storage and refuelling to enable truck ranges of >1 000 km.

Rail

Hydrogen and fuel cell technologies have been demonstrated in rail applications, including mining locomotives, switchers and trams, since the early 2000s. In 2018, the first commercial service of a hydrogen fuel cell passenger train (developed by Alstom) began a 100-km route in Germany. Two Alstom trains in Germany have since driven >180 000 km, and more countries have started testing and adopting fuel cell trains.

In 2020, a hydrogen train entered regular passenger service in Austria, and trials began in the United Kingdom and the Netherlands. In Europe, France, Italy and the United Kingdom have all placed orders for hydrogen fuel cell trains, while the largest fleet – 27 hydrogen trains – is slated to begin permanent, regular operations in Germany in 2022.

Countries such as China, Korea, Japan, Canada and the United States are also showing interest in hydrogen fuel cell trains. In addition to passenger trains, hydrogen trams, line-haul and switching locomotives are in various stages of development and deployment. Where direct electrification of lines is difficult or too costly, deploying fuel cell rail applications can help decarbonise the sector.

Shipping

Hydrogen fuel cells have been demonstrated on several coastal and short-distance vessels since the early 2000s. None are yet commercially available, but the commercial operation of fuel cell ferries is expected to begin in 2021 in the United States and Norway. Most hydrogen-fuelled vessels currently under demonstration or planned for deployment in the next few years are passenger ships, ferries, roll-on/roll-off ships and tug boats, typically with fuel cell power ratings of 600 kW to 3 MW. Furthermore, a recent EU partnership aims to build a hydrogen ferry with 23 MW of fuel cell power.

Past and ongoing projects span both gaseous and liquid onboard hydrogen storage. Due to the low volumetric density of hydrogen (whether in gaseous or liquid form), direct use of hydrogen will be limited to short- and medium-range vessels, especially those with high power requirements that cannot be met through battery electrification.

Hydrogen-based fuels are also attracting attention for use as maritime fuels for large oceangoing vessels. Green ammonia in particular can be used in internal combustion engines to eliminate vessel CO_2 emissions. Major industry stakeholders have announced plans to make 100% ammonia-fuelled maritime engines available as early as 2023 and to offer ammonia retrofit packages for existing vessels from 2025.

The CEM Global Ports Hydrogen Coalition

Launched at the 12th Clean Energy Ministerial (1 June 2021), the CEM Global Ports Hydrogen Coalition aims to strengthen collaboration between government policymakers and port representatives to scale up low-carbon hydrogen use.

The IEA's The Future of Hydrogen identifies ports and coastal industrial hubs (where much of the refining and chemical production that currently uses hydrogen is concentrated) as opportune places to support the near-term scale-up of low-carbon hydrogen production and use. The shift from fossil-based to low-carbon hydrogen by industries in these clusters would boost hydrogen fuel demand by ships and trucks serving the ports as well as by nearby industrial facilities (e.g. steel plants), which would drive down costs.

To enlarge dialogue on hydrogen potential for port operations, the Coalition convenes numerous ports and stakeholders, including the International Association of Ports and Harbours and the World Ports Climate Action Program as well as regional associations (e.g. the European Sea Ports Organisation). The Hydrogen Council, the world's leading industry initiative, will also participate in Coalition activities along with other industry stakeholders.

Methanol has also been demonstrated as a fuel for the maritime sector and is relatively more mature than hydrogen and ammonia. Given its compatibility with existing maritime engines, methanol could be a near-term solution to reduce shipping emissions, but ultimately ammonia offers deeper decarbonisation potential.[17]

Aviation

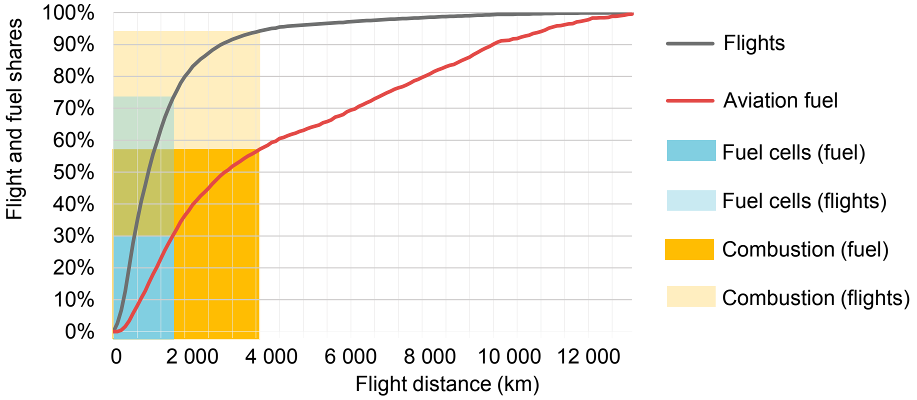
Interest in using hydrogen for aviation has also been growing. The industry group ATAG sees a role for hydrogen fuel cells for flights of up to 1 600 km, and hydrogen combustion for short flights and potentially for medium-haul ones. Assuming the technology is developed successfully, hydrogen fuel cells could be used in 75% of commercial flights but account for only ~30% of aviation fuel.

Technically, hydrogen combustion could be used for longer flights, potentially covering almost 95% of flights and 55% of fuel consumption, but equipment would be needed to mitigate NOx emissions.[18] Sustainable drop-in aviation fuels, including hydrogen-based fuels and biofuels, will be needed to decarbonise at least longer-haul flights, although means to mitigate non-CO_2 climate-warming effects may be required.

[17] However, ammonia combustion results in N_2O and NOx emissions that may require additional equipment to mitigate climate and air pollution impacts.

[18] A recent McKinsey & Company study prepared for the Clean Sky 2 JU and FCH JU is more optimistic about hydrogen use in aviation and provides a comparison of its climate impacts with those of synthetic fuels.

Hydrogen potential, by share of flights and fuel use in commercial passenger aviation



Note: Shading indicates shares of aviation fuel use (solid) and flights (transparent) that could theoretically be offset by hydrogen aircraft, given successful technology development to meet industry targets.
Source: IEA analysis based on OAG flight database.

Whether used with fuel cells or directly combusted, using hydrogen will require new aircraft system designs. Airbus is exploring various hydrogen aircraft concepts, focused on a capacity of up to 200 passengers and a 3 700-km range, with the goal of having a commercial aircraft available by 2035. Smaller companies working on hydrogen aircraft solutions include ZeroAvia, which targets the first commercial offering of a hydrogen plane with a 900-km range in 2024, and Universal Hydrogen, which aims to develop hydrogen storage solutions and conversion kits for commercial aircraft.

Boeing recently partnered with Australia's Commonwealth Scientific and Industrial Research Organisation (CSIRO) to publish a roadmap for hydrogen in the aviation industry that considers opportunities for hydrogen use in aircrafts and airport applications (buses, stationary power, ground support equipment, taxis, trains and freight trucks). Remaining technical challenges include light-weighting cryogenic storage tanks (with minimal boil-off) and developing hydrogen infrastructure for delivery (likely pipelines with near- or on-site liquefaction) and high-flowrate liquid refuelling.

Deployment of hydrogen in other mobile applications

Material handling equipment

Deploying zero-emissions material handling equipment, which includes forklifts and other machinery, is particularly important for indoor operations. Quick refuelling (~2 minutes) is cited as a benefit of fuel cells: in contrast with battery electric equipment, which forces drivers to return to a central location during a shift to swap out batteries, hydrogen refuelling can be situated more strategically throughout a warehouse. Fuel cells also perform particularly well in refrigerated environments, whereas cold temperatures degrade batteries.

Forklifts have proven to be an early commercial application for fuel cells. The United States currently has >40 000 hydrogen forklifts, with Plug Power being the major provider. Japan targets 10 000 by 2030, an ambitious scale-up from its current 330, and Belgium, Canada, France and Germany also each have fuel cell material handling equipment numbering in the hundreds. In Chile, Walmart has announced plans to convert 150 battery forklifts to fuel cell, powered by green hydrogen.

Mining and agricultural equipment

Hydrogen fuel cells may also be used to help decarbonise heavy off-road applications such as mining and agricultural equipment. As part of its national decarbonisation policy and Green Mining Plan, Chile supports projects to investigate and develop hydrogen-fuelled mining trucks, and the mining industry in general is investing in hydrogen technologies for mining equipment.

Anglo American expects to begin testing the first fuel cell mining truck in the second half of 2021 at a platinum group metal mine in South Africa. Komatsu, the Japanese construction equipment maker, plans to develop a fuel cell mining dump truck, aiming to commercialise it by 2030. While electric mining trucks powered by catenary lines already exist, fuel cell trucks offer decarbonisation potential for routes that power lines do not reach.

Agricultural equipment company New Holland, which showcased a fuel cell tractor in 2011, has now developed (as a transitional technology) a dual-fuel tractor that runs on a hydrogen-diesel blend. Other companies such as H2X and H2Trac are also developing fuel cell tractors.

Insights into regional strategies for hydrogen fuels in transport

China

China currently has the third-largest FCEV stock. Unlike other countries, it has focused on deploying fuel cell buses and trucks, and it now has the highest number in the world. Owing to a previous subsidy scheme, which set the fuel cell requirement at just 30 kW to qualify, fuel cells have been used mainly as range extenders. A new rewards-based policy framework aims to accelerate hydrogen demonstration at the regional (or city-cluster) level and focuses on the FCEV operation and supply chain, including hydrogen production and vehicle hydrogen consumption.

China has not yet approved type-IV hydrogen tanks used for 700-bar onboard storage, which partially explains its past emphasis on deploying mainly buses and trucks. While trucks and buses are expected to dominate FCEV sales in the next few years, regulatory approval and deployment of fuel cell cars will likely be needed to reach targets outlined in China's Technology Roadmap 2.0. The Society of Automotive Engineers is aiming for 50 000-100 000 FCEVs in 2025 and 1 million between 2030 and 2035.

In non-road applications, China has developed a hydrogen tram and hybrid locomotive. An ammonia fuel-ready tanker now being built could become the first maritime vessel to operate on this fuel.

Europe

At the end of 2020, over 2 600 FCEVs were operating in Europe, with more than 1 000 in Germany. More than 90% of Europe's FCEVs are light-duty, and about 130 are fuel cell buses. Germany also leads in the number of HRSs, with 90 operating at the end of 2020 (of 190 across Europe).[19]

The Fuel Cell and Hydrogen Joint Undertaking (FCH JU) has supported a wide variety of FCEV demonstration and deployment projects, including taxis, delivery vans, buses and refuse trucks. As a result, the deployment of fuel cell taxis in Europe has been relatively high, most notably in Paris (100), the Hague (~40), Copenhagen (~10) and London (>50). Madrid has announced plans to deploy 1 000. Several European countries (the Czech Republic, France, the Netherlands, Portugal and Spain) have set FCEV targets, together aiming for ~415 000 FCEVs by 2030.

[19] The European Commission's Fit for 55 package's revisions to the Alternative Fuels Infrastructure Directive aims to ensure the HRS network is dense enough to "allow for seamless travel" of FCEVs, with an emphasis on heavy-duty vehicles.

Europe has been a leader in commercialising fuel cell trains. Additionally, the European Union has funded demonstrations of fuel cell-powered maritime vessels, including EUR 5 million (~USD 5.9 million) for the FLAGSHIPS project, which is deploying a hydrogen cargo transport vessel in France and a hydrogen passenger/car ferry in Norway, and EUR 10 million (~USD 11.8 million) for the ShipFC project, which will install a 2-MW ammonia fuel cell on an offshore vessel.

In July 2021 the European Commission presented the ReFuelEU Aviation proposal, which would require a minimum share of sustainable aviation fuel at all EU airports, including a continually increasing minimum share of synthetic aviation fuel. It aims to increase the share of synthetic aviation fuel from 0.7% in 2030 to 28% in 2050.

Additionally, the German government recently released a power-to-liquids (PtL) roadmap targeting the consumption of 200 000 tonnes of hydrogen-based sustainable aviation fuel in 2030. Meanwhile, as part of its *Plan de relance aéronautique* (a programme to help the aerospace industry recover from Covid-19 impacts), the French government has granted EUR 800 000 for development of a small (two-seat) hybrid hydrogen aircraft. The FCH JU has also funded the HEAVEN project, aimed at developing and integrating a high-power fuel cell and cryogenic hydrogen storage system into an existing small aircraft.

Japan

At the end of 2020, Japan had 4 100 fuel cell cars and 100 fuel cell buses, and by mid-2021 the total had surpassed 5 500. With 137 HRSs at the end of 2020, Japan currently has the most in the world. Future (2030) targets include 800 000 PLDVs, 1 200 buses, 10 000 forklifts and ~1 000 HRSs (recently revised upwards from 900 as part of Japan's Green Growth Strategy).

To support targeted level of FCEV adoption, Japan aims to make them price-competitive with comparable hybrid EVs, particularly by reducing the cost of fuel cells and hydrogen storage systems. Japan is also targeting HRS cost reductions;[20] to date, prescriptive regulations have contributed to stations costing twice that in other parts of the world. Current HRS development and operations are financially supported through Japan Hydrogen Mobility (JHyM), a consortium of 26 private companies, financial institutions and the government.

[20] HRS cost reduction targets include reducing capital expenses from JPY 350 million (~USD 3.2 million) in 2016 to JPY 200 million (~USD 1.8 million) around 2025.

The East Japan Railway Company, partnering with Hitachi and Toyota, has announced plans to develop a hydrogen train, with testing to begin in 2022. To meet International Maritime Organisation (IMO) standards on GHG emissions for international shipping, Japan is also investigating hydrogen- and ammonia-fuelled vessels. In 2020, the government published the Roadmap to Zero Emissions in International Shipping, which targets introduction of a first-generation zero emissions ship by 2028.

Korea

Korea took the lead in FCEVs in 2020, with >10 000 cars and >50 buses on the road. Its FCEV stock doubled from 2019 to2020, and by the end of June 2021 an additional 4 400 fuel cell cars had been registered. Purchase subsidies from central and local governments cover about half of the purchase price of the popular, domestically produced Hyundai NEXO. In the Hydrogen Economy Roadmap, FCEV targets are set at 2.9 million cars, 80 000 taxis, 40 000 buses and 30 000 trucks by 2040. In the 2020 New Deal, the government set an interim target of 200 000 FCEVs in 2025.

Korea had 52 operational HRSs at the end of 2020, and the government is targeting 310 by 2022 and 1 200 by 2040. The Hydrogen Energy Network (HyNet) was therefore established in 2019 with an investment of USD 119 million to build ~100 HRSs by 2022.

According to Korea's hydrogen roadmap, the government plans to expand its focus to include hydrogen ships, trains and drones once the road vehicle market has matured. In fact, the government recently provided funding (USD 13 million) to the Korean Railroad Research Institute to develop the world's first liquefied hydrogen-based locomotive, slated for testing at the end of 2022.

United States

The United States currently has the second-largest FCEV fleet, with >9 200 at the end of 2020. Most are in California, where the state government has supported HRS construction with funding of USD 166 million. At the end of 2020, there were 45 retail stations open in California and a total of 63 public and private HRSs across the country.

The California Energy Commission estimates the state will have 179 HRSs by 2027 with capacity to support 200 000 FCEVs, though this would miss the target of 200 HRS by 2025. Despite industry plans to expand the FCEV market to the north-eastern US states, regulatory barriers in some states are impeding deployment.

To date, the US government has not established federal targets for FCEV deployment. However, the California Fuel Cell Partnership, an industry and government collaboration, has announced its ambition to have 1 million FCEVs and 1 000 HRSs in the state by 2030.

To guide R&D efforts, the US Department of Energy has set cost and performance targets for fuel cells for light- and heavy-duty vehicles. In 2019, the DOE published heavy-duty long-haul truck targets, including reducing the cost of the fuel cell system to USD 60/kW and increasing its durability (i.e. lifetime) to 30 000 hours. To support R&D to meet these targets, the DOE established and funded the Million Mile Fuel Cell Truck Consortium.

California government agencies have also supported vehicle deployments, including the first fuel cell ferry (launch expected in 2021), development of a hydrogen fuel cell switching locomotive and the deployment of heavy-duty hydrogen trucks.

Outlook for hydrogen in transport

Road transport

Road vehicles account for the highest share of hydrogen and hydrogen-based fuel consumption in transport in 2030 under both the Announced Pledges (58%) and Net zero Emissions scenarios (45%). FCEV stock, across all modes, reaches >6 million in the Announced Pledges Scenario and >15 million in Net zero Emissions, with most being LDVs. The share of cars within the total FCEV stock remains at about 75% from 2020 to 2030 in the Announced Pledges Scenario, but decreases to 70% in the Net zero Emissions Scenario.

Generally, EVs are expected to be the dominant zero emissions vehicle powertrain in road transport, reflecting higher efficiency and a lower TCO in most cases. FCEV sales in 2030 reach 1% in the Announced Pledges Scenario (compared with 29% for EVs) and 3% in the Net zero Emissions Scenario (against almost 60%) owing to supportive government policies and subsidies, as well as consumer preference for non-cost factors (e.g. refuelling or charging time).

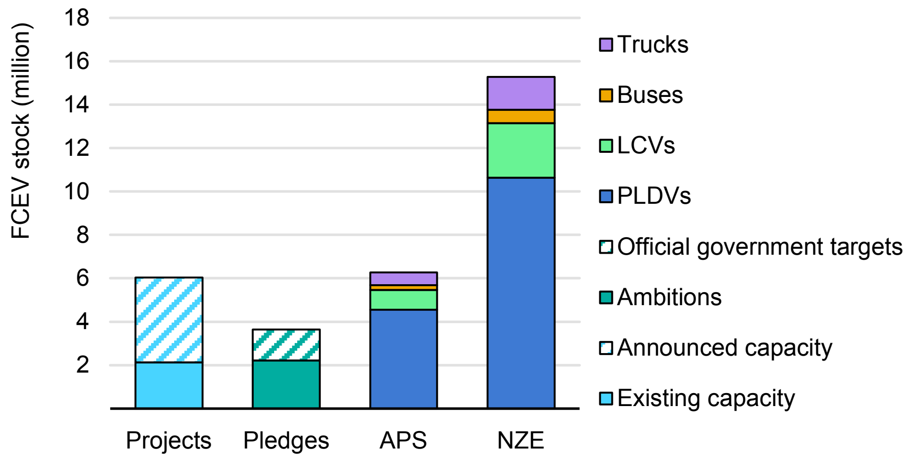
In the Announced Pledges Scenario in 2030, the sales share of fuel cell buses (3.7%) is the highest of all road transport modes, mainly because they offer advantages over battery electric technology for intercity buses. Fuel cells can also compete in the long-haul-trucking sector, as their range, refuelling time and payload capacity can enable performance and operations similar to current diesel trucks.

Similarly, fuel cell buses reach the highest sales share (6.1%) in 2030 in the Net zero Emissions Scenario. In addition, rapid technology and infrastructure development is assumed to support fuel cell truck deployment, which reaches a sales share of 4.7% in 2030. Use of synfuels for road transport is limited due to a higher TCO than for other zero- or low-emission alternatives.

In 2019, the Hydrogen Energy Ministerial published the Global Action Agenda targeting 10 million fuel cell-powered systems (including road vehicles, trains, ships and forklifts) by 2030. Annual fuel cell production capacity doubled from 2019 to 2020, but FCEV deployment in 2020 was ~20% lower than in 2019 – and well below the annual average needed to achieve the target. Even including the deployment of material handling equipment such as forklifts (~10 000 in 2020), accelerated scale-up is needed (likely beyond Announced Pledges projections) to achieve such an ambitious target.

Announced annual fuel cell manufacturing capacity by 2030 (~1.3 million systems/yr) could meet 75% of required fuel cell production for road vehicle sales in the Announced Pledges Scenario but would satisfy only less than one-third of Net zero Emissions sales. Notably, announced capacity exceeds the FCEV stock targets and ambitions stated by governments and other groups (e.g. the China Society of Automotive Engineers and the California Fuel Cell Partnership).

FCEV stock in the Announced Pledges and Net zero Emissions scenarios in 2030 vs current and announced cumulative fuel cell manufacturing capacity and FCEV deployment targets



Notes: FCEV = fuel cell electric vehicle. LCV = light commercial vehicle. PLDV = passenger light-duty vehicle. APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. FCEV ambitions include non-government targets such as from the China Society of Automotive Engineers and the California Fuel Cell Partnership.
Sources: IEA Mobility Model (projections); E4tech (fuel cell projects).

To support FCEV deployment in 2030, an estimated 27 000 HRSs would be needed in the Announced Pledges Scenario and 18 000 in the Net zero Emissions. These estimates are highly sensitive to station capacity and utilisation assumptions. As station size and utilisation are expected to grow more slowly in the Announced Pledges than in the Net zero Emissions Scenario, the former requires a higher number of HRSs despite a lower number of vehicles.

In the Net zero Emissions Scenario, installed station capacity reaches >50 kt/day in 2030, compared with <20 kt/day in the Announced Pledges Scenario.

Non-road transport

Shipping becomes the second-largest consumer of hydrogen and hydrogen-based fuels among transport modes in 2030 in both the Announced Pledges and Net zero Emissions scenarios. Demand for hydrogen and ammonia in shipping remains limited in the Announced Pledges Scenario, together meeting about 1% of fuel demand. In the Net zero Emissions Scenario, ammonia meets 8% of total shipping fuel demand and hydrogen meets 2%.

To enable hydrogen and ammonia fuel use in shipping, ports will need to build corresponding bunkering infrastructure. It is expected that ports with hydrogen bunkering infrastructure will remain fairly limited until 2030, with most being "first movers" such as the signatories of the Global Ports Hydrogen Coalition and others that have already begun investigating and testing hydrogen solutions (e.g. the Port of Valencia, Port of Honolulu, Ports of Auckland, Port of Los Angeles and Port of Antwerp).

As hydrogen continues to displace fossil fuels in relatively short-range vessels (especially when battery electrification is difficult), in the long term every port serving ferries, cruise ships and inland and coastal vessels will likely need hydrogen infrastructure. In the Net zero Emissions Scenario, about ten ports are projected to be first movers in providing ammonia bunkering services (fewer in the Announced Pledges Scenario), all having high maritime cargo throughput and either existing ammonia bunkering or plans to integrate new fuels. Included in the first movers are the ports of Rotterdam and Singapore (both ranking in the top ten by container throughput), as well as the Keihin ports along Japan's Tokyo Bay.

In rail, hydrogen is expected to mainly replace current diesel lines that are expensive to electrify due to relatively low utilisation.[21] Hydrogen constitutes 0.7% of rail energy consumption in 2030 in the Announced Pledges Scenario and 2% in the Net zero Emissions.

Passenger aircraft, for commercial aviation, designed to use hydrogen directly are not expected to be commercially available until the mid-2030s or later. Use of hydrogen-based synfuels (or power-to-liquids [PtL]), which can be dropped into an existing aircraft, could make inroads by 2030. In the Announced Pledges Scenario, PtL meets <0.6% of aviation fuel demand in 2030, but this share almost triples to >1.6% in the Net zero Emissions Scenario.

Given the limited availability of sustainably sourced carbon, the bulk of synfuels are consumed in the aviation sector where battery electrification and direct use of hydrogen are restricted to relatively short flights, especially in the near to medium term.

[21] See The Future of Rail for further analysis.

Transport industry announcements for FCEVs

Company	Target	Target year	Vehicle category
BMW	Limited-series fuel cell SUV release	2022	PLDV
Jaguar Land Rover	Prototype testing of fuel cell SUV	End of 2021	PLDV
Great Wall Motor	Fuel cell SUV release	2021	PLDV
Toyota Motor Corp.	Deployment of 600 FCEV taxis in greater Paris region	End of 2024	PLDV
Riversimple	Production target of 5 000 fuel cell coupes/yr	2023	PLDV
Riversimple	Light goods vehicle model release	2023	LCV
Stellantis	Fuel cell van models release	2021	LCV
Renault and Plug Power	Light commercial vehicle models release	2021	LCV
Symbio and Safra	Availability of 1 500 buses	2021	Bus
Symbio and Safra	Construction of largest EU fuel cell plant (60 000 units/yr)	Unspecified*	Bus
H2Bus Consortium	Deployment of 600 fuel cell buses	2023	Bus
Daimler	Testing of GenH2 truck with liquid hydrogen onboard storage	2021	Truck
Air Products and Cummins	Conversion of ~2 000-truck fleet to hydrogen fuel cells	2022+	Truck
Nikola	Purchase order of up to 800 fuel cell trucks to US Anheauser-Busch	2023+	Truck
MAN	Deployment of hydrogen fuel cell demonstration fleet	2024	Truck
Hyzon	Purchase orders for 1 500 fuel cell trucks to Hiringa Energy in New Zealand; 20 to Jan Baaker and Millenaar & van Schaik in the Netherlands; and 70 to JuVE/MPREIS in Austria	2024	Truck
Hyundai	Purchase order of 1 600 fuel cell trucks to Switzerland	By 2025	Truck
Daimler and Volvo	Large-scale series production of fuel cell trucks	2025+	Truck
Industry Coalition	Deployment of 100 000 heavy-duty fuel cell trucks in Europe	From 2030	Truck

* Although plant construction has already begun, the target date for operations is unspecified.

Notes: PLDV = passenger light-duty vehicle. LCV = light commercial vehicle.

Cost and supply chain analysis

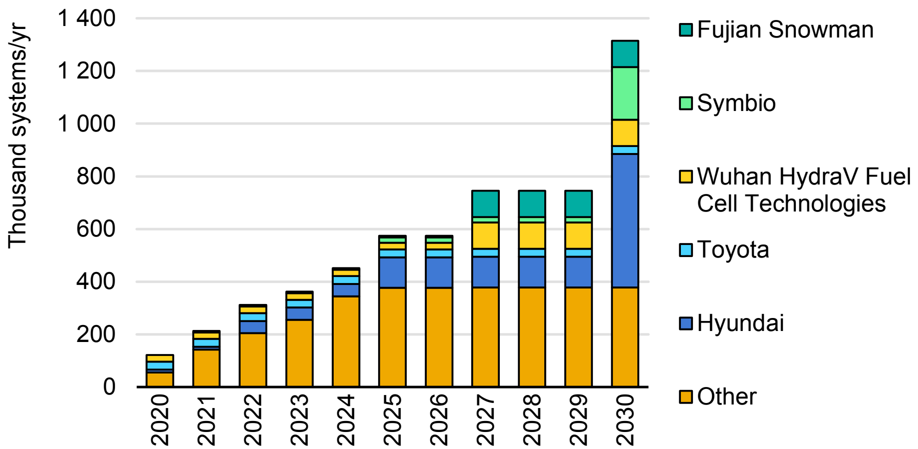
Fuel cells

The cost of automotive fuels cells has [fallen ~70% since 2008](). Depending on the vehicle segment, current system costs are USD 250-400/kW, but further reductions are needed to make FCEVs cost-competitive with internal combustion engine vehicles and other low- or zero emission vehicles. [Analysis]() suggests that scaling up manufacturing capacity from 1 000 to 100 000 systems/yr would slash costs by >70%, but significant investment is needed to boost manufacturing throughput and capacity.

To this end, new and incumbent fuel cell manufacturers have announced expansion plans. Global fuel cell manufacturing capacity is expected to reach >200 000 systems/yr by the end of 2021, with supply spread among over 40 manufacturers. Toyota can currently produce 30 000 systems/yr, and Hyundai is building a second plant to bring capacity to >40 000 systems/yr in 2022 and aims reach 500 000 systems/yr by 2030. Manufacturing capacity announcements for 2030 total 1.3 million systems/yr, with an estimated annual production potential of 90 GW.

Technological advances are needed to improve fuel cell durability (which is particularly vital for heavy-duty transport applications) and reduce costs while maintaining or improving efficiency. Key areas for R&D include the fuel cell catalyst, currently based on platinum group metals; membranes and electrolytes; and bipolar plates.

Announced annual automotive fuel cell manufacturing capacity, 2020-2030



Source: [E4tech]().

Since 2008, average platinum loading in fuel cells has decreased 30%. Toyota reports reducing platinum loading in the Mirai fuel cell by about one-third from first- to second-generation models.

In addition to lowering costs, reducing platinum loading mitigates potential supply chain risks associated with highly geographically concentrated supplies, as more than 70% of platinum group metals are sourced from South Africa.

According to the IEA's critical minerals report, global demand for platinum group metals is expected to grow as FCEVs displace conventional vehicles, though this is mitigated by lower palladium required for ICEV catalytic converters. Overall platinum demand is expected to increase despite further reductions in the platinum loading of automotive fuel cells.

Hydrogen refuelling stations

While economies of scale in station component manufacturing are expected to reduce the delivered cost of hydrogen for vehicles, HRSs with higher capacities will also have a lower levelised cost of dispensed hydrogen. Increasing station size from 350 kg/d to 1 000 kg/d could cut the cost of dispensed hydrogen by over 30%, according to US DOE analysis. As both station capacity and vehicle demand increase, pipeline delivery will become more profitable and could further reduce the overall cost of dispensed hydrogen.

Station utilisation is another important factor. While utilisation tends to align with vehicle deployment, early FCEV fleet deployment can help ensure a certain level of utilisation, lowering hydrogen prices. Stations designed to serve both LDVs and HDVs may be able to increase utilisation and reduce overall capital expenditures, though serving both vehicle types will require more equipment to fuel at different pressures or flowrates.

The number of suppliers for key HRS components is currently limited, which can restrict station roll-out and prevent the cost reductions that come with market competition. For example, just two companies (WEH and Walther) dominate the HRS nozzle market.

Novel component designs (including for high-throughput compressors, cryogenic hydrogen pumps, hoses and nozzles) and refuelling protocols are needed for fast fuelling of heavy-duty trucks, marine vessels and aircraft.

Total cost of ownership

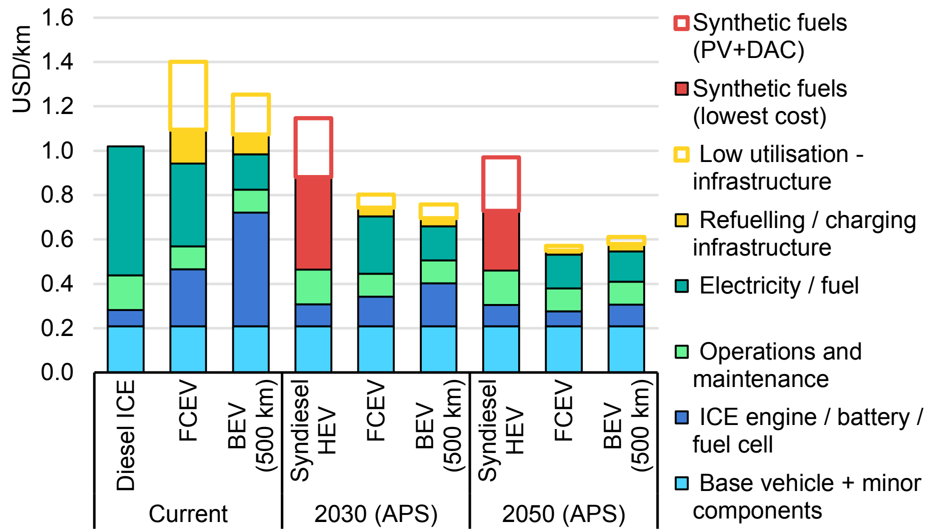
Adoption of FCEVs, especially buses and commercial vehicles, will be determined by how their TCO compares with other vehicle and fuel technologies. The main TCO factors for FCEVs are the delivered hydrogen and fuel cells costs, and station utilisation. In comparison with BEVs, daily range is another key consideration.

For long-haul HDVs, enabling a sufficient driving range may require additional battery capacity; however, the associated weight could limit payload and add to BEV cost. Fuel cell trucks begin to have a TCO advantage over battery electric at a range of 400-500 km, as shown in the IEA's Energy Technology Perspectives 2020.

The TCO for fuel cell heavy-duty trucks is currently 10-45% higher than for internal combustion diesel trucks. In the Announced Pledges Scenario, as the manufacturing of fuel cells, station components and hydrogen production technologies scales up – while station utilisation also increases – the TCO of fuel cell heavy-duty trucks drops 30-40% by 2030 and 50-60% by 2050.

Comparing decarbonisation options for this sector, the TCOs of both battery electric and fuel cell trucks are expected to be lower than for hybrid electric trucks running on synthetic diesel. In the medium term, fuel cell and battery electric trucks have comparable TCOs at a 500-km driving range, depending on refuelling or charging infrastructure utilisation. By 2050 in the Announced Pledges Scenario, fuel cell electric trucks are expected to be the lower-cost option at that range.

Current and future total cost of ownership of fuel/powertrain alternatives for heavy-duty trucks.



Notes: APS = Announced Pledges Scenario. ICE = internal combustion engine. FCEV = fuel cell electric vehicle. BEV = battery electric vehicle. HEV = hybrid electric vehicle. PV = photovoltaic (solar electricity for synthetic fuel production). DAC = direct air capture. Techno-economic assumptions available in the Annex.

Source: Based on input from McKinsey & Company and the Hydrogen Council.

Buildings

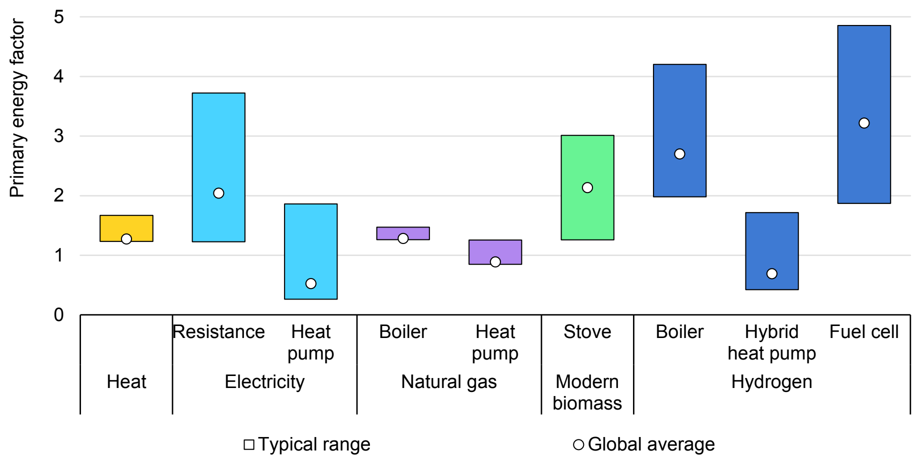
Hydrogen and fuel cell opportunities are limited in buildings but worth exploring

With consumption of almost 70 EJ, space and water heating in buildings accounts for nearly 55% of energy use in buildings globally and 4.3 Gt CO_2 of emissions. In very cold areas such as in Russia, the Caspian region and Iceland, heating can make up >80% of total energy demand in buildings. Improving the thermal performance of building envelopes and integrating clean, efficient low-temperature equipment are priorities to decarbonise heating in buildings. Several options for efficient heating are currently available, including heat pumps and clean district energy.

Prospects for deploying hydrogen in this sector remain limited, reflecting the high efficiency of electricity-based solutions and the energy losses that result from converting and transporting hydrogen. For instance, PV-powered heat pumps require 5-6 times less electricity than a boiler running on electrolytic hydrogen to provide the same amount of heating. Furthermore, ensuring safe operations and converting gas infrastructure are both capital-intensive and socially challenging.

The heating sector is difficult to decarbonise, with existing (old) multi-family buildings and very cold climates being particularly challenging because integrating efficient low-temperature solutions depends on space availability, energy system layout and overall building performance, in addition to logistical and economic costs for building occupants.

Primary energy factors of heat production by equipment and fuel, 2020



Notes: Hybrid heat pumps are assumed to use 25% hydrogen. Heat refers to district heating. Assumptions available in the Annex

Nevertheless, since hydrogen equipment can be compatible with existing buildings' energy systems,[22] localised hydrogen applications

[22] In terms of deliverable temperature range and operational schedules, but pipework, metering and verification interventions are required.

could support decarbonisation in very specific contexts where gas infrastructure already exists. Co-existence of hydrogen and other heat production technologies can also add flexibility to the electricity grid to facilitate demand-side response, particularly in very cold regions where BEVs and other storage devices would likely fall short.

Hydrogen can be blended with or replace a portion of natural gas, which currently meets 35% of global energy demand for heating. Depending on the region, such blending (at volumes of 5-20%) can leverage current natural gas infrastructure without requiring major network modifications.

Blending hydrogen at 20% would reduce carbon intensity by 7% at most – well short of the level needed for long-term buildings sector decarbonisation. It would also affect gas prices for end users. While decarbonising established hydrogen use remains a priority, blending options could help guarantee demand for low-carbon hydrogen.

In the longer term, hydrogen-specific infrastructure could be expanded (by building up dedicated networks or retrofitting existing ones) to further displace natural gas. Space and water heating equipment will also need to be upgraded or replaced, then verified as operational.

Deployment of hydrogen equipment needs to be specifically targeted to applications where it is cost-effective compared with switching to other options, and it takes roughly five days to adapt a building's energy system.

Four main groups of technologies can operate on hydrogen at the building level:

- **Hydrogen boilers** can be practical where gas networks exist because consumers will be familiar with the basic technology and its upfront capital costs. From a lifecycle perspective, however, higher fuel consumption than more efficient technologies makes this option less attractive overall for most buildings.
- **Fuel cells that co-generate**[23] **heat and electricity** include solid oxide fuel cells (SOFCs) and polymer electrolyte membrane fuel cells (PEMFCs). SOFCs require a high temperature but also provide high electrical efficiency and a more stable load compared with PEM cells, which work at a lower temperature (60-80°C) on intermittent load schedules but offer lower electrical efficiency. As SOFC efficiency typically declines when operated with pure hydrogen, optimising the system layout to address this issue is a key research focus. Natural gas field testing in Europe shows micro-cogeneration unit electrical efficiencies of 35-60% for SOFCs and 35-38% for PEMFCs, with corresponding cogeneration system efficiencies of 80-95% (SOFCs) and 85-90% (PEMFCs).

[23] Co-generation refers to the combined production of heat and power, also known as CHP.

- **Hybrid heat pumps** combine a boiler with an electric heat pump. The boiler operates only when the heat pump cannot meet heating demand. Hybrid heat pumps are an interesting option in cold climates where hydrogen can be used to cover peak demand during very cold periods, but they have additional capital costs and require both electricity and hydrogen connections.
- **Gas-driven heat pumps** have a gas engine that produces electricity to run a heat pump. Thousands of units are already operating in Asia and Europe, primarily in non-residential buildings.

Status of hydrogen and fuel cells for buildings

In 2020, hydrogen's share in heating energy demand was extremely limited (at less than 0.005%) even though countries began supporting demonstration projects and programmes to deploy hydrogen-compatible technologies, spark market adoption and reduce upfront consumer costs as early as the 2000s. Largely focused on stationary fuel cells, these programmes have tended to rely on natural gas, but their lessons are applicable to the use of pure hydrogen. These projects are sited in countries that together cover ~40% of global heat demand, with significant heating seasonality and where natural gas covers a large share of heat production in buildings.

Stationary fuel cells

Deployment of micro-cogeneration stationary fuels cells (<1 kW of electrical output [kW_e] for residential applications, and up to 5 kW_e) has been greatest in Japan (more than 350 000 units operating) and Europe, especially in Germany (15 000), Belgium and France. Korea has 15.7 MW_e (units of <100 kW_e) installed in buildings (CEM H2I surveys), while US installations are primarily industrial-scale units (>100 kW_e).

Fuel cells have been deployed in almost all building types – from residential to commercial/public building applications, including military installations, hospitals and data centres – to provide primary or backup power, or co-generation. Most run on natural gas. Fuel cells for residential applications are mostly PEM and tend to be relatively small (0.7-1.5 kW_e but also up to 5 kW_e), with several governments offering financial incentives to support their deployment.

Homeowners in the United States can qualify for federal tax credits (>USD 3 300/kW_e) when installing residential units of >0.5 kW_e. Other government schemes offer subsidies for fuel cell technologies, such as New Jersey's Clean Energy Program for micro-cogeneration technologies. Korea is among the countries using renewable energy certificates and subsidies. Support generally covers the upfront costs of installation, or rewards power generation rather than heat production.

Hydrogen blending and pure hydrogen applications

There are a number of projects around the world at various stages for exploring the impact of hydrogen blending in existing gas networks. Frontrunner, launched in 2007 on the Dutch island of Ameland, tested injection volumes of up to 20% for heating and cooking using standard appliances. More recently in France (June 2018 to March 2021), the GRHYD project tested injection (max. 20%) for >100 dwellings, while the three-phase UK HyDeploy project aims to prove the safety of blending up to 20%. The first phase, concluded in 2021, involved a live demonstration in the Keele gas network to assess what level of blending is safe with existing domestic appliances.

Other initiatives aiming to demonstrate hydrogen use in dedicated networks in a few hundred dwellings are now under development, particularly in north-western Europe. These include H100 Fife (300 households starting in 2022) in the United Kingdom and Hoogeveen and Stad aan 't Haringvliet (600 households from 2025) in the Netherlands. Larger projects, such as the United Kingdom's H21, are at early stages of development.

The UK government also supports the Hy4Heat project to assess the technical, economic and safety aspects of replacing natural gas with hydrogen in residential and commercial buildings and in gas applications. Under this programme, a Worcester Bosch 100% hydrogen-ready prototype boiler – which can be converted to run on hydrogen by modifying just two or three components – won Best Heating Innovation in the 2021 Green Home Awards.

In a first trial in single-family, semi-detached and terraced houses, the project found that 100% hydrogen use is as safe as natural gas for heating and cooking. More research is needed to assess safety in multi-family homes and houses with limited natural ventilation, and to determine the safety of supplying homes through gas networks. The project is also assessing the first home (in Low Thornley, Gateshead) to be entirely fuelled by hydrogen, from boilers to cookers.

The WaterstofWijk Wagenborgen project (in the Netherlands) is a pilot that will connect 1970s buildings to a hydrogen network. Wagerborgen hybrid heat pumps will be installed in each house, running as much as possible on electricity and switching to hydrogen during cold periods only; houses will also be equipped with solar panels and induction cooking.

Natural gas use in the buildings sector and selected key projects, initiatives, programmes, announcements for deploying hydrogen or hydrogen-compatible equipment by country or region, 2020

Region	Share of global heating consumption (%)	Share of water heating in heating consumption (%)	Share of natural gas in:		Initiative details
			Heating (%)	Cooking (%)	
United States	17	19	65	60	New Jersey's Clean Energy Program provides financial incentives for co-generation and fuel cell installations.
United Kingdom	2.5	21	70	50	HyDeploy for hydrogen blending applications. H21 Leeds City Gate and H21 Network innovation for 100% hydrogen application. Hy4Heat project.
Korea	1.5	22	48	63	Announced intentions to create three hydrogen power cities by 2022, in line with hydrogen roadmap goal of providing households and other buildings 2.1 GW of power from fuel cells.
European Union	15	20	40	32	Ene.field project, Europe-wide field trials for residential fuel cells, concluded in 2017. PACE (Pathway to a Competitive European Fuel Cell micro-Cogeneration Market), ends in 2021. ComSos, (Commercial-scale SOFC systems), ends in 2022. National innovation Programme for hydrogen and fuel cell technology (Germany), 2007-16. KfW433 (Germany), dedicated fuel cell programme since 2016; overall impact: >15 000 fuel cells deployed in EU. GRHYD (France): power-to-gas testing with hydrogen blending rates of up to 20% per volume, 2018-21. WaterstofWijk Wagenborgen planned project (Netherlands): demonstration project for hybrid heat pumps for 40 residents.
Japan	3	35	32	39	Ene.Farm project, >350 000 commercial fuel cells deployed.

Notes: Listed projects include concluded as well as ongoing and announced initiatives related to buildings. Heating consumption includes space and water heating.

Regional insights on hydrogen in buildings

Japan

With more than 350 000 units installed as of March 2021, Japan leads global deployment of micro-cogeneration fuel cells in buildings. The ENE-FARM programme is the main contributor to uptake, recently reporting sales of 40 000 units/yr. Models on the market are mostly fuelled by natural gas; most are PEMFC units, but SOFCs have also emerged recently. ENE-FARM subsidies were eliminated in FY2019 for PEMFCs as they reached maturity, but SOFCs remained eligible for subsidies until FY2020 (March 2021).

In 2020, to support the next phase of subsidiary projects and show that fuel cells can be a source for Japan's electricity market, 300 kW of domestic fuel cells were successfully tested to generate electricity at prices similar to those of the electricity retailer. Decarbonising buildings will require a fuel shift for fuel cells, from natural gas to low-carbon gases (such as hydrogen or synthetic methane produced with CO_2 from sustainable sources). Already Panasonic is deploying pure hydrogen fuel cell generators to power streetlights and air conditioning units at the HARUMI FLAG residential complex in Tokyo.

In both the Announced Pledges and Net zero Emissions scenarios, fuel cells in the Japanese market operating on pure hydrogen reach ~1 million installed units by 2030, requiring the development of hydrogen infrastructure.

Korea

The Korean Ministry of Trade, Industry and Energy is currently subsidising fuel cells (as well as solar power and heat, and geothermal and wind energy) to power residential and commercial buildings, with subsidies covering up to 80% of equipment installation costs. As further incentive, the government reduced the price of grid gas used in fuel cells by 6.5% from typical consumer prices, both in buildings and at utility scale.

Total installed stationary fuel cell capacity within buildings was 15.7 MW_e in 2021 according to CEM H2I surveys, largely PEMFC units with capacities ranging from 600 W to 10 kW for residential and commercial buildings. Doosan and S-FuelCell dominate the market, and market attention is shifting towards SOFC units and the use of fuel cells (equivalent to battery power) to boost flexibility in the electricity grid. The Hydrogen Economy Roadmap of Korea targets the cumulative installation of at least 2.1 GW_e of stationary fuel cells by 2040.

Europe

Several European countries are testing fuel cell applications and exploring the technical feasibility of hydrogen blending or pure hydrogen for buildings sector applications. Demonstration projects are ongoing to verify the technology and gain the technical experience necessary to build a regulatory framework.

To date, stationary fuel cell deployment for buildings has been concentrated primarily in domestic units (commercial and industrial systems are less common). The market for fuel cells for residential applications has been supported mainly by projects co-funded by the FCH JU and the European Union, and by the German KfW 433 programme, which aims to enable manufacturers to eventually industrialise this technology.

The ene.field project (concluded in 2017) deployed >1 000 small fuel cell applications (~1.15 MW_e operating on natural gas) in ten countries, in different climates and dwelling types. The subsequent PACE (Pathway to a Competitive European Fuel Cell micro-Cogeneration Market) project aims to deploy >2 800 fuels cells by 2021. In the framework of this project, nearly 740 units were installed in Belgium and more than 710 in Germany.

Commercial-scale units (10-60 kW) are currently being demonstrated through the EU-funded ComSos project, which focuses solely on SOFC units and aims to install 25 in non-residential buildings such as supermarkets.

Germany

With >15 000 units operating, Germany has been the most successful market for stationary fuel cell installations in Europe, according to CEM H2I. Of the >1 000 units demonstrated by the Ene.field project, >750 were installed in Germany.

Fuel cell ramp-up was spurred by Germany's KfW 433 programme, launched in 2016 by the Federal Ministry for Economics and Energy and still ongoing. The programme provides a combination of grants and output-related subsidies of up to USD 3 400 for units with a capacity of 250 W to 5 KW_e, in both new and existing residential and non-residential buildings.

The Netherlands

Although the Netherlands has traditionally relied heavily on natural gas for residential heat, in 2018 the Gas Act was amended to ban gas connections for new homes and buildings. Subsequently, the Natural Gas-Free Districts Programme was implemented to help the country become natural gas-free by 2050. Forty-six municipalities are currently participating as test sites and to map how the transition can be scaled up, with a total of 1.5 million homes to shift from natural gas to low-carbon heating by 2030.

The Netherlands' Government Strategy on Hydrogen and Green Gas Roadmap aim to accelerate large-scale production and use of low-carbon hydrogen and biogas, with the government supporting pilot projects to demonstrate hydrogen. Meanwhile, the Green Deal H2 Neighbourhoods project aims to improve understanding of the techno-economic, safety, social, legal and administrative aspects of using existing gas infrastructure for hydrogen distribution.

Pilot projects in Hoogeven (100 new buildings and 427 existing households converted to run on hydrogen for heating) and Stad aan 't Haringvliet (600 existing buildings disconnected from natural gas by 2025) will help identify barriers and operational needs to scale up hydrogen use in buildings.

United Kingdom

Driving low-carbon hydrogen growth is part of the UK government's Ten Point Plan for a Green Industrial Revolution. To support the buildings sector, it proposes a timescale to have hydrogen heating trials in a neighbourhood by 2023 and to launch larger village trials by 2025, which could lead to a hydrogen town by the end of the decade. Completion of testing to support up to 20% hydrogen injection in the gas network for all homes by 2023 is among the project's target milestones.

In addition to the Hy4Heat and H21 projects (see above), the H100 Fife project (Scotland) intends to deliver an end-to-end 100% hydrogen demonstration using the gas network, to prove its technical viability. Initially, some 300 domestic properties are targeted to be connected and operational for 4.5 years (i.e. until 2027), with each provided with boilers, cookers and hobs.

Another demonstration, the BIG HIT project (Building Innovative Green Hydrogen Systems in Isolated Territories, 2016-2022), is under way in the Orkney Islands (Scotland). Hydrogen produced from local curtailed renewable energy generation on smaller islands is transported to Orkney, where it is used to demonstrate several end-use applications, including heating in buildings. The project is funded by the FCH JU and involves 12 partners from the United Kingdom, Italy, France, Denmark, Spain and Malta.

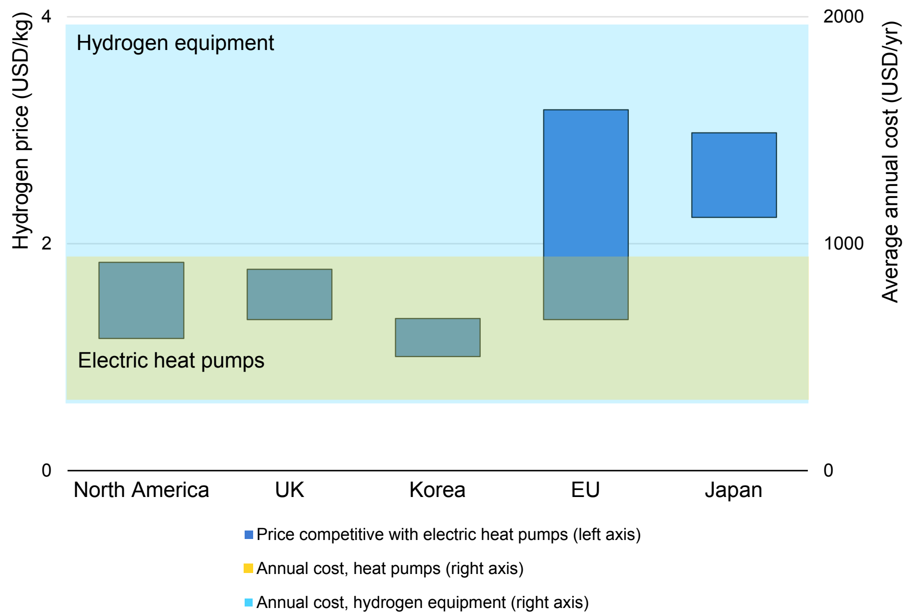
Outlook for hydrogen in building applications

At present, the main markets for fuel cell deployment in buildings are Japan, Europe and Korea, the last having a target of 2.1 GW_e installed by 2040 and focusing mostly on fuel cells for power applications. In these markets, fuel cell deployment is not focused explicitly on hydrogen but more broadly on scaling up and reducing the capital costs of these systems.

Hydrogen uptake in buildings will depend on many factors, including equipment, infrastructure and hydrogen production costs. Competition among direct electrification, hydrogen and district heating affects other factors such as the retrofit potential of buildings; building footprints and heat demand densities; hydrogen and electricity prices in relation to equipment costs; consumer preferences; the potential to supply hydrogen; and requirements for renewable capacity. The flexibility and demand-response potential that hydrogen could provide to energy systems are also key considerations.

In the Announced Pledges Scenario, in major markets hydrogen would need to be priced at USD 0.9-3.5/kg in 2030 to compete with electric heat pumps in buildings. Assuming these price ranges and considering the capital costs of equipment and of using hydrogen equipment in existing buildings, the cost to heat a home of 100 m^2 could range from USD 350/yr to USD 2 000/yr in those markets. This range might be broader than for electric heat pumps due to the wide variability of efficiencies and capital cost of hydrogen equipment.

Potential spread of competitive hydrogen prices and annual cost per household of running heating equipment in selected regions in the Announced Pledges Scenario, 2030



Note: Techno-economic assumptions available in the Annex.

Demonstration projects over the next decade will be vital to define cost uncertainties and better understand the implications of using hydrogen in buildings, ultimately helping to shape solutions for the direct use of pure hydrogen. Testing in dense urban centres will be needed to understand potential barriers, overcome operational constraints, address consumer safety concerns and train operators.

In the Announced Pledges Scenario, heating demand in 2030 is 20% lower than in 2020 thanks to better building envelopes and enhanced equipment efficiency. In parallel, hydrogen demand grows to more than 2 Mt H_2 (around 0.5% of global heat demand) but remains limited as planned actions are not strong enough to accelerate blending in gas networks.

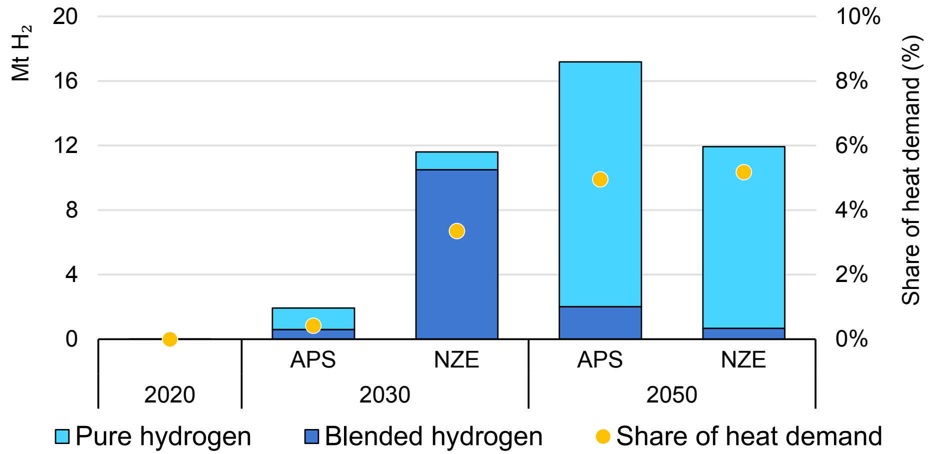
With pure hydrogen applications making inroads post-2030, this share jumps to 5% by 2050. Almost all installations are in existing buildings and are largely aligned with retrofits to ensure that replacing conventional fossil fuel-fired equipment with heat-driven units has minimal impact on building structure and heating distribution systems.

Hydrogen blending rates ramp up much more rapidly by 2050 in the Net zero Emissions than in the Announced Pledges Scenario. Due to its limited decarbonisation potential, blended hydrogen volumes in gas networks decrease after 2030 at the same time as most gas furnaces and boilers are phased out.

In 2050, pure hydrogen makes up 95% of hydrogen demand in buildings – in absolute value lower than in the Announced Pledges Scenario – as larger economies of scale, higher efficiency rates and more developed electricity demand management options are deployed.

In the Net zero Emissions Scenario, hydrogen accounts for 3.5% of final energy use for heating in 2030. Due to its lower efficiency, however, hydrogen meets slightly more than 5% of global heating needs in 2050.

Hydrogen use in buildings and shares of heat demand in the Announced Pledges and Net zero Emissions scenarios, 2020-2050



Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario.

Electricity generation

Greater hydrogen penetration can help expand renewable electricity generation

Current uses of hydrogen in the power sector

Hydrogen use in power generation is negligible at present. It accounts for less than 0.2% of the electricity supply, linked mostly to the use of mixed gases with high hydrogen content from the steel industry, petrochemical plants and refineries, and to the use of by-product pure hydrogen from the chlorine-alkali industry.[24]

Hydrogen can be used as fuel in reciprocating gas engines and gas turbines. Today's reciprocating gas engines can handle gases with a hydrogen content of up to 70% (on a volumetric basis), and various manufacturers have demonstrated engines using 100% hydrogen that should be commercially available in upcoming years.

Gas turbines can also run on hydrogen-rich gases. In Korea, a 45-MW gas turbine at a refinery has been operating on gases of up to 95% hydrogen for 20 years. Manufacturers are therefore confident of delivering standard gas turbines that can run on pure hydrogen by 2030.

A key consideration, however, is that as hydrogen generates a higher combustion temperature than natural gas, its use in gas turbines can drive up NOx emissions, requiring a larger or more efficient selective catalytic reduction (SCR) system to avoid them. Dry, low-emission combustion systems are an alternative to minimise NOx emissions from hydrogen in gas turbines, and systems with up to 50% hydrogen blends have been demonstrated.

Fuel cells can convert hydrogen into electricity and heat, producing water but no direct emissions. Fuel cell systems can achieve high electrical efficiencies (over 60%) and can maintain high efficiency even operating at part load, making them particularly attractive for flexible operations such as load balancing.

The main fuel cell technologies for electricity and heat generation are:

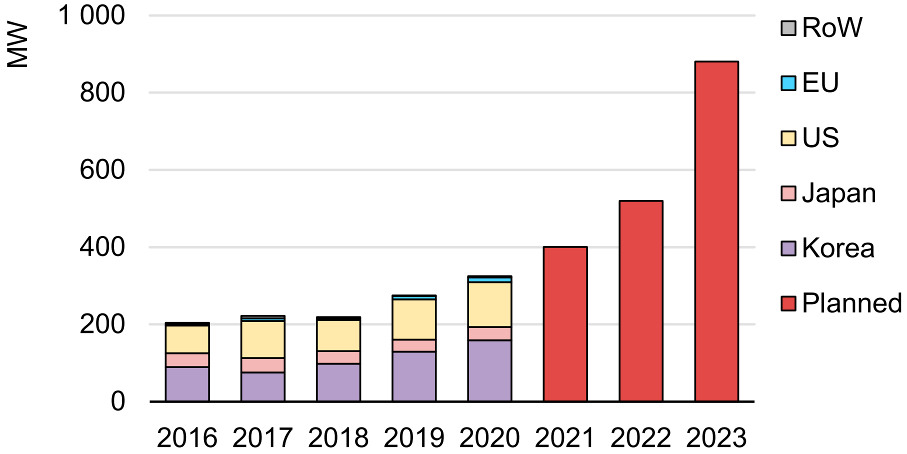
- **Polymer electrolyte membrane fuel cells (PEMFCs),** which operate at low temperatures and are used as micro-cogeneration units.
- **Phosphoric acid fuel cells (PAFCs),** used as stationary power generators with outputs in the range of 100-400 kW.
- **Molten carbonate fuel cells (MCFCs)** and **solid oxide fuel cells (SOFCs**), which operate at higher temperatures (600°C and 800-1 000°C, respectively) and can be used for heating and cooling in buildings and industry.

[24] Though mentioned here, the hydrogen content of mixed gases and by-product hydrogen from the chlorine-alkali industry are generally not included in hydrogen supply and demand presented in this report.

- **Alkaline fuel cells (AFCs),** which operate at low temperatures and can be used in stationary applications, although very few units have been deployed to date.

Global installed capacity of stationary fuel cells has grown rapidly over the past ten years, reaching ~2.2 GW in 2020. At present, only 150 MW use hydrogen as fuel; most run on natural gas. Of the 468 000 units installed globally, micro-cogeneration systems dominate. Japan's ENE-FARM initiative accounts for the majority, with 350 000 such systems.

Stationary fuel cell capacity deployment, 2016-2023



Notes: EU = European Union; RoW = rest of world: US = United States. Data for 2020 estimated based on Q1-Q3 information. Planned capacity (2021-23) based on capacity increases and historic trends.
Source: E4tech.

Stationary fuel cells can also provide backup power (e.g. for data centres and hospitals) and off-grid electricity, applications that currently rely on diesel generators. As switching to fuel cells can reduce local air pollution and eliminate the need to potentially import diesel, many countries use fuel cells with a capacity of a few kW, fuelled by methanol, liquefied petroleum gas (LPG) or ammonia, as backup or off-grid electricity for radio and telecom towers. In 2020, Ballard Power was awarded a contract for 500 fuel cell systems for digital radio towers in Germany to ensure backup power for 72 hours.

Ammonia could also become a low-carbon fuel option for the power sector, either through imports to countries with limited options for low-carbon dispatchable generation or by being used as a medium to store electricity over longer periods to balance seasonal variations in renewable electricity supplies or electricity demand. Ammonia can be converted to hydrogen for use in gas turbines, used directly in internal combustion engines or fuel cells (AFCs and SOFCs), or fed into coal power plants in a co-firing arrangement.

Co-firing a 1% share of ammonia was successfully demonstrated by Chugoku Electric Power Corporation (Japan) at a commercial coal-fired power station in 2017. JERA, Japan's largest utility company, has started work on demonstrating a 20% co-firing share of ammonia at a 1-GW coal-fired unit, with the aim of completing tests by 2025.

To date, the direct use of ammonia has been successfully demonstrated only in micro gas turbines (up to 300 kW capacity). Its low combustion speed and flame stability issues have been identified as barriers to using ammonia in larger gas turbines (along with increased NOx emissions). However, Mitsubishi Power recently announced plans to commercialise a 40-MW gas turbine directly combusting 100% ammonia by around 2025.

Hydrogen and hydrogen-based fuels (such as ammonia and liquid organic hydrogen carriers) also offer seasonal and large-scale storage options for the power sector. While being immensely more cost-effective, these options have low round-trip efficiencies (around 40%) compared with batteries (around 85%), limiting their use for storing energy over longer periods.

Salt caverns, being well sealed and having low contamination risk, are already used to store pure hydrogen underground (see Chapter Infrastructure and trade). Alternately, hydrogen-based fuels (e.g. ammonia) can be used for storage in regions lacking access to salt caverns – i.e. surplus electricity can be converted to ammonia, which can be burned in power plants when solar PV and wind generation drop.

Another option is the large, refrigerated liquid ammonia tanks (e.g. 50-m diameter and 30-m height) typically used in the fertiliser industry, which can store 150 GWh of energy, comparable to the annual electricity consumption of a city of 100 000. Siemens demonstrated the use of ammonia for electricity storage in 2018 in the United Kingdom, using electrolysis to convert wind electricity into hydrogen and then into ammonia for storage. The stored ammonia was later burned in an internal combustion engine as needed to produce electricity.

Future hydrogen trends

Very few countries have explicit targets for using hydrogen or hydrogen-based fuels in the power sector. Japan is one of the exceptions: it aims to use 0.3 Mt H_2/yr in electricity generation by 2030, corresponding to 1 GW of power capacity, rising to 5-10 Mt H_2/yr (15-30 GW) in the longer term. Meanwhile, Korea's hydrogen roadmap targets 1.5 GW of installed fuel cell capacity in the power sector by 2022 and 8 GW by 2040.

Several countries recognise hydrogen's potential as a low-carbon option for co-generation and for providing flexibility as they reach high shares of variable renewable power. Germany's National Hydrogen Council's action plan envisions 0.6 Mt H_2 of power sector hydrogen demand by 2030, increasing to 9 Mt H_2 by 2040.

Co-firing with hydrogen and ammonia can be a means to reduce the emissions of existing gas- and coal-fired power plants in the near term. In the longer term, as variable renewable energy shares increase, hydrogen- and ammonia-fired power plants can be a low-carbon flexibility option.

Capacity linked to hydrogen-based fuels reaches 30 GW by 2030 and 480 GW by 2050 in the Announced Pledges Scenario, and 140 GW (by 2030) and 1 850 GW (by 2050) in the Net zero Emissions Scenario. Still, in 2050, hydrogen-based fuels account for only 1-2% of total global generation in the two scenarios. With modest additional investments (but relatively high fuel costs), co-firing of hydrogen-based fuels is targeted towards reinforcing power system stability and flexibility rather than providing bulk power.

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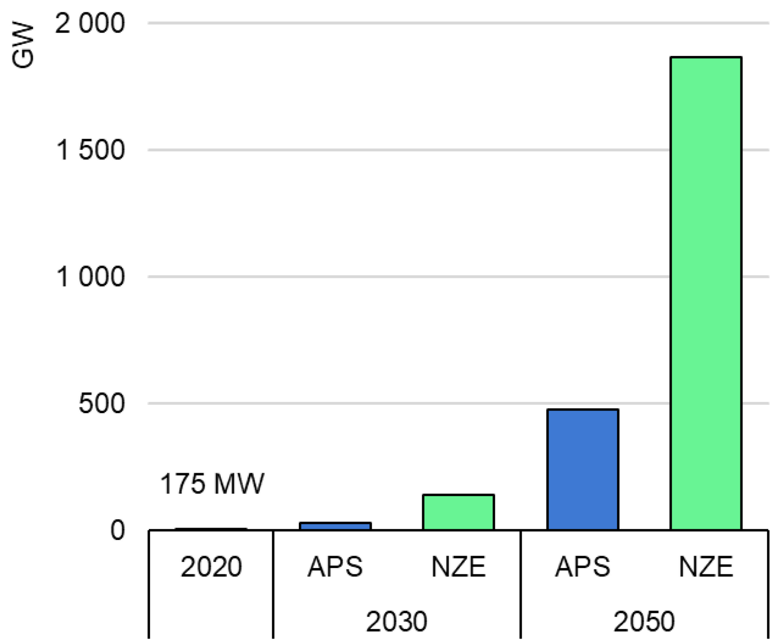
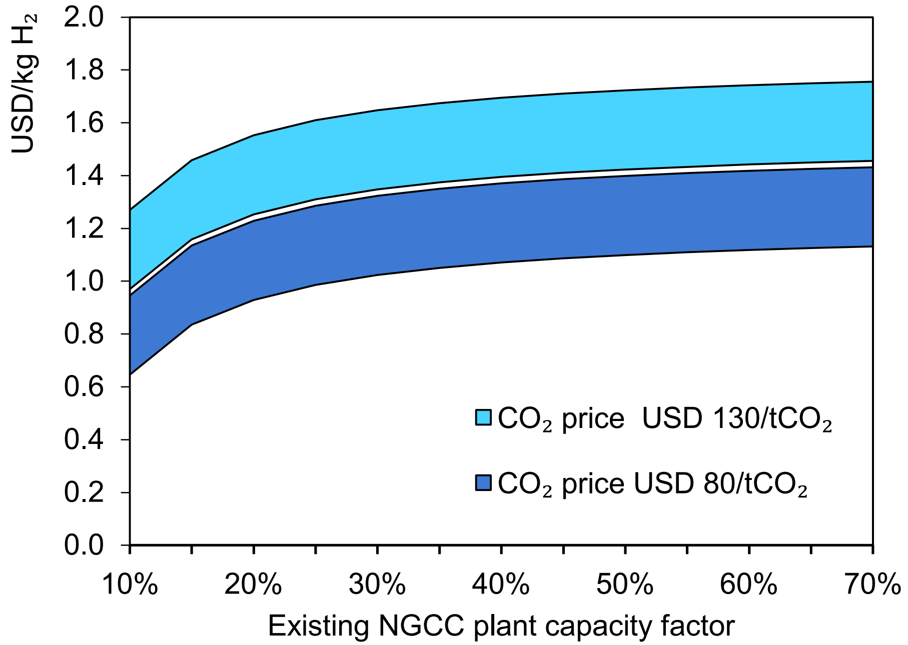
Hydrogen- and ammonia-fired electricity generation capacity in the Announced Pledges and Net zero Emissions scenarios, 2020-2050



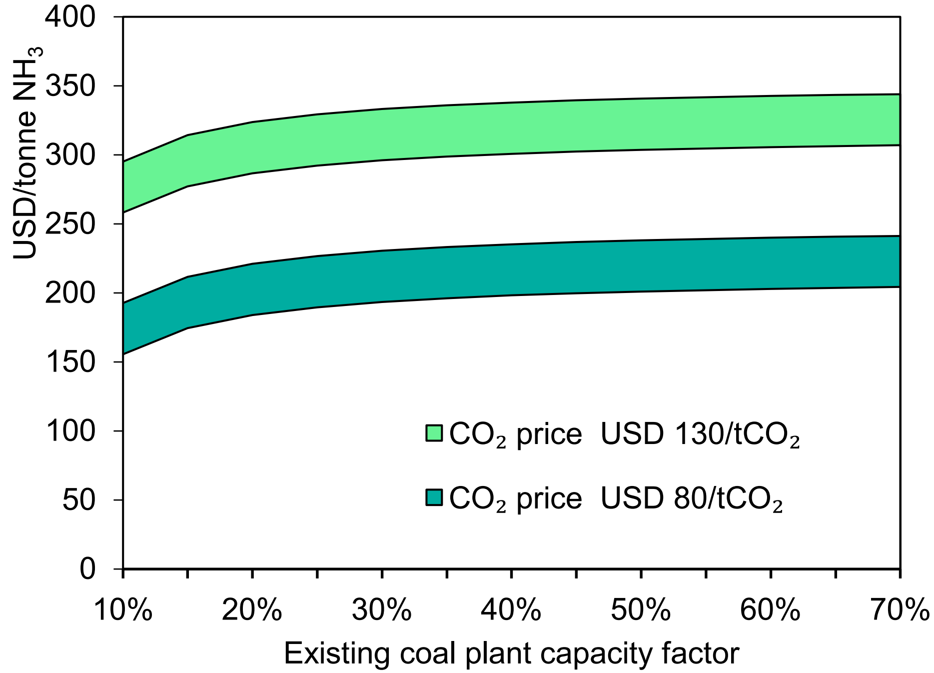
Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario.

Economic analysis of co-firing hydrogen and ammonia in fossil fuel power plants

Break-even hydrogen price for an existing natural gas power plant, 2030



Break-even ammonia price for an existing coal power plant, 2030



Notes: NGCC = natural gas combined cycle. Techno-economic assumptions available in the Annex.

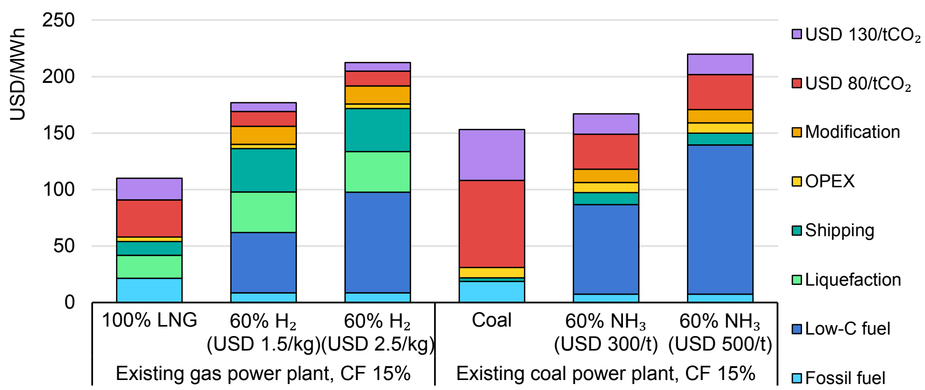
A basic condition must be met to make switching to low-carbon fuel economically attractive for existing thermal power plants: the combined cost of required plant modifications and of low-carbon fuel must be lower than the combined cost of the fossil fuel and any penalties for CO_2 emissions from combustion. Due to coal's higher carbon content, coal plants are more sensitive to carbon prices than natural gas plants, but both cases would require very high carbon prices and/or cheap low-carbon fuels to incentivise a switch. While relatively small modifications are required to enable co-firing of hydrogen or ammonia in existing gas or coal power plants, the cost of such modifications is more consequential if power plants operate at low capacity factors. However, the value of the energy produced can be much higher when operations are similar to peaking plants, which can compensate for the increased costs.

In some cases, fuel transport costs also affect overall co-firing costs significantly. This is especially the case for waterborne transport of hydrogen, which is currently at a low technology readiness level and requires expensive preparation (e.g. liquefaction). Similar cost impacts are associated with transporting natural gas as liquefied natural gas (LNG), although they are moderated somewhat by the wider availability of large-scale LNG tankers and the higher liquefaction temperature of natural gas (compared with hydrogen), which requires less energy.

Ammonia (compared with hydrogen and natural gas) has the highest vaporisation temperature, and the commercial availability of ammonia ship carriers makes transport costs lower. Although converting hydrogen to ammonia incurs thermal losses and greater capital investment, if marine transport is required, the higher levelised cost of ammonia (compared with hydrogen) can be offset (in part or fully) by lower transportation costs.

Despite the costliness of low-carbon hydrogen and ammonia, high carbon prices can largely counterbalance the additional cost of co-firing by reducing CO_2 emissions and associated carbon price penalties. This is especially the case for existing coal-fired plants. The IEA's forthcoming report The Role of Low-Carbon Fuels in Clean Energy Transitions of the Power Sector will provide more details on the potential use of hydrogen and ammonia in electricity generation.

Existing thermal power plants' levelised cost of energy with co-firing, 2030



Notes: LNG = liquefied natural gas. CF = capacity factor. Low-C fuel = low-carbon fuel. Techno-economic assumptions available in the Annex.

Electricity sector hydrogen projects under development

Power plant/project	Location	Start-up date	Capacity (MW)	Description
Daesan Green Energy	Korea	2020	50	PAFCs fuelled by by-product hydrogen from petrochemical industry
Long Ridge Energy Terminal	US	2021	485	Initially blending 15-20% hydrogen with natural gas at new CCGT; moving to 100% hydrogen in next 10 years
Magnum	Netherlands	2023	440	Conversion of existing natural gas-fired CCGT; hydrogen from natural gas + CCUS; currently on hold
Keadby Hydrogen	United Kingdom	2030	1 800	Being developed together with Keadby 3, a natural gas-fired power plant + CCUS
JERA-Hekinan	Japan	2024	200	20% co-firing of ammonia in 1-GW Unit 4 of coal-fired Hekinan power plant
Air Products' Net zero Hydrogen Energy Complex	Canada	n.a.	n.a.	Hydrogen produced from natural gas-fuelled ATR + CCUS
Ulsan	Korea	2027	270	Conversion of CCGT from natural gas to hydrogen
Hyflexpower	France	2023	12	Combining hydrogen production from renewables, hydrogen storage and electricity generation from hydrogen in a gas turbine
Intermountain Power Project	United States	2025	840	Conversion of a 1.8-GW coal power plant into 840-MW CCGT with gradually increasing hydrogen co-firing, from 30% in 2030 to 100% by 2045

Notes: ATR = autothermal reformer. CCGT = combined-cycle gas turbine.

Hydrogen supply

Overview and outlook

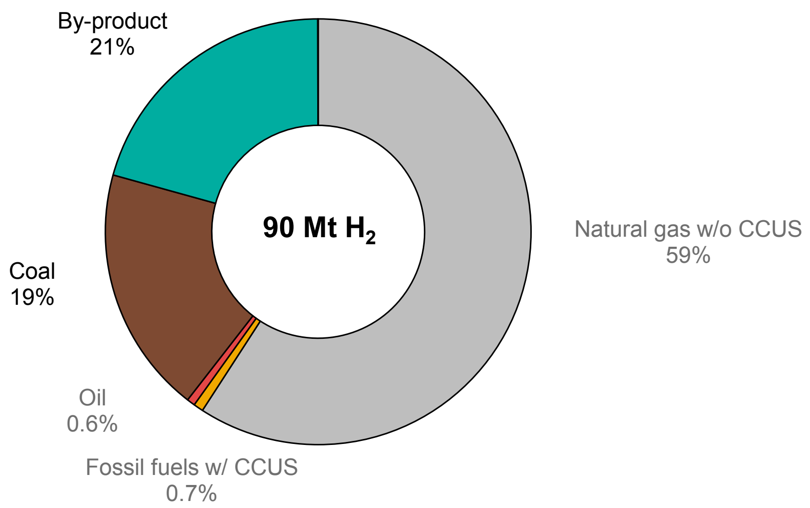
Hydrogen production in 2020

Global hydrogen demand of 90 Mt in 2020 was met almost entirely by fossil fuel-based hydrogen, with 72 Mt H_2 (79%) coming from dedicated hydrogen production plants. The remainder (21%) was by-product hydrogen produced in facilities designed primarily for other products, mainly refineries in which the reformation of naphtha into gasoline results in hydrogen. Pure hydrogen demand, mainly for ammonia production and oil refining, accounted for 72 Mt H_2, while 18 Mt H_2 was mixed with other gases and used for methanol production and DRI steel production.

Natural gas is the main fuel for hydrogen production, with steam methane reformation being the dominant method in the ammonia and methanol industries, as well as in refineries. Using 240 bcm (6% of global demand in 2020), natural gas accounted for 60% of annual global hydrogen production, while 115 Mtce of coal (2% of global demand) accounted for 19% of hydrogen production, reflecting its dominant role in China. Oil and electricity fuelled the remainder of dedicated production.

The dominance of fossil fuels made hydrogen production responsible for almost 900 Mt of direct CO_2 emissions in 2020[25] (2.5% of global CO_2 emissions in energy and industry), equivalent to the emissions of Indonesia and the United Kingdom combined. For a clean energy transition, emissions from hydrogen production must be reduced.

Sources of hydrogen production, 2020



Note: CCUS = carbon capture, utilisation and storage.

[25] This includes 265 Mt CO_2 emitted through the use of hydrogen-derived products (e.g. urea and methanol) that capture carbon only temporarily.

Various technology options exist to produce low-carbon hydrogen: from water and electricity via electrolysis; from fossil fuels with carbon capture, utilisation and storage (CCUS); and from bioenergy via biomass gasification. However, they account for very small shares of global production: at 30 kt H_2, water electrolysis made up ~0.03%, and 16 fossil fuel with CCUS plants produced just 0.7 Mt H_2 (0.7%).[26]

Water demand for hydrogen production

In addition to energy, hydrogen production requires water. Water electrolysis has the smallest water footprint, using about 9 kg of water per kg of hydrogen. Production from natural gas with CCUS pushes water use to 13-18 kg H_2O/kg H_2, while coal gasification jumps to 40-85 kg H_2O/kg H_2, depending on water consumption for coal mining.

In the Net zero Emissions Scenario, global water demand for hydrogen production reaches 5 800 mcm, corresponding to 12% of the energy sector's current water consumption. While total water demand for hydrogen production is rather low, individual large-scale hydrogen production plants can be significant consumers of fresh water at the local level, especially in water-stressed regions.

Using seawater could become an alternative in coastal areas. While reverse osmosis for desalination requires 3-4 kWh of electricity per m^3 of water, costing around USD 0.70-2.50 per m^3, this has only a minor impact on the total cost of water electrolysis, increasing total hydrogen production costs by just USD 0.01-0.02/kg H_2. As the direct use of seawater in electrolysis currently corrodes equipment and produces chlorine, various research projects are investigating ways to make it easier to use seawater in electrolysis in the future.

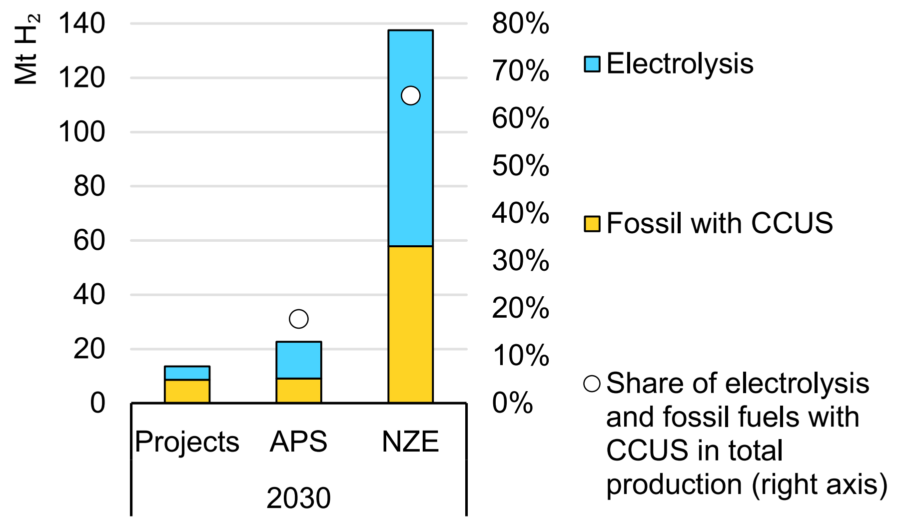
[26] These include facilities that produce pure hydrogen and capture CO_2 for geological storage or sale; CO_2 captured from ammonia plants for use in urea manufacturing is excluded.

Low-carbon hydrogen production projects are multiplying rapidly, but fall short of climate ambitions

Judging by projects under construction or planned, low-carbon hydrogen production could grow rapidly to 2030.[27] Some 350 projects could push electrolytic hydrogen production to 5 Mt H_2, while 56 projects for fossil fuels with CCUS could reach 9 Mt H_2 (including the 16 existing plants). Taking into account another 40 projects at an early development stage, electrolytic hydrogen production could reach 8 Mt H_2 by 2030.

Although production from electrolysers falls far short of the 12 Mt H_2 needed in the Announced Pledges Scenario in 2030, the 9 Mt H_2 from natural gas with CCUS is on target. Together, however, expected production from planned projects is only two-thirds of what is needed. This gap widens significantly in the Net zero Emissions Scenario, which requires electrolytic hydrogen production of 80 Mt H_2 and 60 Mt H_2 from natural gas with CCUS in 2030. Nevertheless, more projects are likely to be developed in upcoming years, reducing shortcomings of the current project pipeline.

Electrolysis and fossil fuel + CCUS hydrogen production in the Projects case, Announced Pledges and Net zero Emissions scenarios, 2030



Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. CCUS = carbon capture, utilisation and storage. Hydrogen from fossil fuels with CCUS does not include production that uses the CO_2 to produce urea; this production totals 13 Mt H_2 in 2030 in both the APS and NZE.

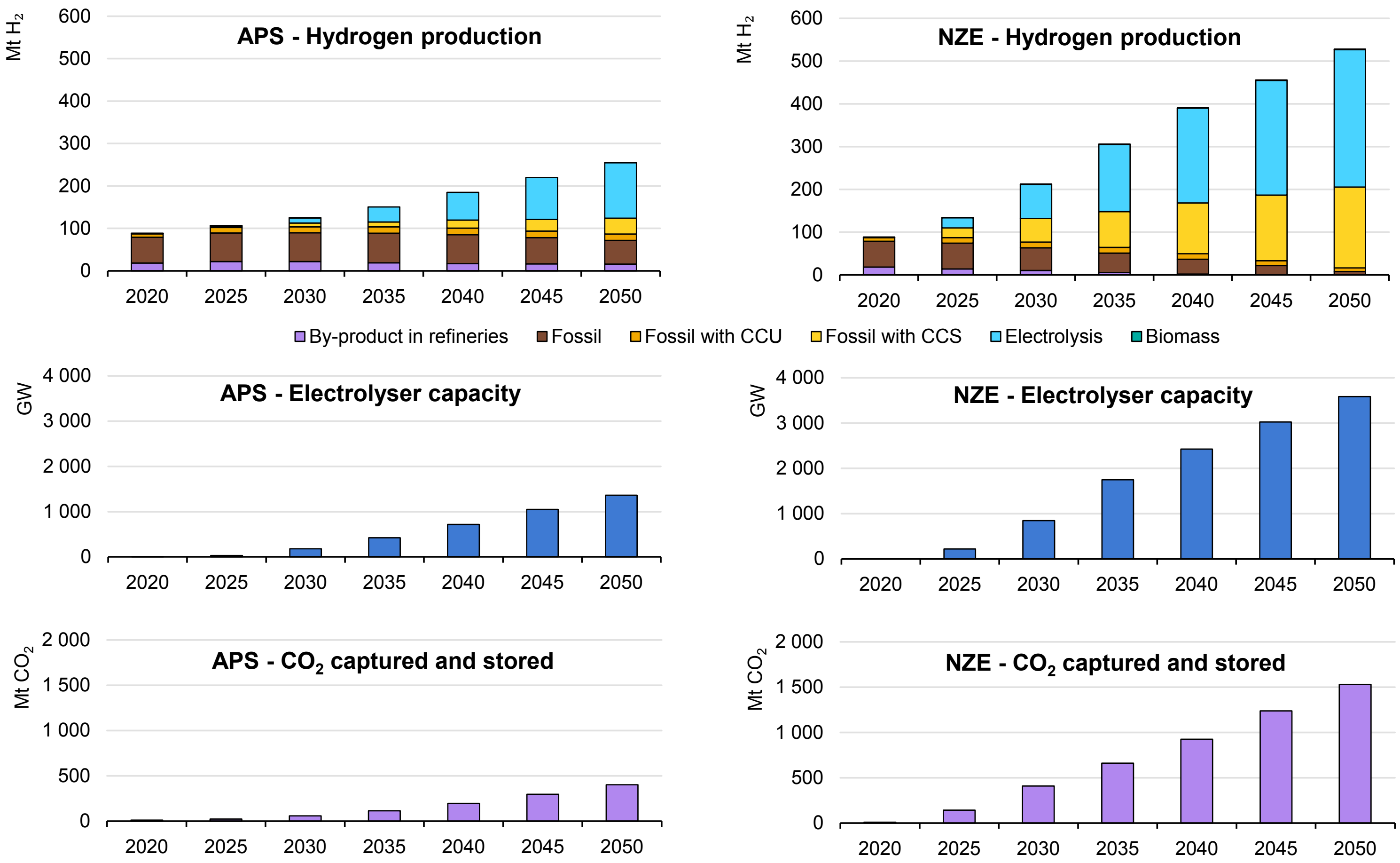
[27] If not otherwise specified, planned projects are those for which a final investment decision (FID) has been taken or a feasibility study is in progress.

By 2050, global hydrogen production reaches 250 Mt H_2 in the Announced Pledges Scenario, with 51% provided by electrolysis, 15% by fossil fuels with CCUS and the remainder by fossil fuels without CCUS. This corresponds to global electrolyser capacity of 1 350 GW and the capture of 0.4 Gt CO_2/yr.

In the Net zero Emissions Scenario, global production doubles compared to the Announced Pledges Scenario, with shares of 60% from electrolysis and 36% from fossil fuels with CCUS as installed electrolyser capacity reaches 3 600 GW and the capture rate climbs to 1.5 Gt CO_2/yr. Notably, this corresponds to electricity consumption of almost 15 000 TWh (20% of global generation) and 925 bcm of natural gas (50% of global natural gas demand).

Decarbonising hydrogen production will require rapid electrolysis and CCUS roll-out

Global hydrogen production, installed electrolysis capacity and CO_2 captured and stored in the Announced Pledges and Net zero Emissions scenarios



Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. CCS = carbon capture and storage; CCU = carbon capture and use. Hydrogen production from fossil fuels with CCU refers to ammonia production in which captured CO_2 is used to produce urea fertiliser. When urea fertiliser is applied to soil, it breaks down again into ammonia and CO_2, with the latter released into the atmosphere.

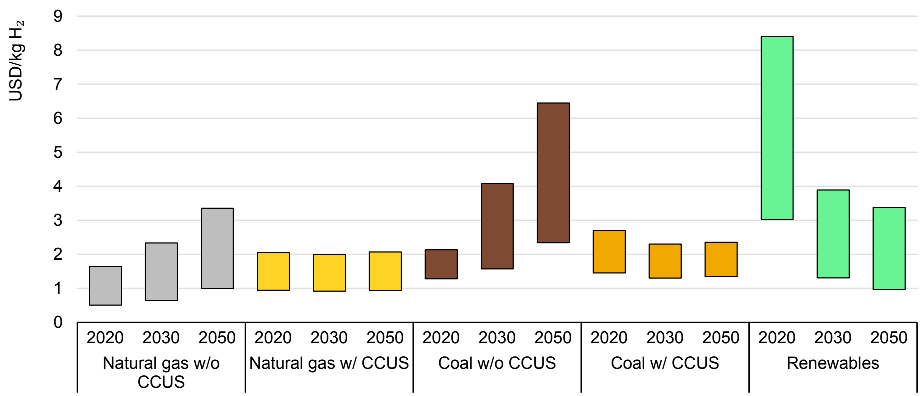
The cost challenge of low-carbon hydrogen

In most parts of the world, producing hydrogen from fossil fuels is currently the lowest-cost option. Depending on regional gas prices, the levelised cost of hydrogen produced from natural gas is in the range of USD 0.50-1.70/kg H_2. Using renewables is much costlier in most places, at USD 3.00-8.00/kg H_2. In fact, renewable electricity costs can make up 50-90% of total production expenses, depending on both electricity costs and the full-load hours of the renewable electricity supply.

As both renewable electricity and electrolyser costs fall, however, the price gap between production methods is expected to shrink quickly. Pricing CO_2 emissions (e.g. through carbon prices) could further narrow the gap by pushing up the cost of hydrogen produced from fossil fuels. For example, a carbon price of USD 100/t CO_2 corresponds to a cost increase of USD 0.90/kg H_2 for natural gas-based production without CCUS, or USD 2.00/kg H_2 for coal gasification without CCUS.

At high capture rates (90-95%), the impact of CO_2 prices on hydrogen production costs from fossil fuels with CCUS can be drastically reduced. Depending on gas prices, natural gas with CCUS entails a production cost of USD 1.00-2.00/kg H_2 – about USD 0.50/kg H_2 higher than without CCUS. A CO_2 price of USD 70/t CO_2 would therefore be needed to close this cost gap.

Levelised cost of hydrogen production by technology in 2020, and in the Net zero Emissions Scenario, 2030 and 2050



Notes: CCUS = carbon capture, utilisation and storage. Ranges of production cost estimates reflect regional variations in costs and renewable resource conditions.
Sources: Based on data from McKinsey & Company and the Hydrogen Council; IRENA (2020); IEA GHG (2014); IEA GHG (2017); E4Tech (2015); Kawasaki Heavy Industries; Element Energy (2018).

Meanwhile, reducing the cost of low-carbon electricity will be critical to bring down the expense of producing hydrogen from electrolysis. Hydrogen production costs of USD 1.00/kg H_2 – the 2030 goal of the US Hydrogen Earthshot initiative – translate into electricity prices of USD 20/MWh, without any CAPEX or fixed OPEX (at 70% efficiency, lower heating value). To reach this targeted hydrogen production cost, electricity prices must therefore be sufficiently below USD 20/MWh to allow for additional CAPEX and OPEX costs.

In regions with good solar resources – and thus relatively high full-load hours for the electrolyser – solar PV can fall below this cost threshold. In fact, tenders for utility-scale solar PV in the Middle East in 2019 and 2020 secured bids of USD 14-17/MWh (though these prices are very market-specific and reflect favourable financing conditions).

Furthermore, technology improvements to boost electrolyser efficiency moderate how electricity costs affect hydrogen production costs. Efficiency improvements are not limited to the electrolyser itself; optimising components such as rectifiers and inverters for anticipated operation at part load (i.e. not nominal load) is vital if variable renewables are the main electricity source. The projected cost of hydrogen production after 2030 is therefore very uncertain and will depend on the impacts of scaling up, learning by doing and other technological progress.

Electrolysis

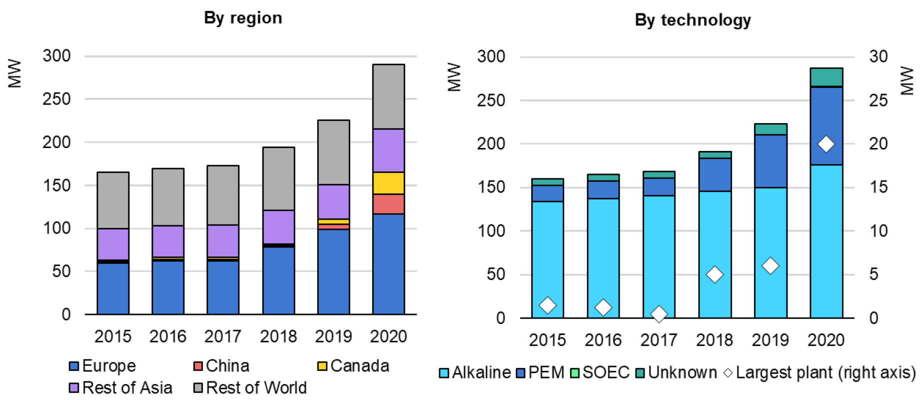
Electrolysis deployment is expanding quickly

Water electrolysis is an electrochemical process that uses electricity to split water (H_2O) into hydrogen (H_2) and oxygen (O_2). In 2020, this process accounted for ~0.03% of hydrogen production for energy and chemical feedstocks.[28] Of installed global electrolyser capacity of 290 MW, more than 40% is based in Europe with the next-largest capacity shares in Canada (9%) and China (8%).

Four main electrolyser technologies exist today: alkaline; proton exchange membrane (PEM); solid oxide electrolysis cells (SOECs); and anion exchange membranes (AEMs) (see Emerging Technologies below for more on SOECs and AEMs). Alkaline electrolysers dominate with 61% of installed capacity in 2020, while PEMs have a 31% share. The remaining capacity is of unspecified electrolyser technology and SOECs (installed capacity of 0.8 MW).

Used since the 1920s for hydrogen production in the fertiliser and chlorine industries, alkaline electrolysis is a mature commercial technology. The operating range of alkaline electrolysers covers a minimum load of 10% to full design capacity. As they do not require precious materials, capital costs are relatively low compared with other electrolyser technologies.

Global installed electrolysis capacity by region and technology, 2015-2020



Notes: PEM = proton exchange membrane; SOEC = solid oxide electrolysis cell.
Source: IEA (2021), Hydrogen Projects Database.

The area requirements of PEM electrolyser systems are relatively small, making them potentially more attractive than alkaline electrolysers in dense urban or industrial areas. Current materials for electrode catalysts (platinum, iridium), bipolar plates (titanium) and membrane materials are expensive, however, so overall costs for

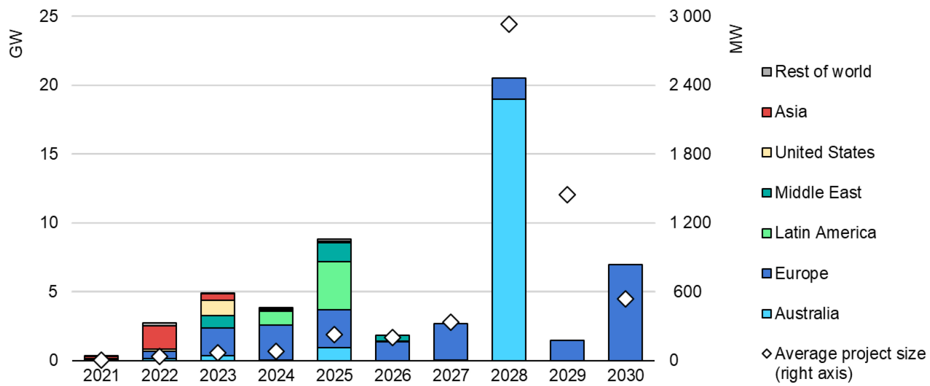
[28] If not otherwise specified, electrolysis refers to water electrolysis, i.e. excluding chlor-alkali electrolysis.

PEMs (USD 1 750/kW) are higher than for alkaline electrolysers (USD 1 000-1 400/kW). Additionally, PEM systems currently have a shorter lifespan.

By 2030, global installed electrolyser capacity could climb to 54 GW, given capacity under construction and planned. If all projects at the very early planning stages are counted, capacity could even reach 91 GW by 2030. Geographically, Europe and Australia lead with 22 GW[29] and 21 GW of projects under construction or planned, followed by Latin America (5 GW) and the Middle East (3 GW).

Many projects are linked to renewables as a dedicated electricity source, and around a dozen demonstration projects (combined electrolyser capacity of 250 MW) explore using nuclear power for hydrogen production (Canada, China, Russia, the United Kingdom and the United States). Not all these projects will be realised, however. So far, only 4 GW (7%) are linked to projects under construction or with a final investment decision, leaving 50 GW still at various earlier stages of development (e.g. at the front-end engineering design, feasibility study and concept phases).

New installed electrolyser capacity based on projects under construction or planned, 2021-2030



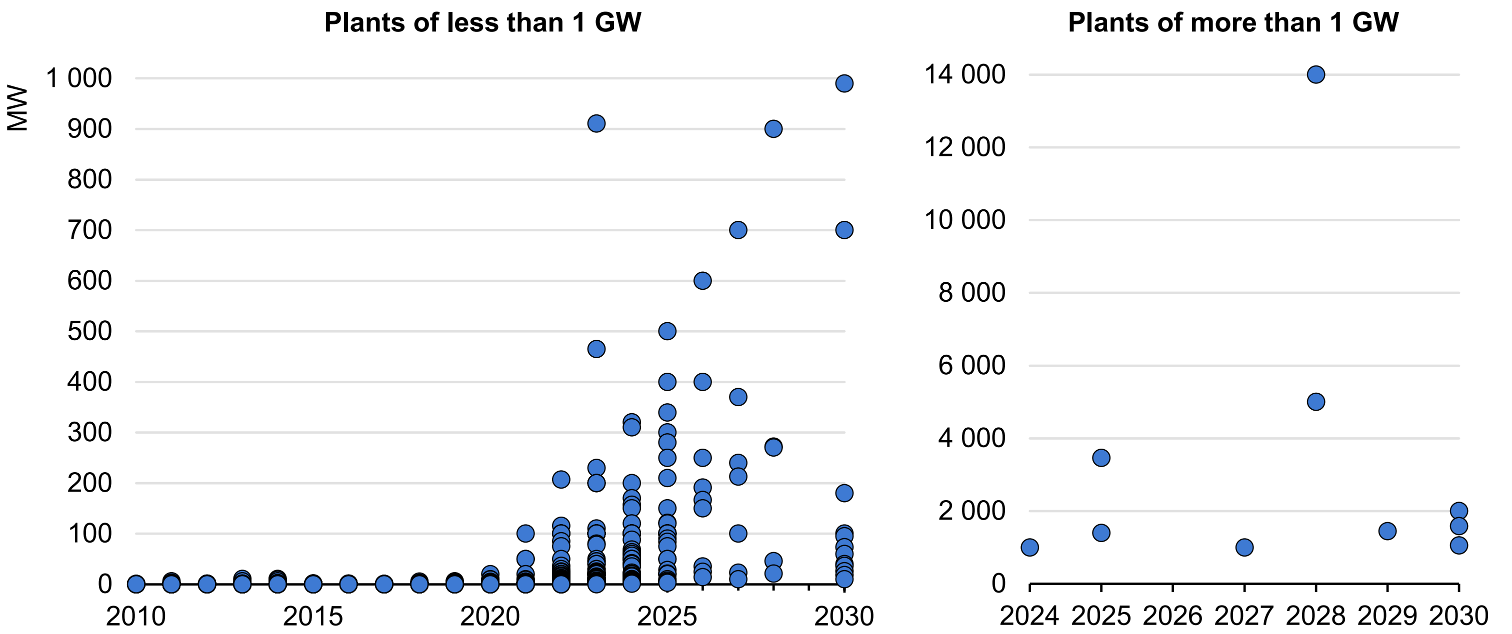
Notes: Based on ~350 projects under construction or planned. Only projects with a known start year of operation are considered.
Source: IEA (2021), Hydrogen Projects Database.

As global electrolyser capacity scales up, the average project size increases. Notably, the average of 0.6 MW in 2020 includes the largest alkaline electrolyser plant in operation (the 25-MW Industrial Cachimayo plant in Peru, which is connected to the electricity grid) and the largest PEM electrolyser plant in operation using dedicated renewables (20 MW using hydropower, inaugurated in 2020 by Air Liquide in Bécancour, Canada).

[29] For Europe, some projects with unknown completion dates (e.g. the 67-GW HyDeal project) are not included. If realised, they could push electrolyser capacity well beyond 23 GW by 2030.

Some 80 projects under construction or being planned have capacities of >100 MW, and 11 projects reach ≥1 GW. The planned Western Green Energy Hub (Australia) is in the GW scale: with a solar PV and wind capacity of up to 50 GW, it will produce 3.5 Mt H_2/yr for conversion into 20 Mt of ammonia for export. As the average project size increases to 230 MW by 2030, economies of scale and learning effects are expected to bring down electrolyser costs.

Size of electrolyser projects (existing, under construction and planned), 2010-2030



Note: Years refer to the planned start of operations; only projects with a known start year are considered.
Source: IEA (2021), Hydrogen Projects Database.

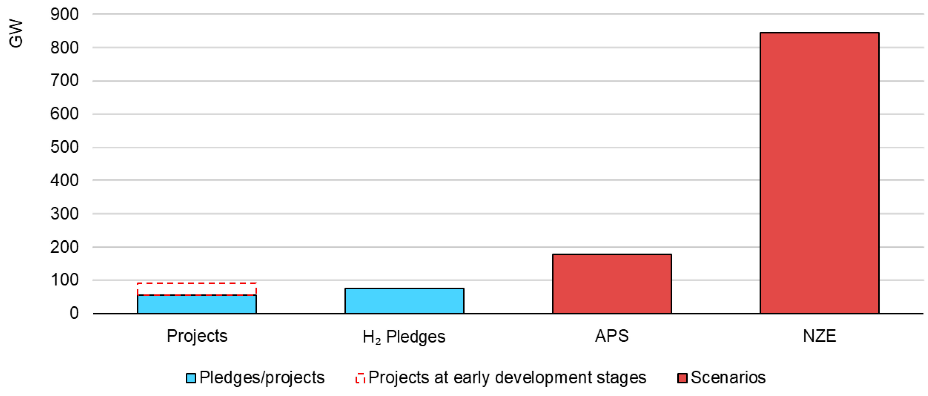
Deployment must accelerate further to meet climate targets

Several countries, as well as the European Union, include electrolyser capacity deployment goals in their hydrogen strategies. Together, these pledges could result in installed capacity of 75 GW by 2030, with the majority linked to the targets of the European Union (40 GW) and Chile (25 GW). However, planned projects do not necessarily match national or regional targets. In the EU case, only 22 GW are currently under construction or planned – barely half of the targeted 40 GW by 2030.

In the Announced Pledges Scenario, global installed electrolyser capacity increases to 180 GW by 2030, twice as much as national targets and three times the projects under construction and planned, and still 70% higher when including in the Projects case also projects at earlier development stages.

In the Net zero Emissions Scenario, capacity requirements in 2030 are 850 GW, some nine times the project pipeline when including projects at early development stages. Despite such significant gaps, current efforts are a good basis from which to expand and accelerate deployment, raising ambition as new projects are developed and more countries build hydrogen into their national strategies.

Electrolysis capacity in the Announced Pledges and Net zero Emissions scenarios in 2030 compared with the current project pipeline and government deployment pledges



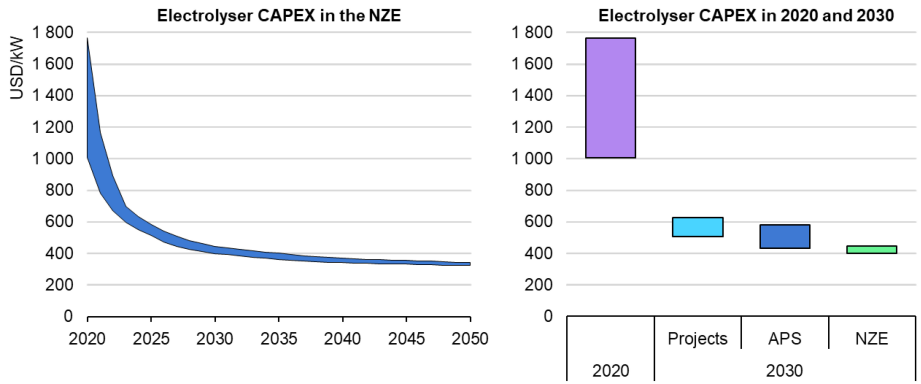
Greater electrolyser deployment will speed cost declines

Projections for hydrogen costs reflect the IEA cost database, recently updated with input from a range of industry participants under the Hydrogen Council and through collaborations with researchers in China. In 2020, costs fell within the range of USD 1 000-1 750/kW (including electric equipment, gas treatment, plant balancing, and engineering, procurement and construction [EPC]), with the lower cost applying to alkaline electrolysers produced in China and the upper representing PEM electrolysers.

The cost of alkaline electrolysers in China – USD 750-1 300/kW, with some sources reporting as low as USD 500/kW[30] – falls well below the average of USD 1 400/kW in the rest of the world. Although concerns over the reliability and durability of Chinese electrolysers have been raised in the past, manufacturing is improving quickly. As recently as a few years ago, Chinese manufacturers had to import several components, limiting their ability to reduce costs through industrial clustering and economies of scale. Local component manufacturing is expanding, however, so cost savings should be realised soon.

Learning effects in manufacturing and economies of scale will also drive down electrolyser costs. A component-wise learning-curve approach was used to analyse future electrolyser costs as a function of cumulative capacity deployment. Based on a literature review, a learning rate of 15% is assumed for the electrolyser stack, which also takes account of learning rates for fuel cells that rely on the same electrochemical processes.

Evolution of electrolyser capital costs under the Projects case, Announced Pledges and Net zero Emissions scenarios



Notes: APS = Announced Pledges Scenario. NZE = Net Zero Emissions Scenario.
Sources: Based on data from McKinsey & Company and the Hydrogen Council.

[30] Based on CAPEX for the electrolyser system itself of USD 200/kW (China EV100, 2020; MOST, 2021). Including inverter and EPC the overall CAPEX increases to USD 500/kW.

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The cumulative capacity deployment of projects under construction and planned would reduce capital expenses by almost 60% by 2030. With capacity deployment in the Announced Pledges Scenario being almost triple the current project pipeline, costs may be 65% lower in 2030 than in 2020. This is not very different from the Net zero Emissions Scenario, for which larger capacity deployment could bring capital expenses down almost 70% from 2020, to USD 400-440/kW.

Shortfalls in electrolysis manufacturing capacity could impede deployment of all projects currently under development, which could derail long-term government climate ambitions (those reflected in the Announced Pledges Scenario) and the Net zero Emissions Scenario. Global electrolysis manufacturing capacity was ~3 GW/yr in 2020, with alkaline designs accounting for 85% and PEMs for less than 15%, plus some very small, artisanal manufacturing of SOECs and AEMs.

The largest shares of manufacturing capacity are in Europe (60%) and China (35%). Interest in the technology is growing among major companies such as Thyssenkrupp, Nel Hydrogen, ITM, McPhy, Cummins and John Cockerill, all of which have announced plans to expand their manufacturing capacities. If all announced expansions are realised, manufacturing capacity could reach ~20 GW/yr, with process automation or improved procurement driving down manufacturing costs.

A dedicated industrialised supply chain and a corresponding industrial supplier landscape will be essential to meet capacity demands to 2030 and beyond. If available soon, this manufacturing capacity could meet the deployment needs of the current pipeline of projects and government pledges (an average of 6-8 GW/y from 2022 to 2030) and approach Announced Pledges Scenario needs (20 GW/yr). But projections still show a shortfall in meeting Net zero Emissions requirements (>90 GW/yr).

Increased electrolyser production will affect demand for minerals, particularly nickel and platinum group metals (depending on the technology type). While alkaline electrolysis does not require precious metals, current designs use 800-1 000 t/MW of nickel. Even if alkaline electrolysis dominates the market by 2030, in the Net zero Emissions Scenario this would entail nickel demand of 72 Mt (which is actually much lower than the amount needed for batteries).

The catalysts in PEM electrolysers require 300 kg of platinum and 700 kg of iridium per GW. Therefore, if PEMs supplied all electrolyser production in 2030 in the Net zero Emissions Scenario, demand for iridium would skyrocket to 63 kt, nine times current global production. Experts believe, however, that demand for both iridium and platinum can be reduced by a factor of ten in the coming decade. Recycling PEM electrolyser cells can further reduce primary demand for these metals and should be a core element of cell design.

Meanwhile, SOEC production requires nickel (150-200 t/GW), zirconium (40 t/GW), lanthanum (20 t/GW) and yttrium (<5 t/GW). Better design in the next decade is expected to halve each of these quantities, with technical potential to drop nickel content to below 10 t/GW. Due to the higher electrical efficiency of SOECs, these mineral requirements are not directly comparable with alkaline and PEM electrolysers.

Low-cost electricity can boost electrolysed hydrogen production

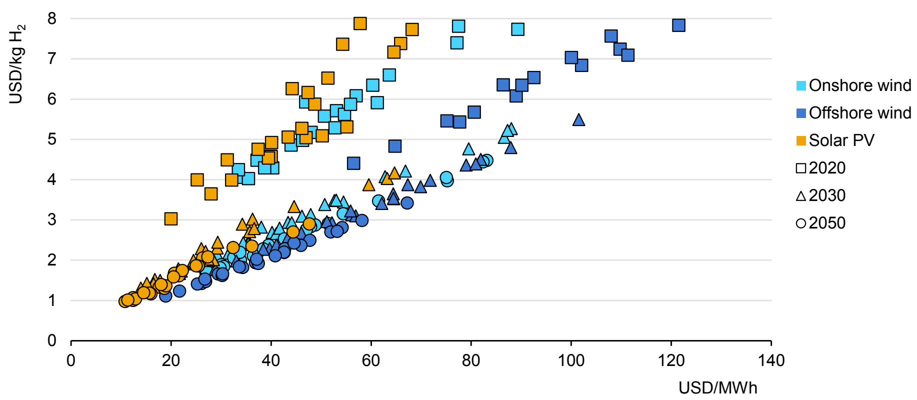
Of the various technical and economic factors that determine how much it costs to produce hydrogen from water electrolysis, the most pertinent are electricity costs, capital expenses, conversion efficiency and annual operating hours.

Electricity costs are the most important consideration, as they account for 50-90% of the overall levelised cost of hydrogen production. Using grid electricity is often rather expensive, with electricity prices of USD 50-100/MWh resulting in hydrogen production costs of USD 3.00-5.00/kg H_2 (at an electrolyser capacity factor of 90% and CAPEX of USD 500/kW).

With shares of variable renewables increasing, surplus grid electricity may be available at low cost to produce hydrogen and to store it for later use. Unfortunately, even if surplus electricity were available at zero cost for 750 hrs/yr, the hydrogen cost would remain at USD 3.00/kg H_2 (CAPEX of USD 500/kW). Running an electrolyser solely on surplus grid electricity therefore may not be an economical way to produce hydrogen and may fail to provide the volumes needed for some demand cases.

However, co-locating hydrogen production with dedicated electricity generation from renewables or nuclear power often avoids or minimises electricity transmission costs. Renewable electricity is thus the dominant source for hydrogen projects currently under construction or being planned.

Hydrogen production costs in the Net zero Emissions Scenario as a function of renewable electricity costs for solar PV and onshore and offshore wind, 2020, 2030 and 2050



Notes: Points represent electricity and hydrogen production costs for different regions around the world, taking local renewable resource conditions into account.
Sources: Based on data from McKinsey & Company and the Hydrogen Council; IRENA (2020).

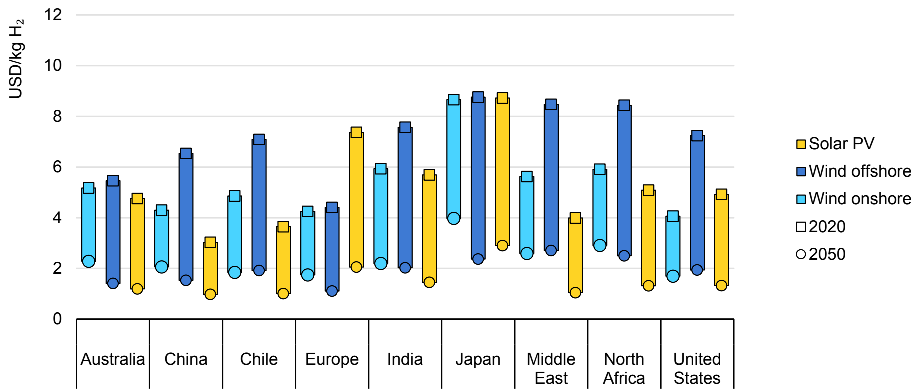
Solar PV has become one of the most affordable energy sources for electricity generation. In locations with excellent solar conditions (i.e. relatively high capacity factors such as the Middle East), solar PV generation costs can be USD 20/MWh or lower, corresponding to hydrogen production costs of USD 3.00/kg H_2 (at an electrolyser capacity factor of 32% and CAPEX of USD 1 000/kW).

With solar PV and electrolyser costs declining in the Net zero Emissions Scenario, hydrogen produced from solar PV in the Middle East at USD 17/MWh could cost less than USD 1.50/kg H_2 in 2030 (at a CAPEX of USD 320/kW), a level comparable to production from natural gas with CCUS. By 2050, with a solar PV cost of USD 12/MWh, hydrogen costs could fall to USD 1.00/kg H_2 (CAPEX of USD 250/kW), making hydrogen from solar PV cost-competitive with natural gas even without CCUS.

Several projects in Europe target offshore wind as an electricity source for hydrogen production. In fact, producing hydrogen offshore and transporting it to shore by pipeline is an alternative to the rather expensive use of electricity cables. Several current and planned pilot and demonstration projects (e.g. the Oyster project in Denmark) are therefore exploring this approach, and the Dutch NorthH2 project aims to reach 4 GW of offshore electrolysis by 2030 while Germany's AquaVentus targets 10 GW by 2035.

Opportunities exist to further reduce costs by repurposing oil and gas assets, for instance by using platforms for electrolyser installations or oil and gas pipelines for hydrogen transport. There are still some uncertainties, however, about the suitability of using certain oil and gas assets for these purposes and the challenges of simultaneously phasing out oil and gas activities while ramping up electrolysis.

Levelised cost of hydrogen production from renewables by technology and region in the Net zero Emissions Scenario, 2020 and 2050



Notes: Higher values of the ranges correspond to 2020, lower values to 2050.
Sources: Based on data from McKinsey & Company and the Hydrogen Council; IRENA (2020).

At USD 60/MWh, electricity generation from offshore wind was relatively costly in 2020, resulting in hydrogen costs of USD 4.50/kg H_2 (at a 50% capacity factor). With declining costs for offshore electricity generation (USD 30/MWh) and larger turbines resulting in higher capacity factors (57%), hydrogen production costs in the North Sea in the Net zero Emissions Scenario could fall to USD 2.00/kg H_2 by 2030 and to below USD 1.50/kg H_2 by 2050 (based on electricity costing USD 25/MWh and a capacity factor of 60%).

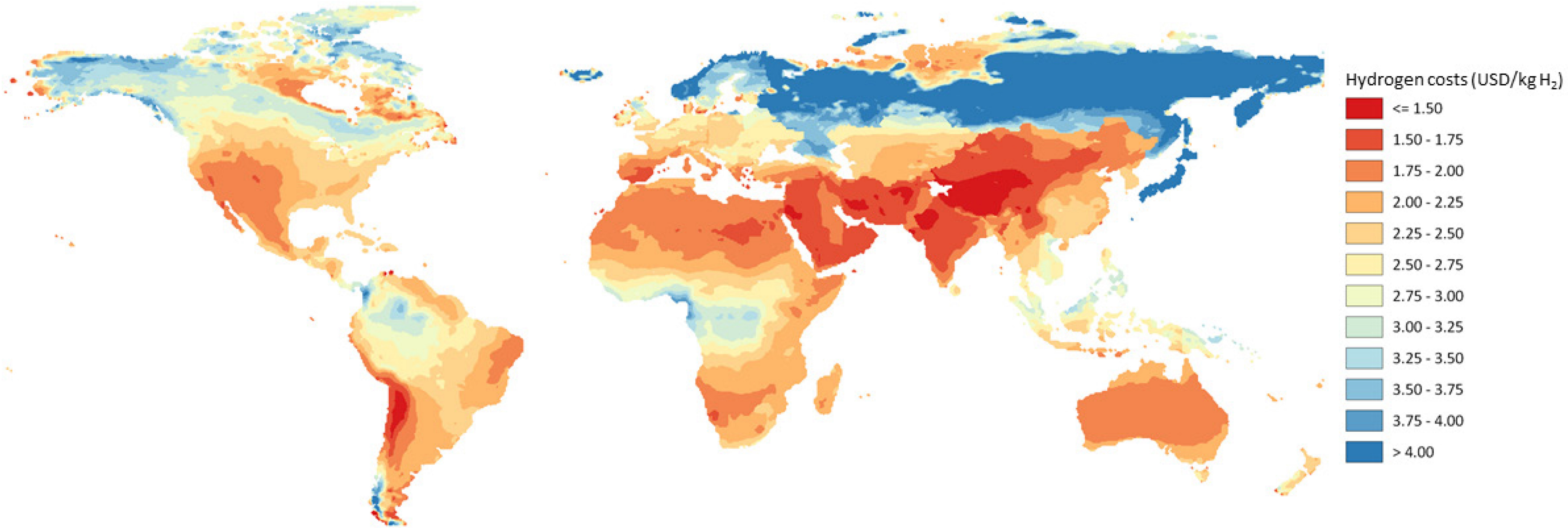
While production costs using offshore wind in Europe remain higher than for solar PV in the Middle East or North Africa, accounting for hydrogen transport costs could make sourcing domestic supplies from offshore wind a more economically feasible option for some parts of Europe.

However, considering solely the levelised cost ignores three other important factors: the number of hours the electrolyser operates; the volume of hydrogen produced throughout the year; and costs that may arise from needing to smooth out renewable hydrogen supply fluctuations (daily or seasonal). While electrolysers can operate quite flexibly to accommodate the variability of renewable electricity supplies, downstream hydrogen users (whether consuming it directly or converting it into other fuels and feedstocks) generally require supply stability. In such cases, hydrogen storage is likely needed to ensure supply constancy.

For the production of hydrogen-based fuels, however, it may be more economical – despite higher hydrogen production costs and fewer full-load hours – to choose a renewable electricity supply with variability patterns that requires less storage, e.g. solar PV (which typically requires daily storage) over wind power (which often requires capacity for several days or weeks of storage). Combining renewable resources in a hybrid plant (e.g. solar PV and onshore wind) may be a cost-effective way to stabilise the hydrogen supply and achieve higher full-load hours, minimising the volume of hydrogen storage needed.

Hydrogen from electrolysis starts to compete with hydrogen from natural gas with CCUS by 2030

Hydrogen production cost from hybrid solar PV and wind systems in 2030



Notes: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. For each location, production were derived by optimising the mix of solar PV, onshore wind and electrolyser capacities, resulting in the lowest costs and including the option to curtail electricity generation.

Sources: Based on hourly wind data from Copernicus Climate Change Service and hourly solar data from Renewables.ninja.

Fossil fuels with carbon capture

Hydrogen production from fossil fuels, and current CCUS status and adoption

Hydrogen produced from natural gas using reforming processes and from coal using gasification are well-established technologies. As noted earlier, these methods dominate hydrogen production and are the sector's primary source of CO_2 emissions.

CCUS is important in the production of low-carbon hydrogen from fossil fuels for two reasons. First, it can reduce emissions from existing hydrogen plants in the refining and chemical sectors, which account for 2.5% of global emissions; and second, it is a low-cost option to scale up production for new hydrogen demand in countries where the conditions are conducive.

CCUS refers to a suite of diverse technologies expected to be important in helping countries meet their energy and climate goals. In its first stage, CCUS involves the capture of CO_2 from large point sources (including power generation or industrial facilities that use fossil fuels or biomass for fuel) or directly from the atmosphere.

Many opportunities exist to use CO_2 captured through CCUS technologies. Urea synthesis with CO_2 captured at ammonia plants (>130 $MtCO_2$/yr in 2020) is currently the only large-scale application, but its anticipated future uses include cement and synthetic fuel production.

Storage refers the practice of injecting captured CO_2 into deep geological formations (typically depleted oil and gas reservoirs or saline formations) where it will be permanently absorbed into the rock. If not being used at the capture site, CO_2 can be compressed and transported to other facilities by pipeline, ship, rail or truck – for either use or storage.

Current large-scale CO_2 capture capacity for injection into geological formations (for dedicated storage and use in enhanced oil recovery) is in the order of 40 $MtCO_2$/yr. Around two-thirds of this capacity is in natural gas processing facilities, with the remainder distributed in roughly equal shares in power generation, synthetic fuel, ammonia and hydrogen applications, with smaller quantities captured from bioethanol and steel production.

In natural gas-based hydrogen production, steam methane reforming (SMR), the leading production route, creates direct CO_2 emissions of 9 kg CO_2/kg H_2 while upstream methane emissions from natural gas production and transport can add another 1.9-5.2 kg CO2eq/kg H2 (global average of 2.7 kg CO2eq/kg H2), reflecting regional variations. Efforts need to be taken to address them. Technologies to reduce upstream methane emissions are already available and are often cost-effective without additional support.

Among direct emissions of the SMR process, 30-40% arise from using natural gas as the fuel to produce steam and heat, giving rise to a "diluted" CO_2 stream. The rest of the natural gas used in this process is split (with the help of the steam) into hydrogen and more concentrated "process" CO_2. While capturing CO_2 from the concentrated process stream can reduce overall emissions by 60%, capturing the more diluted gas stream can boost overall emissions reductions to 90% or higher. The cost of capturing both combined is USD 50-70/t CO_2.

Autothermal reforming (ATR) is an alternative technology in which the process itself produces the required heat. This means that all related CO_2 is produced inside the reactor, resulting in a more concentrated flue gas stream that, when compared with the SMR process, allows for higher CO_2 capture rates (95% or higher) or for the same capture rate at lower capture costs.

ATR uses oxygen instead of steam, which requires electricity (rather than methane) as its fuel input. A large share of global ammonia and methanol production already uses ATR technology, though without CCUS. Two projects in the United Kingdom – HyNet and H2H Saltend – plan to combine ATR with CCUS.

Partial oxidation (POx) is a technology option that supports hydrogen production from gaseous or liquid fuels. The process does not require a catalyst (unlike ATR) and can accept feedstock impurities. POx uses oxygen (similar to ATR), requiring electricity as the energy input. Traditionally, the process has been deployed where it is possible to use low-value waste products or heavy feedstocks to produce hydrogen or syngas (e.g. in refineries).

The technology is available at commercial scale but has been modified only recently with the express aim of producing hydrogen from natural gas with CCUS. Several projects based on POx are under development and show CO_2 capture rates of up to 100%. A POx hydrogen plant at a Dutch refinery (using oil residues) that has been operating since 1997 began capturing CO_2 in 2005 for use in greenhouses (at a rate of 0.4 MtCO_2/yr, not fully utilising the installed capture capacity of 1 Mt CO_2/yr, which may be exploited by the Porthos project).

Meanwhile, coal gasification is a mature technology used mainly in the chemical industry to produce ammonia, particularly in China. At 20 t CO_2/t H_2, unabated hydrogen production from coal is very emissions-intensive. Though some technical challenges remain to be overcome, coal gasification can be combined with CCUS. However, since gas separation technologies focus on either hydrogen or CO_2 removal, few can produce both high-purity hydrogen and CO_2 pure enough for other uses or storage.

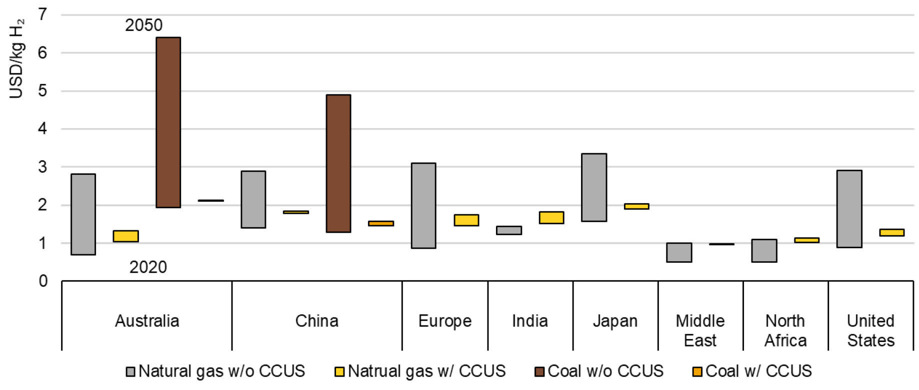
The choice and design of capture technology therefore depends on the hydrogen end-use and production costs. With the aim of producing hydrogen for export to Japan, the planned Hydrogen Energy Supply Chain project (Australia) seeks to produce it from brown coal using gasification, with CO_2 being transported and stored via the CarbonNet project.

Sixteen projects are currently generating hydrogen from fossil fuels with CCUS; with annual combined production of just over 0.7 Mt H_2, they also capture close to 10 Mt CO_2. Ten are commercial-scale plants with CO_2 capture capacity above 0.4 Mt CO_2/yr: four are at oil refineries and three are at fertiliser plants.[31] Notably, six are retrofits of existing sites, with scales ranging from <100 MW_{H2} to >1 GW_{H2}, with 1 GW_{H2} corresponding to annual production of 0.25 Mt H_2. Planned projects reach a capacity of up to 20 GW_{H2}.

In regions with low-cost domestic coal and natural gas, where CO_2 storage is available – e.g. the Middle East, North Africa, Russia and the United States – the use of fossil fuels with CCUS is currently the most affordable option to produce low-carbon hydrogen and ammonia. Depending on local gas prices, costs for producing hydrogen from natural gas with CCUS were in the range of USD 1.00-2.00/kg H_2 in 2020 – about USD 0.50/kg H_2 higher than for natural gas without CCUS, due to CO_2 capture, transport and storage costs. As the CO_2 price penalty on uncaptured CO_2 emissions (5-10%) rises over time, production costs from fossil fuels with CCUS will increase slightly.

[31] These include facilities that produce pure hydrogen and capture CO_2 for geological storage or sale. CO_2 captured from ammonia plants for use in urea manufacturing is excluded.

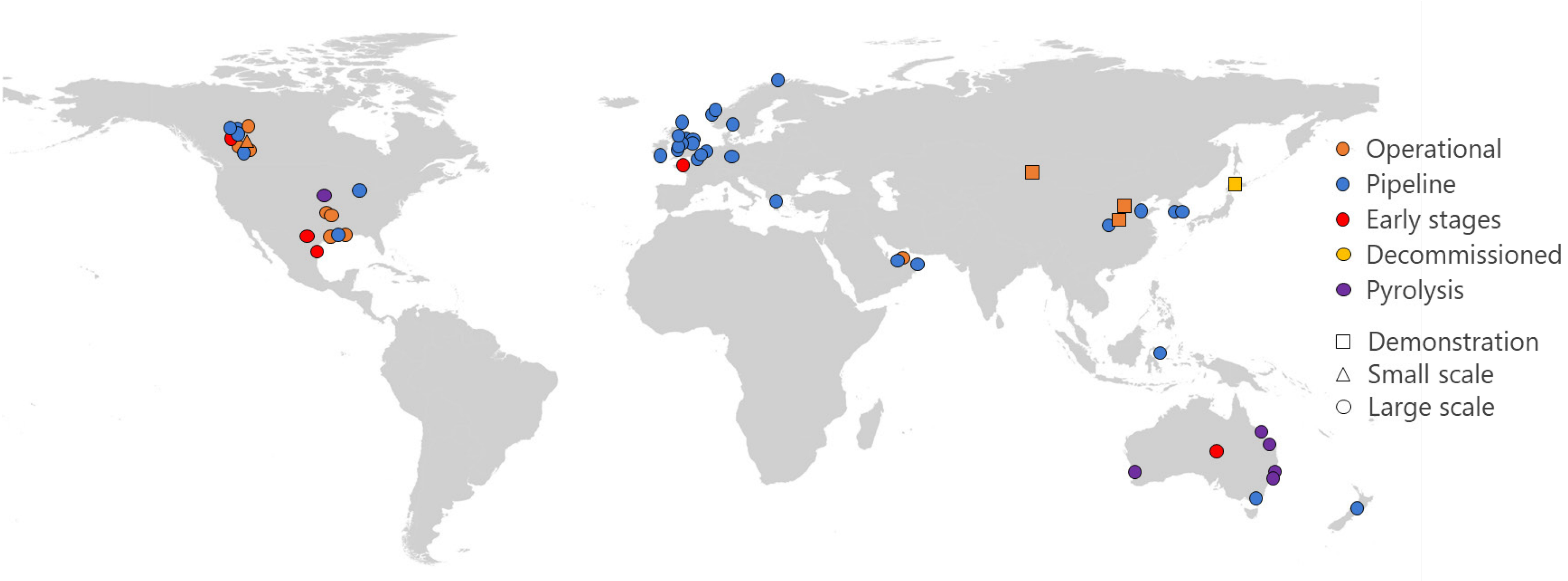
Levelised hydrogen production costs from natural gas and coal by region in 2020 and in the Net zero Emissions Scenario in 2050



Notes: The lower values of the ranges correspond to 2020, higher values to 2050.
Sources: Based on data from McKinsey & Company and the Hydrogen Council; IEA GHG (2014); IEA GHG (2017); E4Tech (2015); Kawasaki Heavy Industries; and Element Energy (2018).

Hydrogen production from fossil fuels with CCUS is gaining momentum

Projects for producing hydrogen from fossil fuels with CCUS, operational or under development



Notes: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. Mature projects are projects under construction or for which a final investment decision has been taken.

Source: IEA (2021), Hydrogen Projects Database.

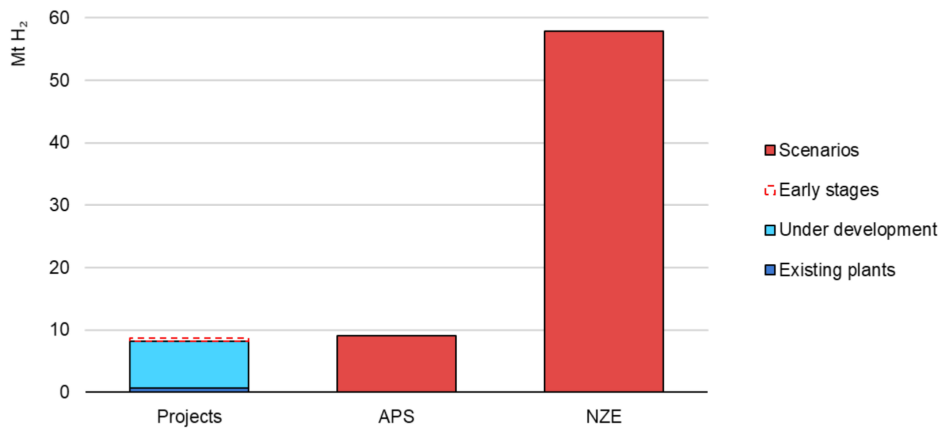
Outlook for hydrogen production with CCUS

Globally, 40 projects for producing hydrogen with CCUS are under development, with a total of four currently under construction in China and the United States. Of these, 35 rely on natural gas with CCUS, four are linked to coal and one to oil. Geographically, Europe hosts 19 projects (largely in the Netherlands and the United Kingdom), while North America hosts 7 and China has 2.

Based on planned projects and existing plants, global hydrogen production from fossil fuels with CCUS could reach 9 Mt by 2030. While several national strategies and roadmaps consider this a low-carbon hydrogen production option, almost none define deployment targets for hydrogen with CCUS, in contrast to electrolysis. Exceptions are the United Kingdom, with a technology-neutral target of domestic low-carbon production capacity of 5 GW_{H2} by 2030, and the low-carbon supply targets of Japan (420 kt H_2) and the Czech Republic (10 kt H_2). Assuming these targets were fulfilled solely by hydrogen production with CCUS, it would correspond to 1.7 Mt H_2 annually.

Estimated production of 9 Mt H_2 in 2030 from planned and existing plants aligns with the Announced Pledges Scenario. The jump to 58 Mt H_2 from fossil fuels with CCUS in the Net zero Emissions Scenario is around seven times the project pipeline, implying that – by 2030 – some 230 hydrogen plants with capacity of 1 GW_{H2} need to be newly built or retrofitted with CCUS. While this number may seem huge, it corresponds to roughly 80% of current unabated production capacity from fossil fuels.

Hydrogen production from fossil fuels with CCUS in the Announced Pledges and Net zero Emissions scenarios, compared with the project pipeline and government pledges, 2030



Source: IEA (2021), Hydrogen Projects Database.

Industrial ports – where a large share of unabated fossil hydrogen production plants for refining and the petrochemical industry is located – could become hubs for scaling up hydrogen production. In addition to offering offshore storage potential, they could share CO_2 transport and storage infrastructure across different industries, benefitting from economies of scale that could reduce investment risks. Active examples are the Port of Rotterdam (Porthos) project inthe Netherlands, the Zero Carbon Humber project in the United Kingdom, and CarbonNet in Australia.

Growing momentum for CCUS

Interest in CCUS is expanding globally, as strengthened climate commitments – including ambitious net zero targets – from governments and industry drive renewed momentum. In the first eight months of 2021, more than 40 new commercial projects were announced, reflecting an improved investment environment. A variety of CCUS projects are operating or in planning across several sectors:

- **Industry:** CO_2 capture is already an integral part of urea manufacturing and other industrial processes. Deployment is expanding to chemical products, the steel sector (with one commercial plant operating) and the cement sector (construction to retrofit a plant in Norway has commenced).
- **Electricity and heat:** Two coal-fired power plants equipped with CCUS (in Canada and the United States) have a capture capacity of 2.4 Mt CO_2/yr. Globally, plans exist to equip around 30 coal, gas, biomass or hydrogen power facilities with CCUS.
- **Fuel supply:** Most existing commercial CCUS facilities are linked to natural gas processing, which has relatively low capture costs; collectively, they currently capture almost 30 Mt CO_2/yr. A wide range of CCUS projects are planned, associated with production of low-carbon hydrogen and biofuels, refining, and LNG; several are linked to development of regional CCUS and/or hydrogen hubs.
- **Direct air capture:** A number of small pilot and demonstration DAC plants are currently operating around the world, including some in commercial operation to provide CO_2 for beverage carbonation and greenhouses, and a large-scale (1 Mt/yr) facility is in development in the United States.

CCUS technologies and applications are at various stages of development. Several capture technologies, such as chemical absorption of CO_2 during hydrogen production in ammonia plants, are mature and have high (85-90%) average capture rates (e.g. of CO_2 in the gas stream). Boosting capture rates to 99%, which would substantially decrease residual emissions from CCUS operations, is technically possible with minimal additional cost, but requires incentives such as sufficiently high CO_2 prices or low-carbon standards.

As urea applied on soils breaks back down into ammonia and CO_2 and synthetic fuels are combusted to extract embedded energy, it must be noted that CO_2 used for urea production or for synthetic fuels will eventually be released into the atmosphere. For hydrogen to be considered low-carbon, CO_2 captured during production would need to be permanently stored (rather than used).

A well-selected and well-managed geological storage site can retain stored CO_2 for more than 1 000 years, with minimal risk of leakage. Theoretically, global CO_2 storage resources are vast; however, some reservoirs will not be suitable or accessible. In many regions, detailed site characterisation is still needed to assess the feasibility and scope of permanent CO_2 storage. At present, a relatively low share of captured CO_2 – only 20% the 40 Mt quoted above – is directed into permanent geological storage (80% is used for EOR).

Hydrogen-based fuels

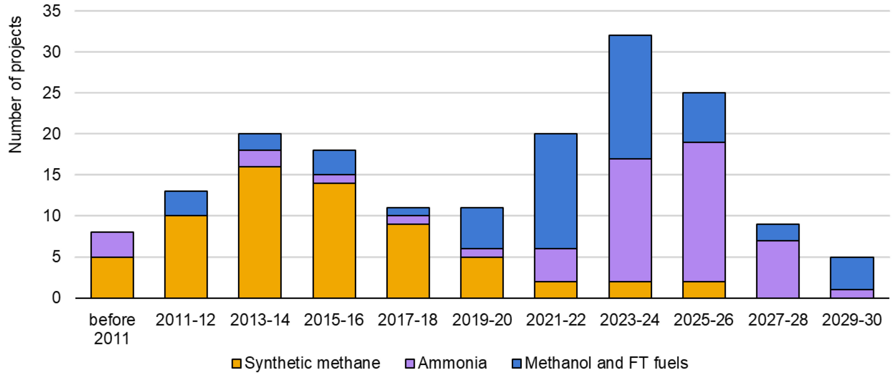
Hydrogen-based fuels are often compatible with existing infrastructure, but cost more

Hydrogen produced through the methods described above has a low volumetric energy density, which makes it more challenging to store and transport than fossil fuels. It can, however, be converted into hydrogen-based fuels and feedstocks (e.g. synthetic methane, synthetic liquid fuels and ammonia) that can be transported, stored and distributed through existing infrastructure for fossil fuels. In fact, some synthetic hydrocarbons from hydrogen can directly substitute for fossil equivalents. The potential benefits and opportunities of these fuels and feedstocks must be weighed against additional conversion losses and related costs.

In 2020, 81 pilot or demonstration projects were in operation, converting electrolytic hydrogen into synthetic methane (59), synthetic methanol (7), synthetic diesel or kerosene (7) and ammonia (8).. Geographically, most are in Europe, and most are at a relatively small scale to demonstrate technologies and supply chains.

Besides hydrogen, synthetic hydrocarbon fuel production requires CO_2 as an input. Initially, the CO_2 may be sourced from hard-to-abate emissions sources. But to ensure the CO_2 neutrality of the produced fuel in the long term, CO_2 supplies should be captured at bioenergy conversion plants or directly from the atmosphere. The Power2Met project (Denmark) uses CO_2 from biogas upgrading, while the Troia plant (Italy) uses DAC for CO_2 to produce synthetic methane.

New projects to produce hydrogen-based fuels from electrolytic hydrogen, by start year



Notes: FT = Fischer-Tropsch. Figure includes eight synthetic methane and five FT fuel projects decommissioned before 2020. Ammonia includes projects in the chemical industry, where ammonia is used as a feedstock.
Source: IEA (2021), Hydrogen Projects Database.

Several projects planned for upcoming years are expected to advance to the commercial scale. With an electrolyser capacity of 2 GW, the Haru Oni project for methanol (Chile) has a planned final production capacity of 550 million litres per year (by 2026). The Helios Green Fuels project (Saudi Arabia), based on electrolyser capacity of 1.5-2.0 GW, has a planned annual production capacity of 235 kt hydrogen and 1.2 Mt ammonia.

In parallel, the focus of projects under construction or planned shifts from synthetic methane to synthetic liquid fuels (ammonia, methanol and Fischer-Tropsch fuels), with the last accounting for >90% of future projects. This may reflect that using hydrogen-based liquid fuels is an important pathway to decarbonise long-distance transport, particularly aviation and shipping. In the Net zero Emissions Scenario in 2050, ammonia covers 45% of global shipping fuel demand while synthetic kerosene accounts for one-third of global aviation fuel consumption.

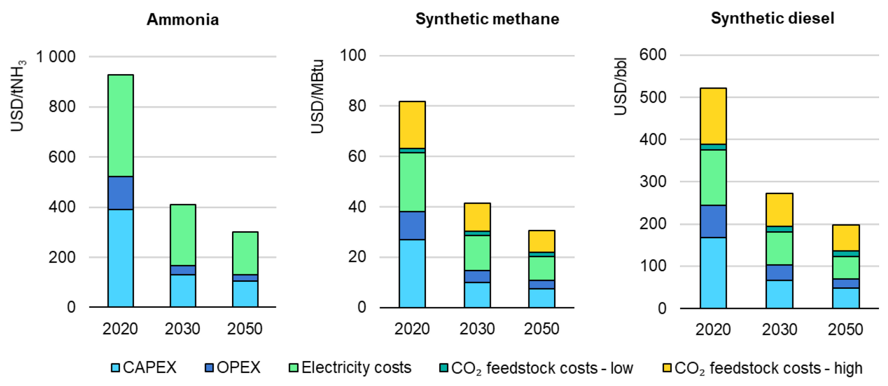
The economics of producing clean ammonia and synthetic hydrocarbon fuels depend on various factors, the cost of hydrogen being key. Fossil fuel and CO_2 storage prices will affect the cost of producing hydrogen using CCUS, whereas for the electrolytic hydrogen route, the availability of low-cost and low-carbon electricity is critical.

In the case of synthetic hydrocarbon fuels, the availability and cost of CO_2 feedstocks is another important factor. CO_2 costs currently range from USD 30/t CO_2 from ethanol plants to USD 150-450/t CO_2 from DAC (but as DAC technology is at an early stage of development, costs could fall to USD 70-240/t CO_2 by 2050). With CO_2 feedstock costs at USD 30-150/t CO_2, production costs for synthetic liquid fuels fall in the range of USD 15-75/bbl.

Current production costs for synthetic liquid hydrocarbon fuels from electrolytic hydrogen are in the range of USD 300-700/bbl. With cost declines for renewable electricity, electrolysers and DAC, they fall to USD 120-330/bbl by 2050 in the Net zero Emissions Scenario, which is still much more expensive than conventional fossil liquid fuels. The situation for synthetic methane is similar.

To support use of these fuels in parts of the energy system with limited low-carbon options (e.g. long-distance transport in aviation or shipping), policy measures are needed to close the cost gap by either pushing up the cost of using of fossil fuels (e.g. CO_2 prices) or incentivising low-carbon fuel use (e.g. clean fuel standards). To close the cost gap with fossil kerosene at USD 25/bbl, a CO_2 price of USD 230-750/t CO_2 would be needed to deliver synthetic liquid hydrocarbon fuels at USD 120-330/bbl.

Levelised cost of ammonia, synthetic methane and synthetic liquid fuels for electricity-based pathways in the Net zero Emissions Scenario, 2020, 2030 and 2050



Sources: Based on data from McKinsey & Company and the Hydrogen Council; IRENA (2020); Agora (2018); Danish Energy Agency (2021); IFA (2021).

Emerging technologies

Hydrogen production technologies of the future hold promise

Solid oxide electrolyser cells (SOECs)

SOECs use steam instead of water for hydrogen production, a key departure from alkaline and PEM electrolysers. Additionally, as they use ceramics as the electrolyte, SOECs have low material costs. While they operate at high temperatures and with high electrical efficiencies of 79-84% (LHV), they require a heat source to produce steam. Therefore, if SOEC hydrogen were used to produce synthetic hydrocarbons (power-to-liquid [PtL] and power-to-gas [PtG]), it would be possible to recover waste heat from these synthesis processes (e.g. Fischer-Tropsch synthesis, methanation) to produce steam for further SOEC electrolysis. Nuclear power, solar thermal and geothermal heat systems, as well as industrial waste heat, could also be heat sources for SOECs.

SOEC electrolysers can also be operated in reverse mode as fuel cells to convert hydrogen back into electricity, another feature that is distinct from alkaline and PEM electrolysers. Combined with hydrogen storage facilities, they could provide balancing services to the power grid, increasing the overall utilisation rate of equipment. SOEC electrolysers can also be used for co-electrolysis of steam and CO_2, thereby creating a syngas mixture (carbon monoxide and hydrogen) for subsequent conversion into a synthetic fuel.

SOECs are still in the demonstration phase for large-scale applications (TRL 6-7[32]). Operational systems, often linked to the production of synthetic hydrocarbon fuels, currently have capacities of <1 MW. The largest system in operation (720 kW capacity) uses renewable electricity and waste heat to produce hydrogen for a DRI steel plant. However, a 2.6-MW SOEC system is being developed in Rotterdam, and several companies (e.g. Bloom, Sunfire) are manufacturing SOEC systems, mainly in Europe. Denmark plans to launch a manufacturing plant with an annual capacity of 500 MW by 2023.

Methane pyrolysis

Methane pyrolysis (also known as methane splitting, cracking or decomposition) is the process of converting methane into gaseous hydrogen and solid carbon (e.g. carbon black, graphite), without creating any direct CO_2 emissions. The reaction requires relatively high temperatures (>800°C), which can be achieved through conventional means (e.g. electrical heaters) or using plasma. Per unit

[32] A technology's technology readiness level indicates its current maturity within a defined scale, ranging from the definition of basic principles (TRL 1) to full commercial operation in a relative environment (TRL 9). See https://www.iea.org/articles/etp-clean-energy-technology-guide.

of hydrogen produced, methane pyrolysis uses three to five times less electricity than electrolysis; however, it requires more natural gas than steam methane reforming.

The overall energy conversion efficiency of methane and electricity combined into hydrogen is 40-45%. Notably, the process could create additional revenue streams from the sale of carbon black for use in rubber, tyres, printers and plastics, though the market potential is likely limited, with global demand for carbon in 2020 being 16 Mt of carbon black, which corresponds to hydrogen production from pyrolysis of 5 Mt H_2. Carbon from pyrolysis could be used in other applications such as construction materials or to replace coke in steelmaking.

Several methane pyrolysis technology designs under development show TRLs of 3 to 6. Monolith Materials (in the United States) uses thermal plasma to create the high temperatures required. After operating a pilot plant for four years, the company launched an industrial plant in 2020 (in Nebraska) and is planning a commercial-scale plant for ammonia production. To convert biogas into hydrogen and graphite, Hazer Group (Australia) is building a demonstration plant for its catalytic-assisted fluidised bed reactor technology, and BASF (Germany) is developing an electrically heated moving-bed reactor process. Together with RWE, in 2021 the company announced a project to use electricity from offshore wind to produce hydrogen from electrolysis and for a methane pyrolysis plant. Gazprom (Russia) is developing a plasma-based process for methane pyrolysis. The start-up C-Zero (United States) is working on an electrically heated molten-metal reactor for methane pyrolysis.

Anion exchange membranes (AEMs)

AEM electrolysis combines some of the benefits of alkaline and PEM electrolysis. Using a transition metal catalyst (CeO_2-La_2O), it does not require platinum (unlike PEM electrolysis). A key advantage is that the anion exchange membrane itself serves as solid electrolyte, avoiding the corrosive electrolytes used in AEL. AEM technology is still at an early stage of development (TRL 4-5), but Enapter (Germany) is developing kW-scale AEM electrolyser systems that can be combined to form MW-scale systems.

Electrified steam methane reforming (ESMR)

SMR is a widely used process to produce hydrogen from natural gas, and it can be combined with CCUS to reduce CO_2 emissions. To achieve capture rates of 90% or higher, CO_2 capture needs to be applied to two gas streams: the synthesis gas stream after the steam methane reformer (characterised by relatively high CO_2 concentrations) and a more diluted flue gas stream caused by steam production from natural gas. Because the latter has a lower CO_2 concentration, capture requires more energy.

An alternative to capturing CO_2 from flue gas, which accounts for 40% of CO_2 emissions from natural gas SMR, is to use an alternative heat source to produce the steam. Haldor Topsoe (Denmark) is using low-carbon electricity (hence SMR becomes ESMR) at a level of 8 kWh/kg H_2. The technology has been demonstrated at only the laboratory scale (TRL 4) to date, but a pilot plant is under construction to use biogas as a feedstock in ESMR to produce hydrogen and carbon monoxide, which will then be converted into methanol.

Infrastructure and trade

Infrastructure

Efficient development of hydrogen infrastructure requires analysis at the system level

Large-scale hydrogen deployment will need to be underpinned by an effective and cost-efficient system for storage and transport, strategically designed to connect supply sources to demand centres and thereby establish a deep liquid market. While there is generally consensus on the need to expand the penetration of hydrogen in the energy system to decarbonise certain hard-to-abate sectors, uncertainty remains about how its production, consumption and geographical distribution will evolve.

This uncertainty in turn influences how infrastructure for hydrogen storage and transport is developed. Efficient infrastructure design will depend on several aspects, including demand volumes; the location of infrastructure relative to resources for producing low-carbon hydrogen (renewables and CO_2 storage sites); technologies used for production; and existing natural gas and electricity networks, as well as their future development. In some cases, transporting electricity for decentralised electrolytic hydrogen production may be the most economical choice, but under different circumstances, centralised production relying on hydrogen transport can be preferable.

The final use of hydrogen can also dictate how it is transported. In certain cases, hydrogen could be used locally to produce end products (chemical products, fertiliser or steel) or to produce other fuels (ammonia or synthetic fuels) that could be transported more cost-efficiently. In other cases, pure hydrogen would be the final product (for use in transport or high-temperature heating) and its transport as pure hydrogen (gaseous or liquefied) or using a hydrogen carrier (ammonia or a liquid organic hydrogen carrier [LOHC]) would depend on the total cost of transport (including conversion/reconversion, storage and transport).

Although hydrogen's high versatility makes a wide range of possibilities and solutions available across diverse sectors, inadequate planning could result in the construction of inefficient and costly infrastructure. Thus, integrated analysis at the system level is needed to design efficient infrastructure for producing hydrogen and transporting it to end users.

More pipeline transport is needed to reach hydrogen targets

Hydrogen can be transported either in gaseous form by pipelines and tube trailers or in liquefied form in cryogenic tanks. IEA analysis indicates that pipeline is generally the most cost-efficient option for distances of <1 500-3 000 km, depending on pipeline capacity. For longer distances, alternatives such as transporting liquefied hydrogen, ammonia or LOHCs by ship could be more attractive (see also Hydrogen Trade below).

Transmitting hydrogen by pipeline is a mature technology. The first hydrogen pipeline system was commissioned in the Rhine-Ruhr metropolitan area (Germany) in 1938 and remains operational. Historically, carbon steel or stainless steel have been used for hydrogen-line pipes, as higher grades (>100 ksi) present a higher risk of hydrogen embrittlement. Hydrogen pipelines currently cover more than 5 000 km, with >90% located in Europe and the United States. Most are closed systems owned by large merchant hydrogen producers and are concentrated near industrial consumer centres (such as petroleum refineries and chemical plants).

Similar to natural gas pipeline systems, hydrogen pipelines are capital-intensive projects that have high upfront investment costs. Due to the inflexible and durable nature of these assets, investments become sunk as soon as the pipeline is laid. High initial capital costs and associated investment risks can therefore impede hydrogen pipeline system development significantly, especially when demand is nascent and regulatory frameworks have not been established.

Moreover, because thicker pipeline walls are required at larger diameters, construction costs for new-build hydrogen pipelines are typically higher than for natural gas pipelines. At a similar diameter, the CAPEX of hydrogen-specific steel pipelines is 10-50% higher than for natural gas.

Reaching the targets set in hydrogen strategies will necessitate much faster hydrogen transmission development. IEA analysis shows that by 2030, the total length of hydrogen pipelines globally will need to double to 10 000 km in the Announced Pledges Scenario and quadruple to >20 000 km in the Net zero Emissions Scenario.

Fortunately, existing natural gas infrastructure can act as a catalyst to scale up hydrogen transportation. In the short to medium term, blending hydrogen into natural gas can facilitate the initial development of trade, while repurposing gas pipelines can significantly reduce the cost of establishing national and regional hydrogen networks.

Hydrogen blending can be a transitionary solution

By providing a temporary solution until dedicated hydrogen transport systems are developed, blending hydrogen in gas networks can support initial deployment of low-carbon hydrogen and trigger cost reductions for low-carbon hydrogen production technologies. While several pilot projects have been launched in recent years, blending still faces several technical and regulatory barriers. Parameters related to natural gas quality (composition, calorific value and Wobbe index) – as regulated in different countries – can limit (or completely prevent) injection of hydrogen into gas grids.

The hydrogen purity requirements of certain end users, including industrial clients, can further constrain blending. In addition, resulting changes in the physical characteristics of the gas can affect certain operations, such as metering. To avoid interoperability issues arising from the changing quality of gas, hydrogen blending will require that adjacent gas markets co-operate more closely.

Hydrogen can be injected into gas networks either directly in its pure form or as "premix" with natural gas. Due to its chemical properties, however, it can cause embrittlement of steel pipelines, i.e. reactions between hydrogen and steel can create fissures in pipelines. Depending on the characteristics of the gas transmission system, hydrogen can be blended at rates of 2-10 vol%H_2[33] without substantial retrofitting of the pipeline system. The hydrogen tolerance of polymer-based distribution networks is typically greater, potentially allowing blending of up to 20 vol%H_2 with minimal or possibly no modifications to the grid infrastructure.

The injection of low-carbon hydrogen into gas grids has grown sevenfold since 2013, but volumes remain low. In 2020, ~3.5 kt H_2 were blended, almost all in Europe and mainly in Germany, which accounted for close to 60% of injected volumes. In France, the GRHYD demonstration project is testing injection of up to 20 vol%H_2 into the natural gas distribution grid of Cappelle-la-Grand (near Dunkirk). In Italy, the Snam project demonstrated the feasibility of blending up to 10% hydrogen in its transmission grid, while in the United Kingdom, the HyDeploy demonstration project tested injection of up to 20 vol%H_2 into Keele University's existing natural gas network (the project became fully operational in early 2020).

Interest in blending is growing in other regions as well. In Australia, pipeline network operators are developing demonstration projects allowing 5-10% volH_2 blend injections starting in 2021 or 2022. Australia Gas Infrastructure Group (AGIG) launched the country's

[33] The energy density of hydrogen is about one-third that of natural gas.

first hydrogen blending pilot project (Hyp SA) in May 2021. Under this project, AGIG will blend about 5 vol% green hydrogen into South Australia's gas distribution network, supported by a 1.25-MW electrolyser operating on solar and wind energy.

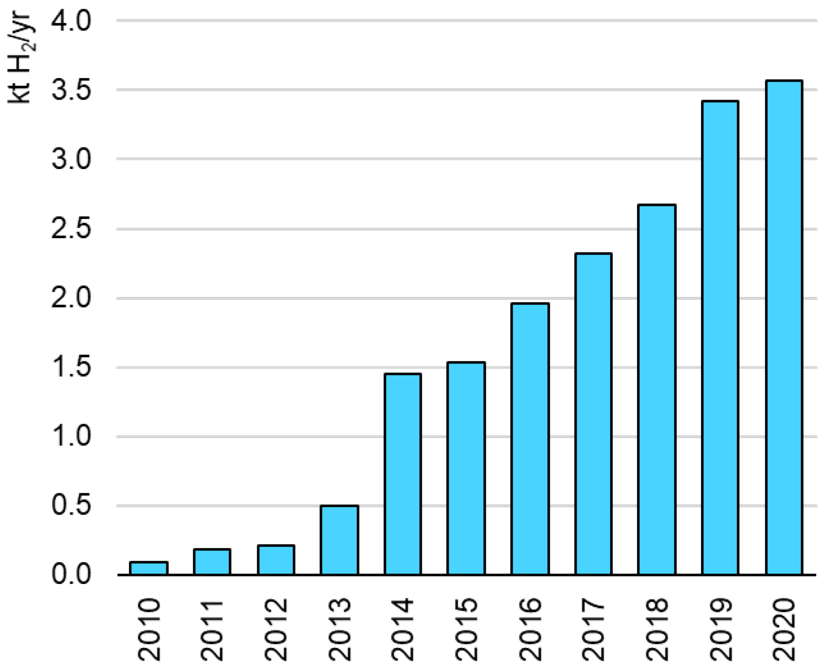
In the United States, a first demonstration project on polymer-based distribution pipelines is expected to be launched in California in 2021, with its initial blend level of 1 vol% potentially rising to 20 vol%H_2. In Canada, a hydrogen demonstration project in Ontario is set to start in 2021, allowing for a maximum hydrogen blended content of up to 2% of the natural gas supplied.

Based on projects that have reached final investment decision (FID) or are under construction, hydrogen blending could increase by a factor of 1.3 by 2030 (>4 kt H_2). However, if all proposed grid-connected hydrogen projects are realised, it could rise by over 700 times to >2 Mt H_2. Still, this falls massively short of the 53 Mt H_2 that need to be blended into gas grids globally in 2030 in the Net zero Emissions Scenario.

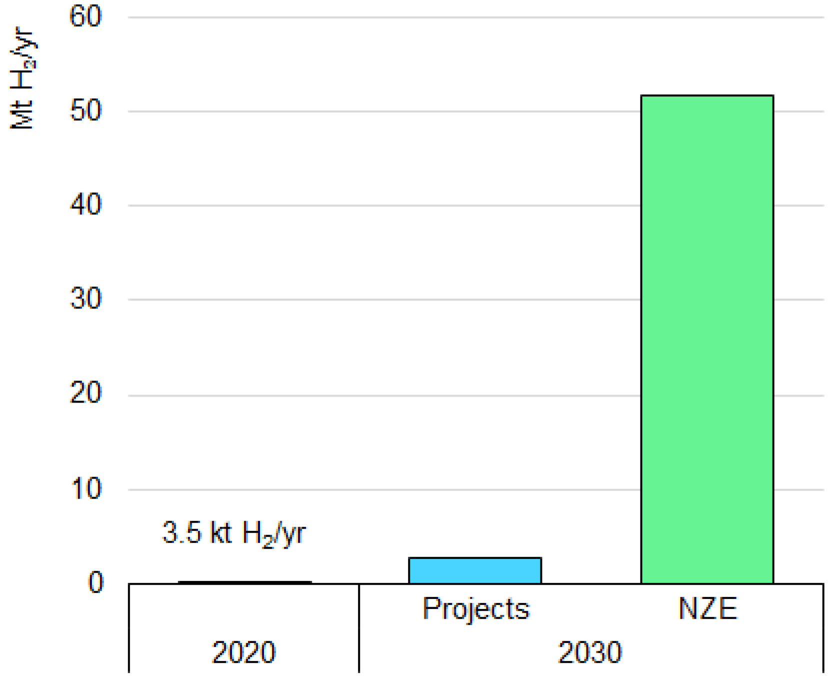
Supportive policies and regulatory mechanisms, including blend certificates and/or guarantees of origin, could spur hydrogen trading and pipeline transport development. While the costs associated with hydrogen blending are relatively low, emissions savings are rather limited, with only a ~10% CO_2 reduction at a blending rate of 30%.

Consequently, in terms of climate change action, blending is a transitionary solution than can help build up stable sources for low-carbon hydrogen demand until a dedicated hydrogen transport system is developed.

Estimated low-carbon hydrogen injected into gas networks, 2010-2020



Low-carbon hydrogen injected into gas networks in the Projects case and Net Zero Emissions Scenario, 2020-2030



Note: NZE = Net zero Emissions Scenario.
Source: IEA (2021), Hydrogen Projects Database.

Old but gold: Repurposing gas infrastructure can catalyse hydrogen network development

Compared with building new hydrogen pipelines, repurposing existing natural gas pipeline systems as dedicated hydrogen networks can be substantially less costly and the lead times can be much shorter. Ultimately, this could translate into lower transport tariffs and improve the cost-competitiveness of hydrogen.

Pipeline repurposing can range from simple measures (e.g. replacing valves, meters and other components) to more complex solutions, including replacing/recoating pipeline segments (which entails pipe excavation). Also, considering that hydrogen has a higher leakage rate and an ignition range about seven times wider than that of methane, it may be necessary to upgrade leak detection and flow control systems.

Based on technical analysis of Germany's gas transmission system, Siemens estimates that compressor stations can generally be used without major changes up to 10 vol%H_2; beyond 40 vol%H_2, they have to be replaced, driving up initial investment costs. Notably, the compressor power required per unit of hydrogen transportation is about three times higher than for natural gas, resulting in higher operating expenses. The amount of total compressor power required will ultimately depend on market demand for hydrogen.

Practical experience of gas-to-hydrogen pipeline conversion is rather limited, with several crude oil and product pipelines repurposed to carry hydrogen in the 1970s and 1990s. The first conversion of a natural gas pipeline for full hydrogen service in the Netherlands was put into commercial service in November 2018 by Gasunie (12 km with throughput capacity of 4 kt H_2/yr). Repurposing took six to seven months.

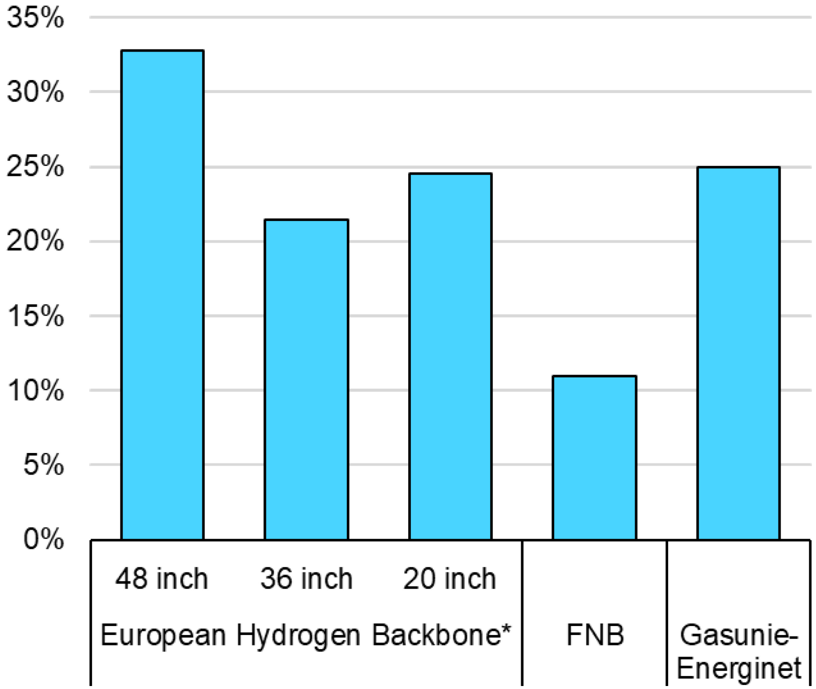
In Germany, as part of its H2HoWi R&D project, E.ON announced the conversion of a natural gas pipeline with an investment cost of EUR 1 million (works started at the end of 2020). In addition, GRTgaz and Creos Deutschland launched the MosaHYc project to convert two existing natural gas pipelines into a 70-km pure hydrogen infrastructure along the border where Germany, France and Luxembourg intersect (FID expected by 2022). In Australia, APA announced the repurposing of 43 km of its Parmelia pipeline in Western Australia as a demonstration project, with testing to be completed by the end of 2022.

The cost benefits of gas pipeline repurposing can be substantial. The European Hydrogen Backbone (EHB) study suggests conversion costs are 21-33% the cost of a new hydrogen pipeline. Of an expected ~40 000 km of hydrogen pipelines in Europe by 2040, the study estimates 75% will be repurposed. The latest draft network development plan of Germany's Transmission System Operator (TSO) Association estimates new-build hydrogen pipeline costs to be almost nine times higher than for gas pipeline conversion.

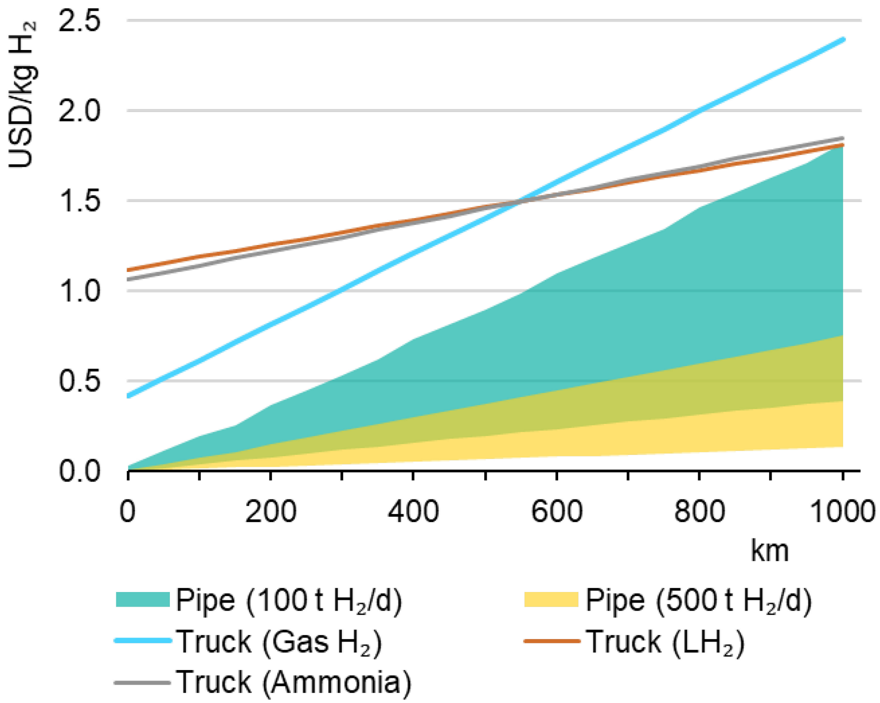
Most recently, the pre-feasibility study for a Danish-German Hydrogen Network estimated repurposing costs to be just 25% of those for new construction. Furthermore, the HyWay27 study, published in the Netherlands (June 2021), estimates that reusing existing natural gas pipelines is four times more cost-effective than laying new hydrogen pipelines. Lower construction costs would translate into more cost-competitive transport tariffs, further supporting deployment of low-carbon hydrogen.

Therefore, of the >1 200 km of hydrogen pipelines foreseen by 2030 in the German TSO Association's Ten-Year Network Development Plan (2020-2030), >90% is repurposed natural gas pipelines. At the end of June 2021, Gasunie announced that the Netherlands' State Secretary for Energy and Climate had requested it to develop a roll-out plan for a national hydrogen transport infrastructure by 2027. Project costs are estimated at EUR 1.5 billion with a throughput capacity of 10 GW, and the hydrogen network would consist of around 85% repurposed natural gas pipes. In September 2021, the Dutch government announced an investment of EUR 750 million (as part of a wider EUR 6.8 billion package on climate measures) to convert parts of the existing gas network into hydrogen transport infrastructure.

Construction cost comparison of repurposing natural gas pipelines vs building new hydrogen pipelines (%)



Estimated transport costs per unit of hydrogen via different types of transport



* Including compressor station CAPEX costs.

Notes: FNB = Vereinigung der Fernleitungsnetzbetreiber (TSO Association of Germany). LH_2 = liquefied hydrogen. In the right graph, the lower limit for pipeline costs corresponds to repurposing existing pipelines, the upper one to building new pipelines. Truck transport costs are based on a capacity of 10 t H_2/d; in the case of liquefied hydrogen and ammonia, they include conversion and reconversion costs.

Sources: Based on FNB (2020), Netzentwicklungsplan 2020; Gas For Climate (2021), European Hydrogen Backbone 2021; Gasunie-Energinet (2021), Pre-feasibility Study for a Danish-German Hydrogen Network.

Underground hydrogen storage in salt caverns and other geological formations

Availability of hydrogen as an energy vector could, like natural gas, enhance overall energy system flexibility by balancing short-term supply variability and meeting seasonal demand swings, thereby improving energy supply security. To fulfil this role, low-carbon hydrogen deployment will need to be coupled with development of cost-effective, large-scale and long-term storage solutions.

Global gas storage totalled >400 bcm in 2020 (10% of total consumption), with porous reservoirs (depleted fields and aquifers) accounting for >90% of storage capacity and the rest located in salt and rock caverns. Assuming global hydrogen demand reaches 530 Mt and a similar storage-to-consumption ratio, hydrogen storage requirements in the Net zero Emissions Scenario could amount to ~50 Mt (~550 bcm) by 2050.

Used by the petrochemical industry since the early 1970s, storing hydrogen underground in salt caverns is a proven technology. Because salt caverns support high injection and withdrawal rates, storing hydrogen there can provide short-term energy system flexibility. Their development, however, depends on geological conditions, i.e. the availability of salt formations. In addition, the injection-withdrawal periodicity of the petrochemical industry's use of underground hydrogen storage may differ from that of other applications, which could require faster cycles.

Four hydrogen salt caverns sites are currently operational. The first was commissioned in in 1972 at Teesside (United Kingdom) by Sabic Petrochemicals, and three are operational in Texas, including Spindletop (commissioned in 2016), the world's largest hydrogen storage facility.

Several pilot projects are under development in Europe: in the Netherlands, testing of hydrogen storage in the borehole of a future cavern in Zuidwending began in August 2021, with the first cavern to be operational in 2026. In Germany, EWE began building a smaller-scale salt cavern storage site at Rüdersdorf at the beginning of 2021, with first test results expected by mid-2022. In Sweden, a rock cavern hydrogen storage facility is under construction, with pilot operations expected to start in 2022. Several pilot projects are also in various stages of development in France and the United Kingdom.

In the United States, the proposed large-scale Advanced Clean Energy Storage (Utah) is targeting start-up in the mid-2020s. While there is no practical experience in repurposing methane caverns for hydrogen service, it is estimated that such an approach would require about the same amount of time as developing a new salt cavern.

While experience storing hydrogen in porous reservoirs such as depleted fields or aquifers is limited, demonstration projects in Austria (the Underground Sun Storage project) and Argentina (HyChico) show it is feasible to store a blend of 10% hydrogen and 90% methane in depleted fields without adversely affecting the reservoirs or equipment. Water aquifers are the least mature of the three geological storage options, and evidence of their suitability is mixed. The feasibility and cost of storing pure hydrogen in depleted reservoirs and aquifers still must be proven, requiring further research.

Another potential barrier is public opposition due to concerns about subsidence and induced seismicity, which should be investigated in depth to minimise risks. In parallel, adequate and transparent communication should address public concerns before large-scale storage site development begins. The IEA Hydrogen TCP is establishing a new task for underground hydrogen storage that will focus on research and innovation to prove its technical, economic and societal viability.

Existing hydrogen storage facilities and planned projects

Name	Country	Project start year	Operator/ developer	Working storage (GWh)	Type	Status
Teeside	United Kingdom	1972	Sabic	27	Salt cavern	Operational
Clemens Dome	United States	1983	Conoco Philips	82	Salt cavern	Operational
Moss Bluff	United States	2007	Praxair	125	Salt cavern	Operational
Spindletop	United States	2016	Air Liquide	278	Salt cavern	Operational
Underground Sun Storage	Austria	2016	RAG	10% H_2 blend	Depleted field	Demo
HyChico	Argentina	2016	HyChico, BRGM	10% H_2 blend	Depleted field	Demo
HyStock	The Netherlands	2021	EnergyStock	-	Salt cavern	Pilot
HYBRIT	Sweden	2022	Vattenfall SSAB, LKAB	-	Rock cavern	Pilot
Rüdersdorf	Germany	2022	EWE	0.2	Salt cavern	Under construction
HyPster	France	2023	Storengy	0.07-1.5	Salt cavern	Engineering study
HyGéo	France	2024	HDF, Teréga	1.5	Salt cavern	Feasibility study
HySecure	United Kingdom	mid-2020s	Storengy, Inovvn	40	Salt cavern	Phase 1 feasibility study
Energiepark Bad Lauchstädt Storage	Germany	-	Uniper, VNG ONTRAS, DBI Terrawatt	150	Salt cavern	Feasibility study
Advanced Clean Energy Storage	United States	mid-2020s	Mitsubishi Power Americas Magnum Development	150	Salt cavern	Proposed

Hydrogen trade

First steps under way to develop supply chains for international hydrogen trade

With the transition to sustainable energy systems boosting demand for hydrogen and hydrogen-based fuels, international trade in hydrogen will be an important part of the hydrogen supply chain. Countries that have limited domestic capabilities to produce low-carbon hydrogen from renewables, nuclear energy or fossil fuels with CCUS – or that find these processes too expensive – can benefit from importing more affordable low-carbon hydrogen.

For countries with excellent renewable resources, international trade in hydrogen can provide an opportunity to export renewable resources that otherwise may not be exploited. Similarly, gas- or coal-producing countries could join the market by exporting hydrogen produced from fossil fuels with CCUS. In the Net zero Emissions Scenario, international trade in hydrogen and hydrogen-based fuels covers ~15% of global demand for these fuels in 2030.

Transporting energy over long distances is typically easier in the form of molecules (i.e. liquid, gaseous or synthetic fuels) than as electricity because fuels are characterised by high (volumetric) energy densities and lower transport losses. Most natural gas is moved worldwide in large-scale pipelines or as LNG via ships, and similar methods could be employed for hydrogen and hydrogen carriers. Hydrogen can also be transported in storage tanks by trucks, which is currently the main option to distribute it at the local level, but it is generally very expensive. For longer distances, pipelines and seaborne transportation are more economical, with the best option dependent on distance and volume (among other factors).

At present, hydrogen is generally stored as a compressed gas or in liquefied form in tanks for small-scale local use. However, a much wider variety of storage operations will be required to achieve uninterrupted international hydrogen trading. At import terminals, hydrogen storage is likely necessary as a contingency measure in case of supply disruptions, similar to the approach for LNG.

Various solutions are being explored for long- or short-distance seaborne hydrogen transport. One option is to transport it in liquefied form, which is drastically more dense than the gaseous state. However, as hydrogen liquefaction requires a temperature of -253°C (i.e. 90°C lower than for LNG), it is energy-intensive. Plus, current liquefaction processes have a relatively low efficiency and consume about one-third of the energy contained in the hydrogen. Some reports indicate that scaling up liquefier capacity could cut energy requirements to around one-fifth.

Another option for high-density transport is to convert hydrogen into another molecule such as ammonia or LOHC. Ammonia is already traded internationally as a chemical product, but as it is toxic, increased transport and use may raise safety and public acceptance issues, restricting its handling to professionally trained operators.

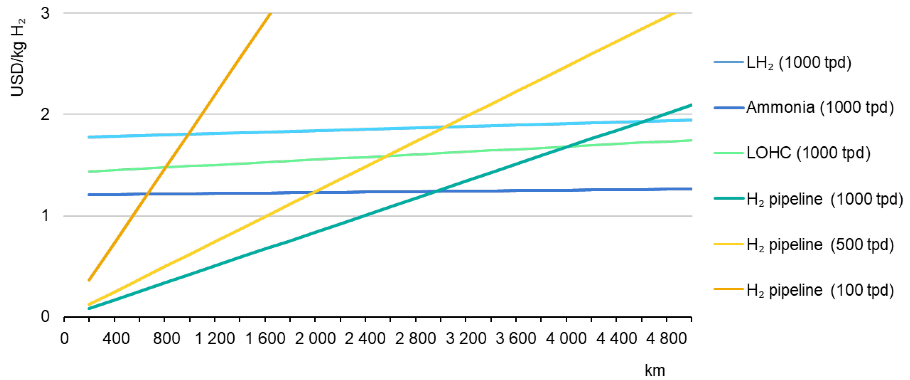
Converting hydrogen into ammonia and reconverting it back to hydrogen after transport is possible, but additional energy and purification steps will be required for some end uses. Still, the advantage of ammonia is that it liquefies at -33°C (at ambient pressure), a much higher temperature than hydrogen, resulting in a lower energy needs.

LOHCs have properties similar to crude oil and oil products, and their key advantage is that they can be transported without liquefaction. As with ammonia, conversion/reconversion and purification processes are costly, and depending on an LOHC's basic molecular makeup, toxicity issues could be a consideration. Furthermore, an LOHC's carrier molecules are often expensive and, after being used to transport hydrogen to its destination, need to be shipped back to their place of origin.

The high cost of hydrogen transmission and distribution for many trade routes means it may cost less to produce low-carbon hydrogen domestically than to import it – i.e. the higher cost of clean hydrogen production could still be less than the supply costs incurred for imports. This depends heavily on local conditions. Countries with constrained CO_2 storage or limited renewable resources will be more dependent on imports to meet hydrogen demand.

In 2020, significant progress was made in demonstrating international hydrogen trade. The Advanced Hydrogen Energy Chain Association for Technology Development successfully produced and traded hydrogen by LOHC technology from Brunei to Japan using container shipping, for use as a gas turbine fuel. Meanwhile, Saudi Aramco and the Institute of Energy and Economic of Japan collaborated to import 40 t of ammonia produced in Saudi Arabia from natural gas with CCUS to Japan for direct use as an electricity generation fuel. For liquefied hydrogen (LH_2), the first planned shipment from Australia to Japan in the Hydrogen Energy Supply Chain (HESC) pilot project was postponed to the first quarter of 2022 due to the Covid-19 pandemic. Still, the import terminal and hydrogen production plant were commissioned, and the hydrogen was successfully produced and liquefied in Australia.

Costs of delivering GH_2 by pipeline and LH_2, LOHC and ammonia by ship, 2030



Notes: GH_2 = gaseous hydrogen. LH_2 = liquefied hydrogen. LOHC = liquid organic hydrogen carrier. tpd = tonnes per day. Includes conversion, export terminal, shipping, import terminal and reconversion costs for each carrier system. Storage costs are included in import and export terminal expenses. The pipeline cost assumes construction of a new pipeline.

Sources: Based on IAE (2016); Baufumé (2013).

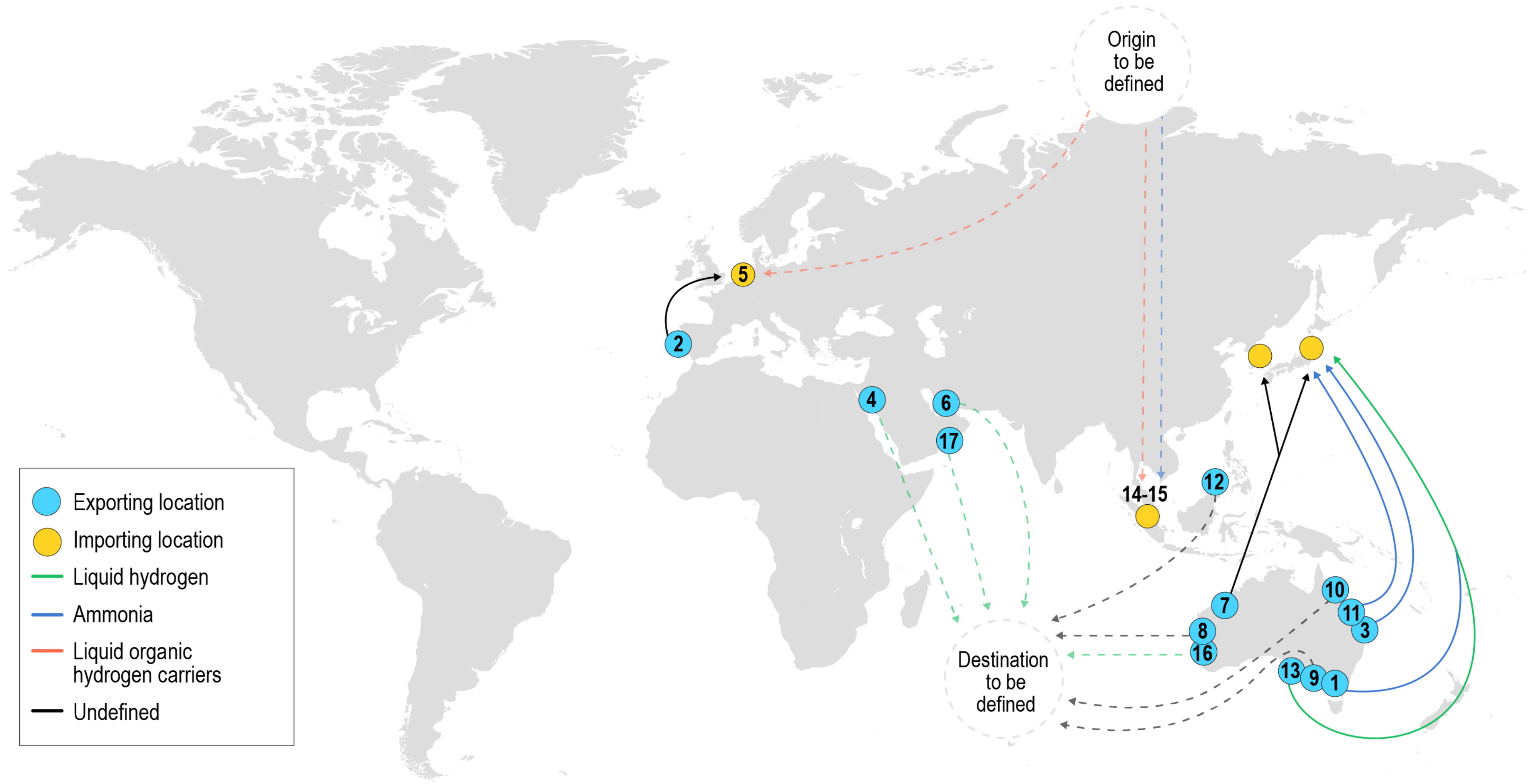
Governments and private companies have also announced several other international collaborations and projects for hydrogen trade. Germany, which stated the importance of importing hydrogen in its national strategy, signed an agreement for a joint feasibility study with Australia and Chile. Meanwhile, the Netherlands signed an MOU with Portugal, the Port of Rotterdam signed one with Chile, and Japan signed a memorandum of collaboration (MOC) with the United Arab Emirates. Around 60 international hydrogen trade projects have been announced and feasibility studies are under way for half of them. The total reported volume of these projects is 2.7 Mt H_2/yr.

Selected international hydrogen trade projects

Project	Export country	Import country	Volume	Carrier	Expected first shipping year	Map Reference
Hydrogen Energy Supply Chain	Australia	Japan	225 540 tpa	LH_2	2030	1
H2 Sines	Portugal	Netherlands	TBD	TBD	TBD	2
Stanwell - Iwatani Gladstone project	Australia	Japan	280 000 tpa	LH_2	2026	3
Helios Green Fuels	Saudi Arabia	TBD	650 tpd	Ammonia	2025	4
H2Gate	TBD	Netherlands	1 000 000 tpa	LOHC	TBD	5
ADNOC - TA'ZIZ industrial hub	United Arab Emirates	TBD	175 000 tpa	Ammonia	2025	6
Asian Renewable Energy Hub	Australia	Japan or Korea	TBD	LH_2 or ammonia	2028	7
Murchison	Australia	TBD	TBD	TBD	TBD	8
Crystal Brook Energy Park	Australia	TBD	25 tpd	TBD	TBD	9
Pacific Solar Hydrogen	Australia	TBD	200 000 tpa	TBD	TBD	10
Origin Energy - Kawasaki Heavy Industries Townsville project	Australia	Japan	36 000 tpa	LH_2	2025	11
KBR SE Asia feasibility study	Southeast Asia	TBD	TBD	TBD	TBD	12
Eyre Gateway	Australia	Japan or Asia	7 000 tpa	Ammonia	TBD	13
Unnamed	TBD	Singapore	TBD	LH_2	TBD	14
Unnamed	TBD	Singapore	TBD	LOHC	TBD	15
Project Geri	Australia	TBD	175 000 tpa	Ammonia	TBD	16
Green Mega Fuels Project	Oman	TBD	175 000 tpa	Ammonia	2032	17
Western Green Energy Hub	Australia	TBD	34 000tpa	Ammonia	TBC	18

Notes: LH_2 = liquefied hydrogen. LOHC = liquid organic hydrogen carrier. SE Asia = Southeast Asia. TBD = to be determined. tpa = tonnes per annum. tpd = tonnes per day.

Most hydrogen trade projects under development are in Asia-Pacific



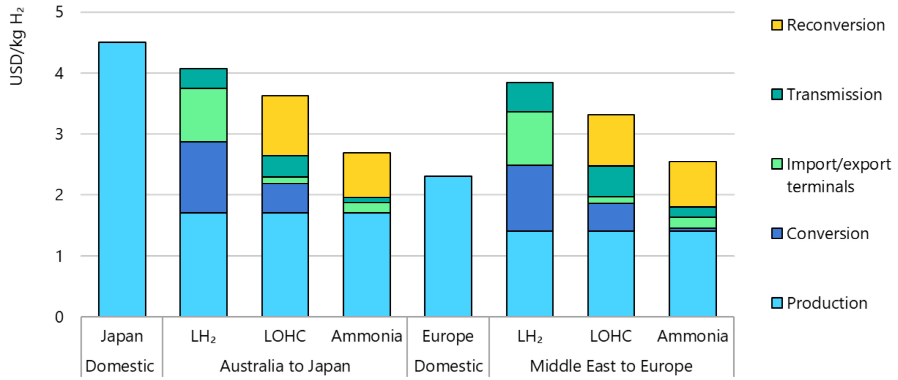
Notes: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

As part of its JPY 2-trillion (about USD 18.7-billion) Green Innovation Fund, the Japanese government has allocated JPY 255 billion (about USD 2.4 billion) to establish the first commercial international hydrogen trade. Its intent is to support LH_2 and LOHC supply chain development to reduce costs and improve the maturity of the technologies involved.

Any country deciding whether to produce hydrogen domestically or import must consider all delivery costs across the entire supply chain, from production and transport to end-use application. The IEA estimates that by 2030, importing hydrogen produced from solar PV in Australia into Japan (<USD 4.20/kg H_2) will cost slightly less than producing it domestically from renewables (USD 4.50/kg H_2). While producing natural gas-derived hydrogen with CCUS in Japan could cost even less (USD 1.85/kg H_2), access to CO_2 storage may be a limiting factor.

In the case of exporting hydrogen from the Middle East to Europe, imported hydrogen (USD 2.60-3.80/kg H_2) is unlikely to be competitive with domestic production (USD 2.30/kg H_2) in 2030. However, if ammonia can be used directly (e.g. in the chemical industry or as a shipping or power sector fuel), reconversion losses can be avoided and the supply cost could be reduced to USD 1.80/kg H_2 for these trade links, which would be competitive. In the long term, further efficiency improvements and process optimisation could reduce transport and thus total supply costs for all carriers. In some regions, this could eventually make imports more attractive than domestic production, potentially boosting international trade after 2030.

Projected costs of delivering LH_2, LOHC and ammonia in selected regions, 2030



Notes: LH_2 = liquefied hydrogen. LOHC = liquid organic hydrogen carrier. Assumes distribution of 1 000 t H_2/d. Storage costs are included in import and export terminal expenses. Hydrogen is produced from electrolysis using renewable electricity.
Source: Based on IAE (2016).

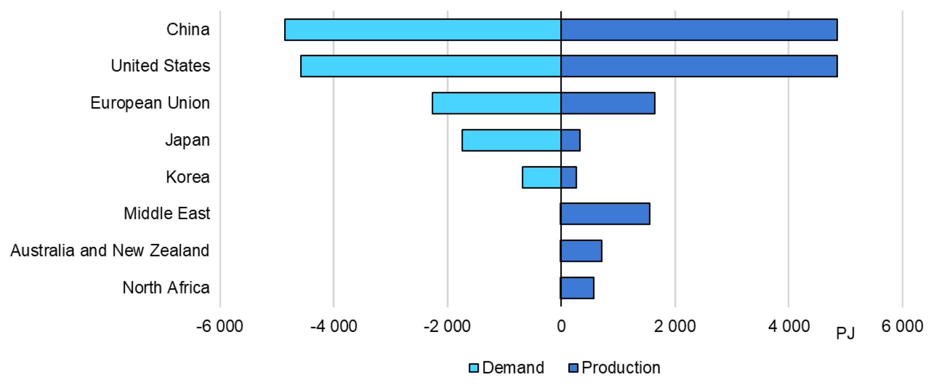
Long-term potential of international hydrogen trade

In the Announced Pledges Scenario in 2050, trade in hydrogen and hydrogen-based fuels accounts for 20% of global demand, with 8% of hydrogen demand being traded, 50% of ammonia and 40% of liquid synfuels. This reflects the comparatively lower transport costs of ammonia and synfuels. While several countries (e.g. China and the United States) manage to cover growing demand for low-carbon hydrogen and hydrogen-based fuels domestically, others (e.g. Japan, Korea and parts of Europe) rely on imports, at least in part. By 2050 in the Announced Pledges Scenario, Japan and Korea are importing each around 60% of their domestic demand for hydrogen and hydrogen-based fuels.

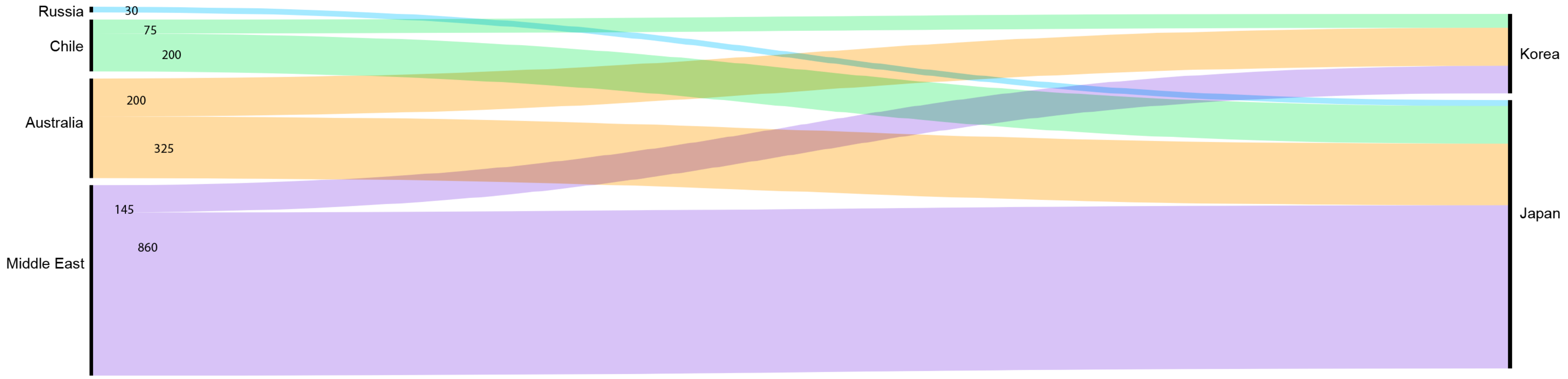
Australia, Chile, the Middle East and North Africa emerge as key exporting regions in the Announced Pledges Scenario, benefitting from the low cost of producing hydrogen from renewables or from natural gas with CCS. By 2050, North Africa, the Middle East and Chile export ~600 PJ of hydrogen and hydrogen-based fuels to Europe. For Asia, the important hydrogen suppliers are the Middle East, Australia and Chile. By 2050, these exporters meet 1 800 PJ of Asian demand for hydrogen and hydrogen-based fuels in the Announced Pledges Scenario.

However, many of these major future exporters do not yet have net zero pledges in place, so importing countries will need to engage with trading partners to encourage and guarantee relevant supply investments if they want their hydrogen imports to be low-carbon.

Announced Pledges Scenario hydrogen and hydrogen-based fuel demand and production in selected regions, 2050



Hydrogen trade flows to Japan and Korea in the Announced Pledges Scenario in 2050



Investments and innovation

Hydrogen investments rising despite Covid-19 pandemic, with unprecedented private fundraising, mostly for manufacturing and to meet project demand

Hydrogen has proven remarkably resilient during the economic slowdown induced by the global pandemic. Companies specialised in producing, distributing and using hydrogen raised almost USD 11 billion in equity between January 2019 and mid-2021 – a considerable increase from prior years – and contracts funded by government recovery packages are expected to raise project investments substantially. Nevertheless, funding is grossly insufficient to accelerate innovation to the level required to realise hydrogen's 60 Gt of CO_2 emissions reduction potential modelled in the Net zero Emissions Scenario.

Overview of recent company fundraising

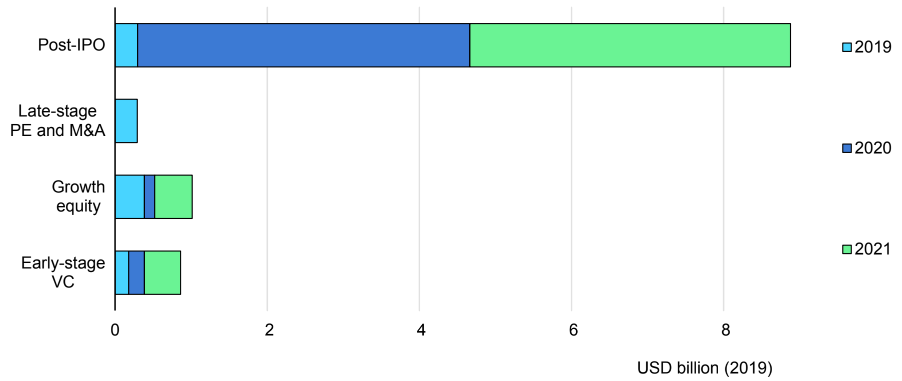
Most new funding for hydrogen in 2020 and 2021 was raised by companies already listed on a stock exchange. They issued new shares to investors, primarily to secure capital for expanding manufacturing facilities to meet expected or contracted demand for electrolysers and fuel cells. Investor confidence in hydrogen companies continued into the first half of 2021, partly in anticipation of contracts to be supported by government recovery packages.

Having sold USD 4.8 billion in new shares since 2019, the largest fundraiser was Plug Power, a US company (est. 1997) that makes electrolysers, fuel cells and refuelling equipment. Other electrolyser manufacturers – including Nel, ITM Power, McPhy Energy, Green Hydrogen Systems and Sunfire – collectively raised USD 1.5 billion. Nikola, a company developing a fuel cell truck, raised USD 250 million in 2019, then listed on the Nasdaq in 2020, raising USD 700 million. In November 2020, however, a deal to sell 11% of its shares to GM for USD 2 billion fell through. Investors have since become increasingly concerned about Nikola's ability to meet its development schedule.

Two notable acquisitions occurred in this period. US engine manufacturer Cummins bought the Canadian electrolyser company Hydrogenics for USD 290 million. In Germany, engine manufacturer MAN Energy Solutions acquired the PEM electrolyser maker H-Tec for an undisclosed sum.

Several investment funds targeting hydrogen were launched in 2021. The most recent, HydrogenOne Capital Growth Fund, raised USD 150 million in an initial public offering including USD 35 million from the petrochemical company INEOS. Other funds established since 2018 include Ascent, FiveT, H-Mobility, Klima and Mirai. In China, Shanxi Hydrogen Energy Industrial Fund, a government-guided fund, was launched in 2021.

Hydrogen company fundraising by stage of funding, January 2019 to mid-July 2021



Notes: PE = private equity. M&A = mergers and acquisitions. VC = venture capital. Post-IPO includes private investment in public equity (PIPE) transactions and other new share sales. Early-stage VC includes seed, Series A and Series B. Only deals with disclosed values are included, which notably excludes certain M&A deals with undisclosed values.
Sources: Calculations based on Cleantech Group (2021) and Prequin (2021).

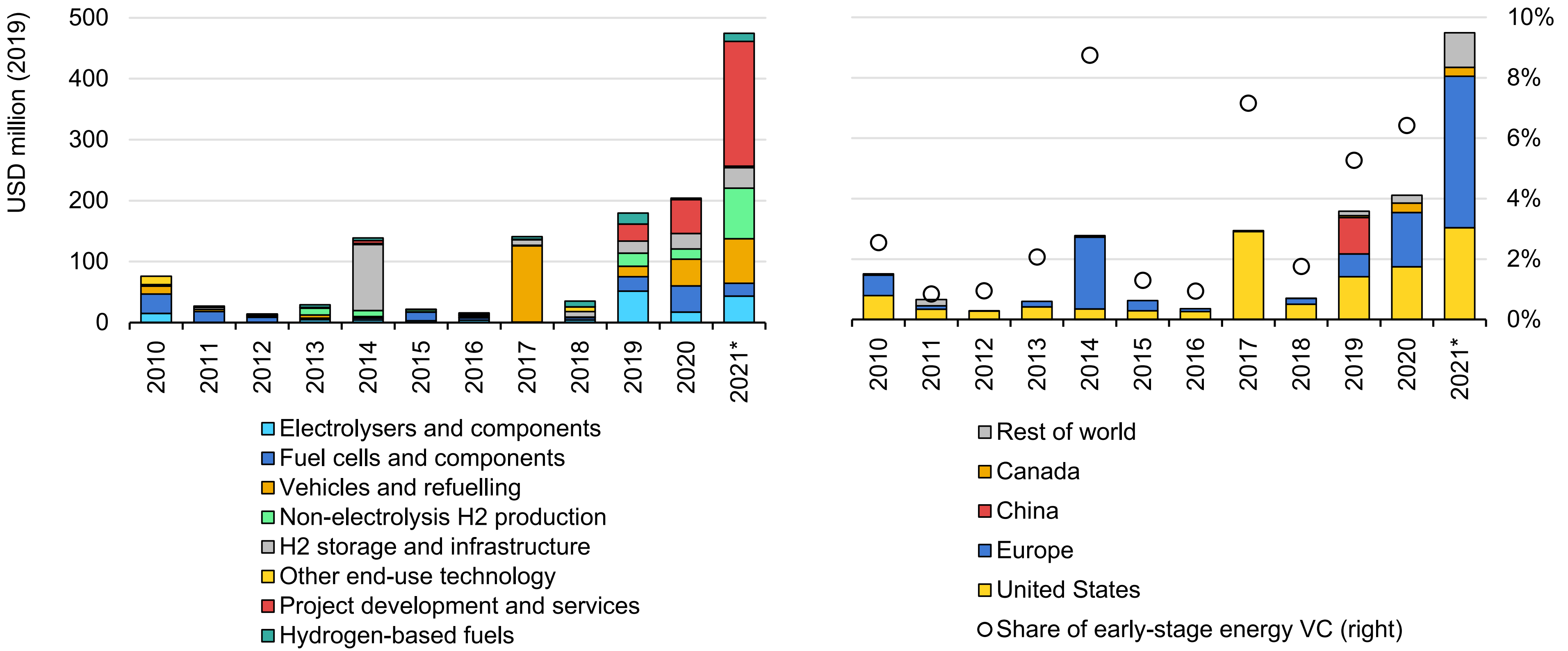
Investment in riskier early-stage hydrogen start-ups is also on the rise. In contrast to the clean energy venture capital (VC) boom around 2010, which involved few hydrogen companies, the current investment surge delivered record amounts in 2019 and 2020, with these sums surpassed in just the first six months of 2021. As electrolyser companies become more established in the market, start-up activity is shifting to focus on newer non-electrolysis routes, such as pyrolysis for extracting hydrogen from methane. Transform Materials and Syzygy Plasmonics have raised USD 50 million since 2019, while Monolith Materials raised USD 100 million in 2021 in later-stage financing.

The fact that start-ups providing project development and integration services for hydrogen projects are securing funding indicates a maturing sector. In May 2021, H2 Green Steel raised over USD 100 million, the first major deal for a project developer for hydrogen use in the steel industry. Aiming to start production by 2024, the Swedish company plans follow-up funding of USD 2.5 billion in mixed debt and equity within the next year. HTEC, an early-stage Canadian integration services firm, raised USD 170 million in September 2021.

Regionally, many start-ups in these newer areas are European. For the first time, in fact, European hydrogen start-ups are expected to raise more early-stage funds in 2020 and 2021 than their US counterparts. China has also emerged as a source of hydrogen technology start-ups and venture capital for scale-up. In 2019, Jiangsu Guofu Hydrogen Technology's fundraise of USD 60 million was the main early-stage deal in China, with the money coming from a state-backed Shanghai fund.

More early-stage capital flowing to start-ups, especially in Europe; fastest growth in companies offering project development services or non-electrolysis supply solutions

Early-stage venture capital deals for hydrogen-related start-ups by technology area and region, 2010-2021



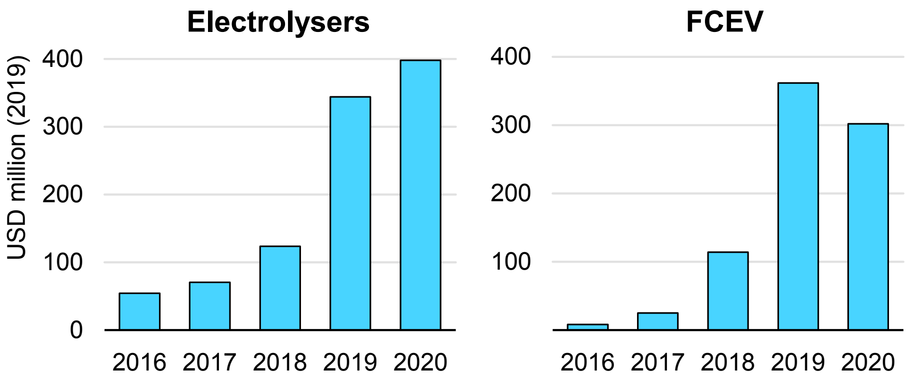
Notes: 2021* data up to mid-June. H2 = hydrogen. Early-stage VC includes seed, Series A and Series B. The share of early-stage energy VC excludes outlier deals above USD 150 million that distort trends (no such deal was recorded for hydrogen start-ups). Other end-use technology includes stationary turbines and non-transport mobile applications that do not involve proprietary fuel cell stacks.

Source: Calculations based in part on Cleantech Group (2021).

Evolution of investment in technology deployment

Investment in hydrogen technology deployment is also increasing. Despite near-term uncertainty about market-led uptake, hydrogen prospects look stronger than before the Covid-19 pandemic. Projects expected to deploy electrolysis capacity in 2021 raised more than USD 400 million in 2020, nearly four times the investments in 2018. In mobility, 2020 funding decreased slightly from 2019, likely reflecting impacts of the pandemic; investment is more than recovering in 2021, however, and deployments up to June point to a new record year.

Annual investments in electrolysers and FCEVs, 2016-2020



Note: FCEV = fuel cell electric vehicle.
Sources: Based on IEA Hydrogen Project Database and annual data submissions of the AFC TCP to the IEA Secretariat.

Clearly, government action – including funding in Covid-19 recovery plans and long-term signals embedded in national hydrogen strategies – is spurring the strong momentum behind hydrogen investment. Public investment is expected to leverage much higher private spending, which could further accelerate hydrogen technology deployment. For example, as part of its national hydrogen strategy, Germany announced a EUR 9-billion package, which the German government expects to trigger an additional EUR 33 billion of private investment. Globally, the industry sector is responding with an impressive investment appetite: according to the Hydrogen Council, the private sector has announced more than USD 300 billion of investments through 2030, although funding of only USD 80 billion has been committed.

Investment outlook for the Announced Pledges and Net zero Emissions scenarios

While recent hydrogen investments are encouraging, realising government climate ambitions will require significant ramp-ups across the entire production, end-use and infrastructure value chains. The Announced Pledges Scenario models investments totalling USD 250 billion for 2020-2030, leading to an accumulated investment of USD 3.2 trillion in 2050. This is lower than announced industry stakeholder investments to 2030, but significantly larger than those for which funding has already been committed.

Investments over the next decade could be critical in determining long-term outcomes. Every year until 2030, investments of USD 7 billion in electrolysers will be required (30 times recent record investments) and USD 4 billion in FCEV deployment will be needed (14 times record investments). To achieve net zero emissions by

2050, global cumulative investments must increase to USD 1.2 trillion by 2030 and USD 10 trillion by 2050.

Building up low-carbon hydrogen production capacity accounts for 25% of global cumulative investments to 2050 in the Announced Pledges Scenario and 27% in the Net zero Emissions. The need to deploy capacity for both new production and to decarbonise existing uses (which requires limited investments in end uses and infrastructure) means the share of investments in hydrogen production must be higher before 2030 than after. Although investment in production capacity continues to grow to 2050, its share declines as investments in new end-uses and infrastructure development increase.

End-use technologies account for about 60% of global cumulative investments to 2050 in both the Announced Pledges and Net zero Emissions scenarios, with the share increasing continuously. Investments in end-use technologies are already considerable in 2020-2030, projected at USD 8 billion/yr in the Announced Pledges Scenario and USD 30 billion in the Net zero Emissions. After 2030, several end-use technologies advance from early-stage development to commercialisation and deployment at scale, unlocking new hydrogen demand, particularly in the transport sector. Consequently, investments increase substantially to USD 90 billion/yr to 2050 in the Announced Pledges Scenario and to USD 270 billion/yr in the Net zero Emissions.

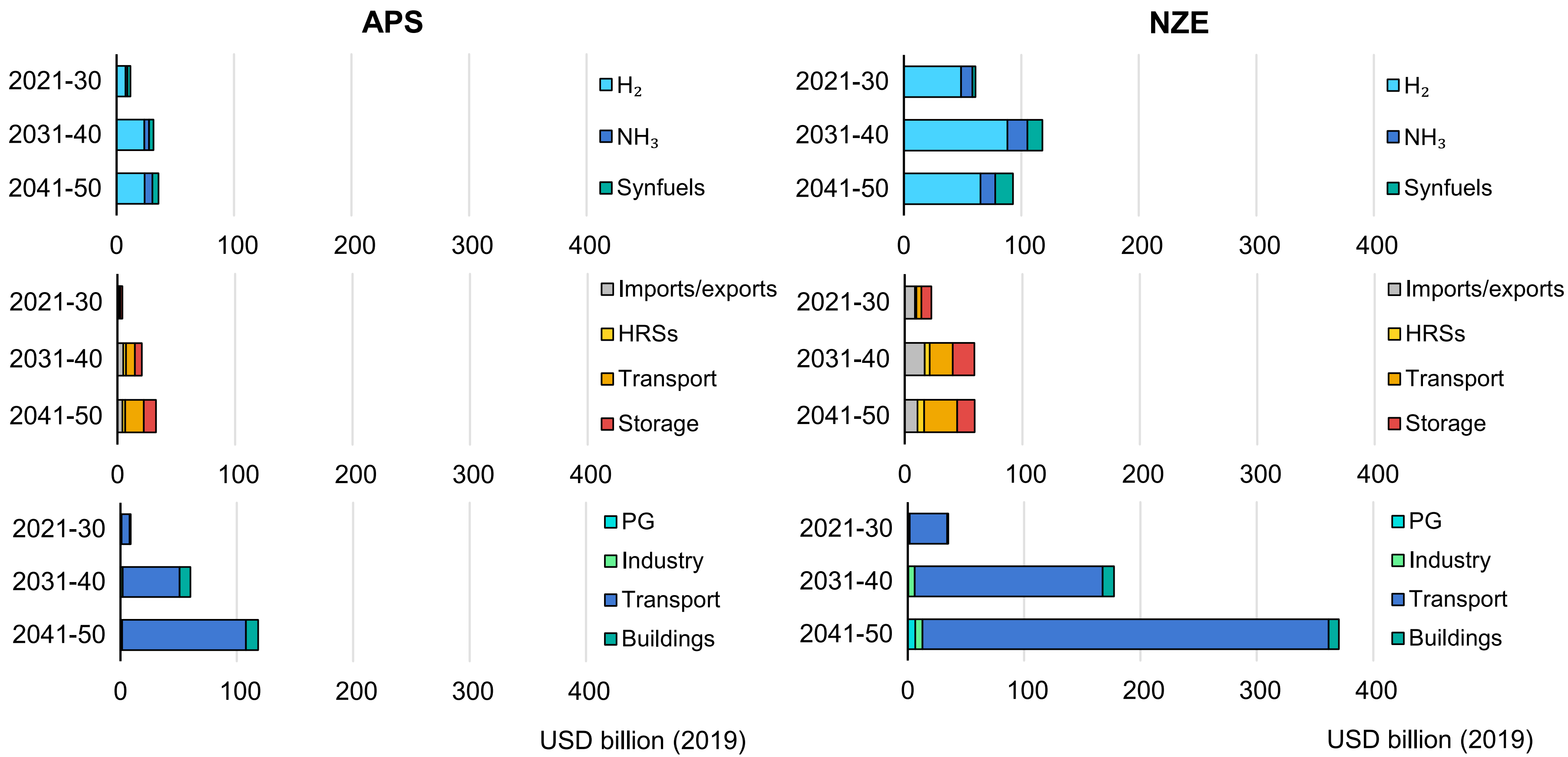
To distribute hydrogen to end users, significant investments are also required to develop infrastructure (i.e. refuelling stations, pipelines, storage and import/export terminals). In fact, infrastructure accounts for 18% of global cumulative investments to 2050 in the Announced Pledges Scenario (USD 575 billion) and 14% in the Net zero Emissions (USD 1 400billion).

Although modelling shows this share increasing nearly fivefold after 2030 in the Announced Pledges Scenario and more than twofold in the Net zero Emissions, this does not mean that infrastructure development can be delayed another decade. Rather, developing hydrogen storage capacity will be critical to ensure supply security in the short term and to provide balancing for the integration of renewable energy in the longer term. In parallel, progress can be made by blending hydrogen in the gas grid and repurposing natural gas pipelines. As hydrogen demand grows, greater investments in new pipeline infrastructure may be required, depending on regional conditions. Furthermore, the development of international hydrogen supply chains can spur investment in import/export terminals and hydrogen transport vessels.

Notable opportunities may exist to minimise expenditures by repurposing current infrastructure. With minimal modification, infrastructure for oil-derived products could be used to import/export liquid synfuels, while some parts of LNG and LPG infrastructure could be upgraded to import/export hydrogen and ammonia.

Investment on hydrogen must increase to USD 1.2 trillion by 2030 to put the world on track to meet net zero emissions by 2050

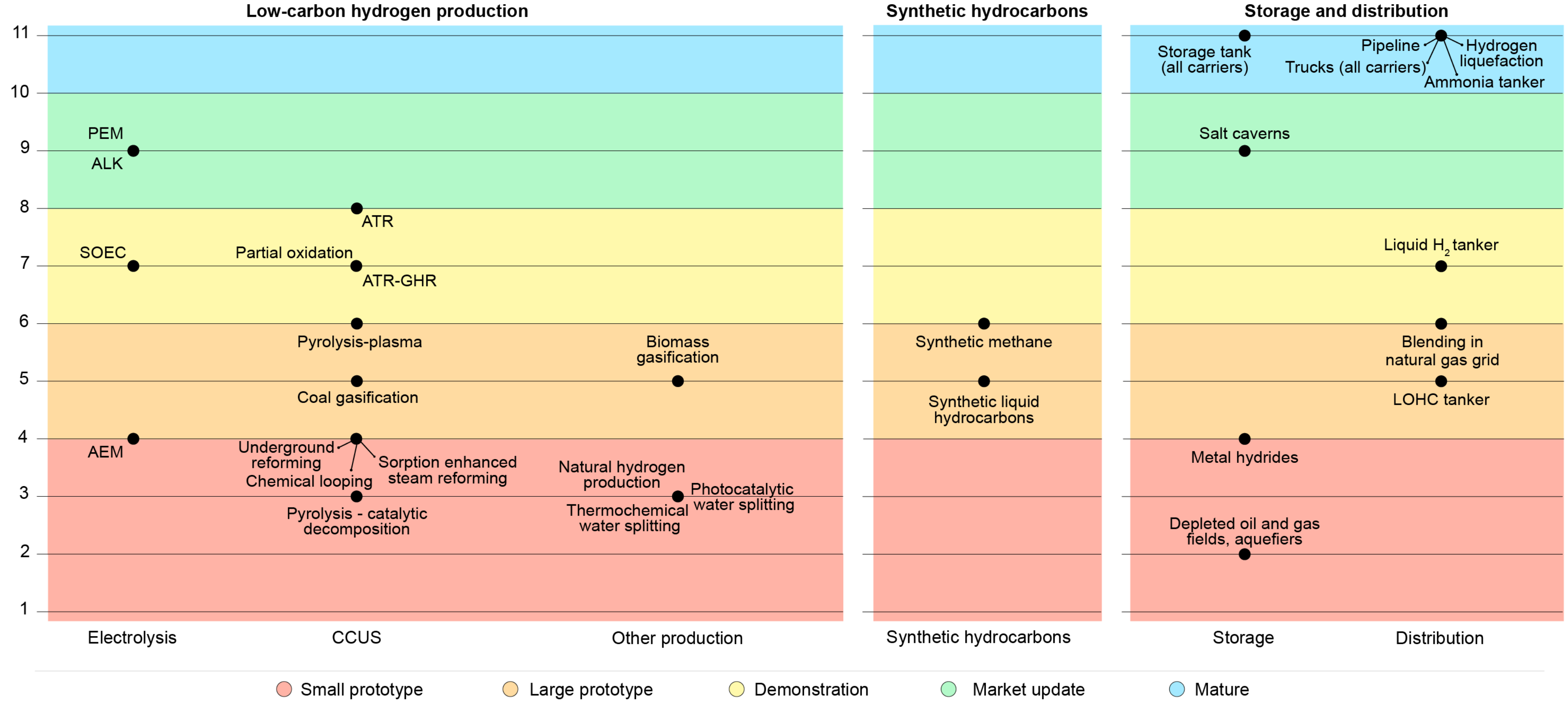
Global annual hydrogen investment needs by sector in the Announced Pledges and Net zero Emissions scenarios



Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. HRSs = hydrogen refuelling stations. PG = power generation.

Several hydrogen technologies not yet commercially available

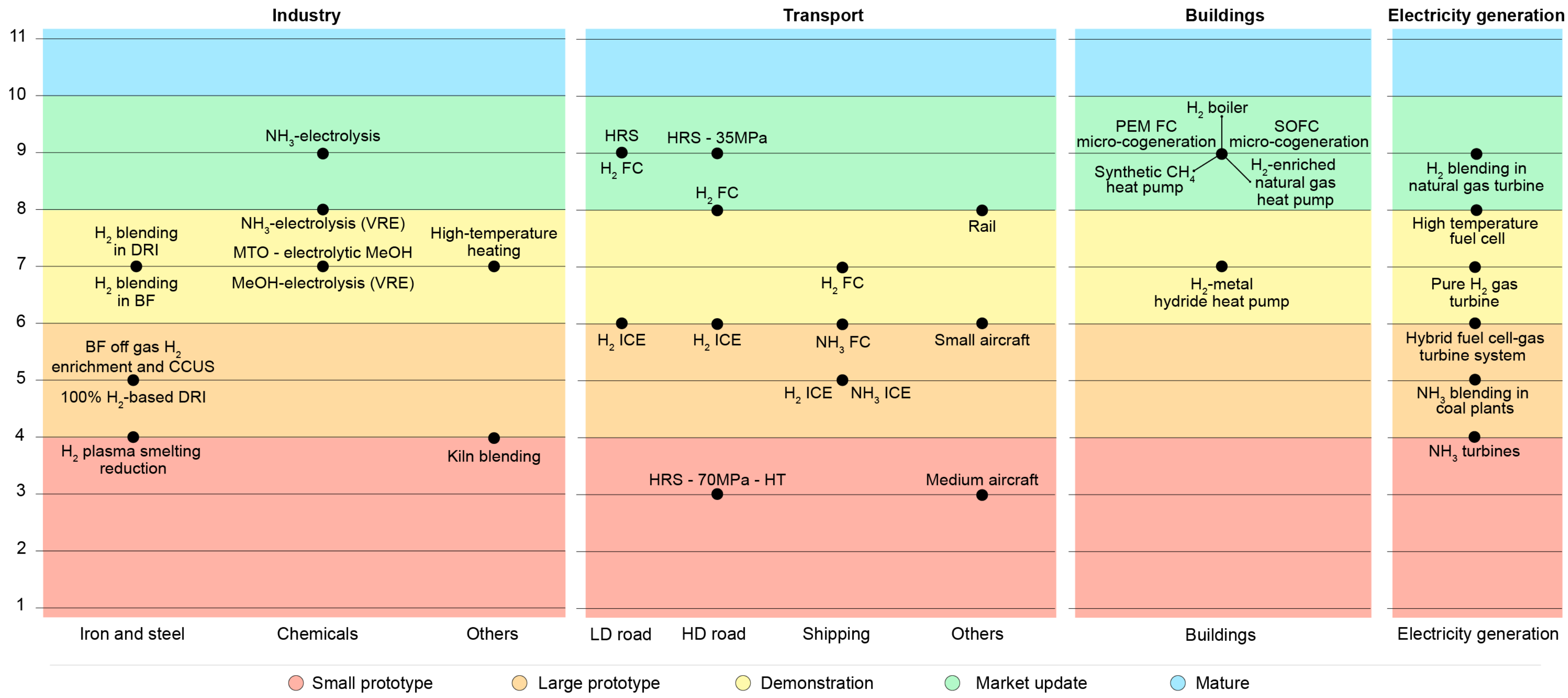
Technology readiness levels of key hydrogen production, storage and distribution technologies



Notes: AEM = anion exchange membrane. ALK = alkaline. ATR = autothermal reformer. CCUS = carbon capture, utilisation and storage. GHR = gas-heated reformer. LOHC = liquid organic hydrogen carrier. PEM = polymer electrolyte membrane. SOEC = solid oxide electrolyser cell. Biomass refers to both biomass and waste. For technologies in the CCUS category, the technology readiness level (TRL) refers to the overall concept of coupling these technologies with CCUS. TRL classification based on Clean Energy Innovation (2020), p. 67.

Source: IEA (2020), ETP Clean Energy Technology Guide.

Technology readiness levels of key hydrogen end-use technologies



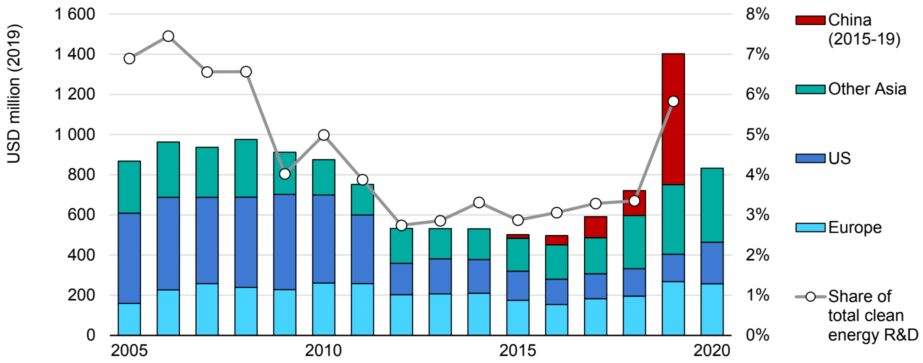
Notes: BF = blast furnace. DRI = direct iron reduction. FC = fuel cell. HRS = hydrogen refuelling station. HD = heavy-duty. HT = high throughput. ICE = internal combustion engine. LD = light-duty. MeOH = methanol. MTO = methanol to olefins. PEM FC = polymer electrolyte membrane fuel cell. SOFC = solid oxide fuel cell. VRE = variable renewable electricity. Co-generation refers to the combined production of heat and power. Technology readiness levels based on Clean Energy Innovation (2020), p. 67.

Source: IEA (2020), ETP Clean Energy Technology Guide.

Innovation in hydrogen technology is lagging

Except for well-established technologies for fossil-based production and conventional uses in industry and refining, much of the hydrogen value chain is yet to be fully developed at commercial scale. It is therefore vital that innovation efforts for all hydrogen technologies be stepped up to avoid bottlenecks in using them as a key lever for decarbonisation. In its Net zero by 2050 roadmap, the IEA estimates that USD 90 billion of public money needs to be mobilised globally as quickly as possible, with around half dedicated to hydrogen-related technologies.

R&D spending in hydrogen technologies, 2005-2020



Source: Based on IEA and Mission Innovation data. 2020 data for China not available.

Government support for hydrogen R&D was strong in the late 2000s. In fact, it accounted for 6% of all clean energy R&D, with most funding directed towards electrolyser technology and Japan being the largest funder. While a slump in R&D expenditures during 2010-2015 reflected lower overall interest in this technology family, the recent resurgence (since 2015) has focused on other hydrogen production and end-use technologies, in line with the relative maturity of fuel cell technologies. Of particular note is that the Government of China's R&D expenditures on hydrogen technologies increased sixfold in 2019.

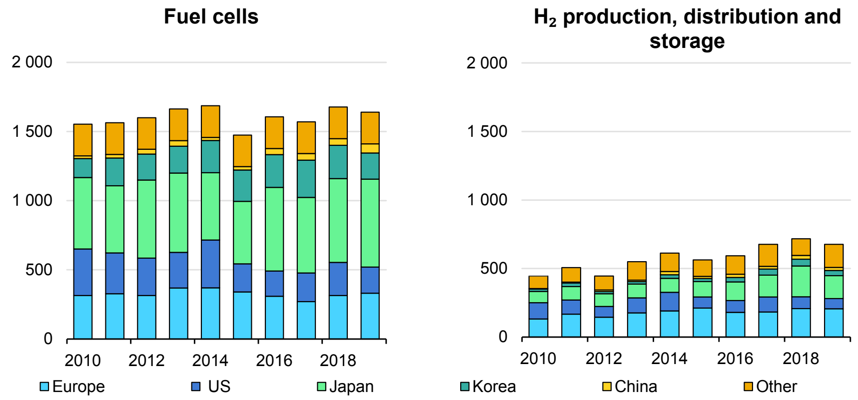
While the technology readiness levels (TRLs) of low-carbon hydrogen production technologies vary widely, analysis reveals that innovation gaps are concentrated in novel end-use industrial applications, heavy road transport, shipping and aviation. Among these technologies, the most advanced are in the early adoption stage, meaning they are ready for commercial applications but have not yet obtained significant market shares. Storage and distribution, use in buildings and light-duty road transport are all sufficiently developed for initial hydrogen use.

International patent family counts are a good proxy to measure innovation activity in any given technology. The 676 patent families registered for hydrogen production, storage and distribution technologies in 2019 reflect a 52% increase since 2010. In 2019, the highest shares of new patents were in Europe (30%) and Japan (25%).

At present, patents for fuel cell technologies outnumber those for hydrogen production, storage and distribution by a ratio of nearly 3:1, likely reflecting a higher TRL for the former as well the fact that fuel cell patent applicants include large companies (such as car manufacturers) with large R&D budgets. Japan has a clear technological lead in fuel cells, holding 39% of all patents, and the number of patent applications has been roughly constant over the past decade. Electrolyser manufacturers, in comparison, tend to be smaller companies with lower R&D budgets. Their technologies can, however, benefit from progress in fuel cells, particularly in areas such as materials or catalysts.

As public funding has been shared roughly equally between fuel cells and other applications, one can infer that the private sector has driven most of the innovation activity for fuel cells. A forthcoming study about patenting activity in hydrogen, developed jointly by the IEA and the European Patent Office, will be released in early 2022.

Patent applications by sector and region, 2010-2019



Source: Based on European Patent Office data.

Innovation and demonstration urgently needed to unlock emissions reduction potential of hydrogen technologies

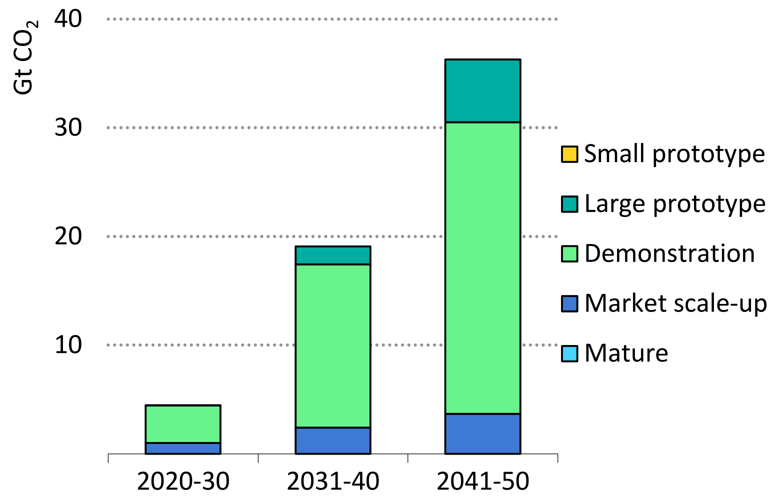
Of the 60 Gt of CO_2 emissions that hydrogen-based fuels can avoid in the Net zero Emissions Scenario, 55 Gt are achieved after 2030, reflecting that most end-use technologies for such fuels are not yet commercially available. Assessing TRLs across the entire hydrogen supply chain and in end-use sectors confirms the need to ramp up innovation to stay on track with this scenario.

Ultimately, only 12% of cumulative emissions reductions to 2050 come from technologies that are ready to enter the market and scale up production (e.g. light commercial vehicles). Most emissions reductions come from critical technologies still being developed and requiring demonstration to reach commercialisation, including co-firing ammonia and hydrogen in coal and natural gas power plants; producing chemicals using electrolytic hydrogen; using hydrogen in heavy-duty vehicles; and using hydrogen and ammonia in shipping.

In the Net zero Emissions Scenario, these technologies start delivering important CO_2 emissions reductions as early as the 2020s. While several ongoing initiatives aim to demonstrate these technologies, innovation efforts should be stepped up to ensure they reach commercialisation soon.

Other key technologies, such as using hydrogen-based DRI for steel manufacturing, are at even earlier stages of development. Their innovation cycle to reach demonstration and commercialisation should be completed as soon as possible so that they can begin effectuating CO_2 emissions reductions in the early 2030s.

Global CO_2 emissions reductions from hydrogen-based fuels by technology maturity in the Net zero Emissions Scenario, 2020-2050



Regional insights

United States: Stepping up efforts to develop hydrogen technologies

Owing to its large refining and chemical sectors, the United States is already one of the largest producers and consumers of hydrogen. With more than 11 Mt H_2/yr of consumption, the United States accounts for 13% of global demand: two-thirds is used in refining with most of the rest going into ammonia production. Around 80% of US hydrogen production is based on natural gas reforming; practically all the remainder is met with by-product hydrogen in refineries and the petrochemical industry.

The United States has been a traditional supporter of hydrogen as an energy vector and a main advocate for the adoption of hydrogen technologies in previous waves of interest. In the early 2000s, the US government strongly promoted R&D on hydrogen and fuel cells, with federal funding peaking at USD 330 million in 2007.

After a period of lower activity, the government again stepped up efforts, and in 2016 the US Department of Energy introduced its H_2@Scale initiative to enable affordable and clean hydrogen across end-use sectors (transport, metal refining, electricity generation, heating, ammonia and fertilisers, etc.) from diverse domestic resources, including renewables, nuclear energy and fossil fuels.

Instead of setting deployment targets, this programme focuses on cost and performance targets that can enable the adoption of hydrogen technologies. In 2020, the DOE Hydrogen Program Plan established a framework to encourage R&D on hydrogen-related technologies and eliminate institutional and market barriers to adoption across multiple applications and sectors.

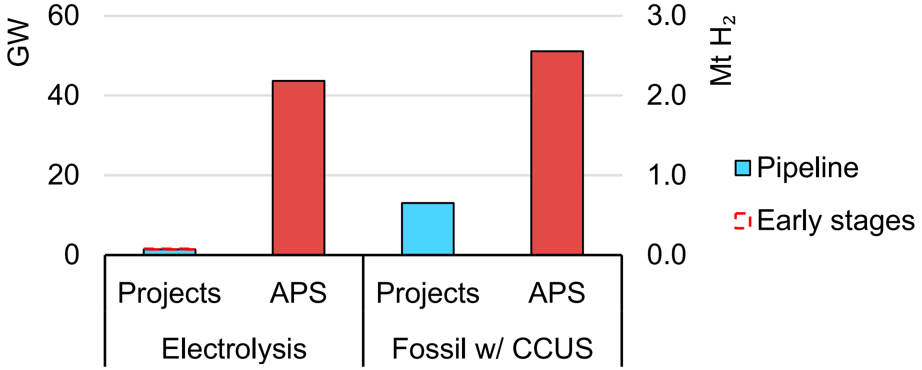
More recently (June 2021), the DOE announced Hydrogen Energy Earthshot, an ambitious initiative to slash the cost of clean hydrogen by 80% – to USD 1.00/kg H2 – by 2030. By doing this, the US government expects to unlock a fivefold increase in demand for clean hydrogen. Previous economic analysis from the National Renewable Energy Laboratory (NREL) shows detailed scenarios for expanding the US hydrogen market size to 22-41 Mt – i.e. doubling or even more than tripling current demand – even with prices of more than USD 1.00/kg H_2.

In June 2021, 17 MW of electrolysis for dedicated hydrogen production was operative in the United States,[34] with 1.4 GW of capacity in the project pipeline (300 MW under construction or with funding committed) and another 120 MW at earlier stages of

[34] The US DOE publishes regular updates on PEM electrolysers installed and under development in the United States.

development which could become online by 2030.[35] The US DOE estimates a potential deployment up to 13.5 GW based on company proposals and projections. These numbers fall short of what is needed to meet net zero goals.

US electrolysis capacity and hydrogen production from fossil fuels with CCUS in the Projects case and the Announced Pledges Scenario, 2030



Note: APS = Announced Pledges Scenario.
Source: IEA (2021), Hydrogen Projects Database.

In the Announced Pledges Scenario, 44 GW of electrolysis capacity is deployed by 2030. US progress on deploying capacity to produce hydrogen from fossil fuels with CCUS is accelerating in response to the 45Q tax credit, which rewards CCUS projects at rates of USD 50/t CO_2 for geological storage of CO_2 or USD 35/t CO_2 if used for enhanced oil recovery. In 2021, annual US production from fossil fuels with CCUS was 0.23 Mt H_2, around one-third of global production capacity.

The largest project currently under construction in the world (Wabash Valley Resources) is in the United States and expected to become operational in 2022, which could push production capacity to over 0.3 Mt. To align with the Announced Pledges Scenario, however, capacity should expand to more than 2.5 Mt by 2030.

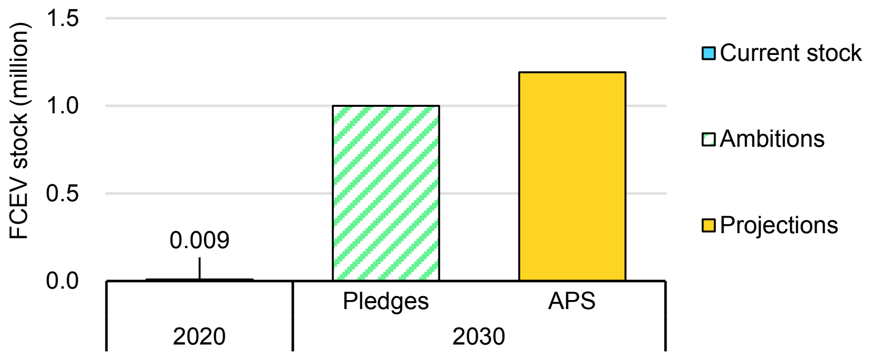
The United States led global deployment of FCEVs until 2020, when Korea pulled ahead. At the end of 2020, of the 9 200 FCEVs in the country, most were in California, which has been supporting deployment for almost a decade through the Clean Vehicle Rebate Project and by funding construction of hydrogen refuelling stations (HRSs).

In 2013, Assembly Bill 8 (AB8) required establishment of at least 100 HRSs; this target was doubled in 2018 to 200 HRSs by 2025. The main support mechanisms are grants (up to USD 115.7 million offered in GFO-19-602) and credits under the Low Carbon Fuel Standard Hydrogen Refuelling Infrastructure, which incentivise both

[35] Projects in the pipeline includes, in addition to projects already operational, projects currently under construction, that have reached final investment decision (FID) or that are undergoing feasibility studies. Projects for which there has just been an announcement or a cooperation agreement signed among stakeholders are considered projects at early stages of development.

renewable hydrogen (33-40%) and high-capacity HRSs. To support FCEV deployment, Air Liquide is building a 30-tpd renewable liquid hydrogen plant to supply HRS infrastructure in California.

FCEV deployment in the United States in the Announced Pledges Scenario, 2020-2030

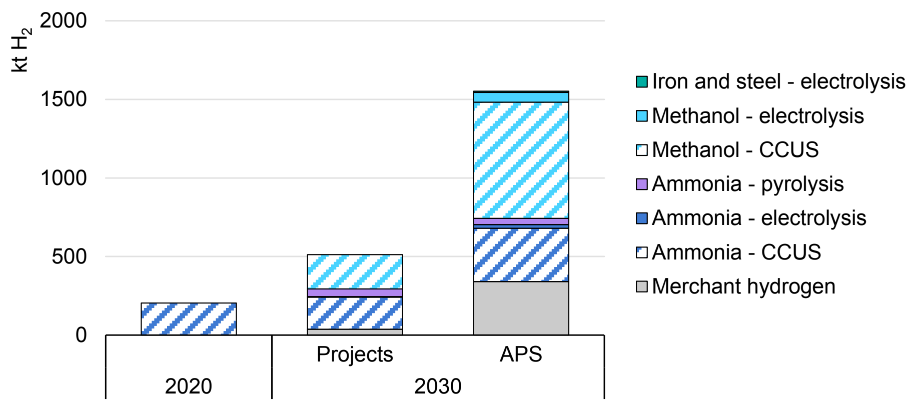


Notes: FCEV = fuel cell electric vehicle. APS = Announced Pledges Scenario. "Ambitions" refers to the California Fuel Cell Partnership target.
Source: AFC TCP.

In addition to FCEVs, a successful DOE programme has triggered commercialisation of hydrogen fuel cells for material handling equipment: in 2021, roughly 115 HRSs served over 40 000 fuel cell material handling vehicles. While the US government has not set an official federal target for FCEV deployment, the California Fuel Cell Partnership aims for 1 million FCEVs in the state by 2030. In the APS, national FCEV deployment slightly exceeds this target, reaching 1.1 million in 2030.

Opportunities to use low-carbon hydrogen in industry in the United States are mainly in the chemical sector. Low-carbon hydrogen is already produced in facilities incorporating CCUS, particularly for ammonia production. Since 2013, 1.7 Mt CO_2 have been captured every year at two fertiliser plants (Coffeyville and PCS Nitrogen), where captured CO_2 is used for EOR.

Low-carbon hydrogen demand in the US industry sector in the Announced Pledges Scenario, 2020-2030



Notes: APS = Announced Pledges Scenario. CCUS = carbon capture, utilisation and storage.
Source: IEA (2021), Hydrogen Projects Database.

A small number of projects for the production of hydrogen from fossil fuels with CCUS are currently in the pipeline in the United States. If all these projects become fully operational, the production capacity will meet 40% of the Announced Pledges requirement of 1.1 Mt H_2

produced from fossil fuels with CCUS in 2030. For electrolytic hydrogen use, current announced projects fall far short of the 2030 Announced Pledges level of around 85 kt H_2 for ammonia and methanol production – i.e. 25 times the capacity of the single ammonia project currently under development.

Interest is growing in the ways hydrogen can provide energy storage and be used as a means of generating on-demand electricity to balance the power grid as variable renewable generation increases. The Advanced Clean Energy Storage Project (ACES), under development in Utah by Mitsubishi Power Americas and Magnum Development, aims to pair 1 GW of electrolysers with large salt caverns to store 150 GWh of dispatchable energy. The hydrogen will be used in an 840-MW plant currently running on coal, which will initially be converted to run on natural gas and hydrogen blends, then eventually modified to operate on 100% hydrogen. While this is one of the largest project of its kind in the world, it would meet less than 12% of the nearly 1.4 Mt H_2 needed for electricity generation by 2030 (according to the Announced Pledges Scenario) to keep the United States on track with its net zero target for 2050.

The significant hydrogen uptake projected in the Announced Pledges Scenario, especially for new applications such as electricity generation and transport, would require rapid deployment of hydrogen infrastructure to facilitate delivery to end users. With more than 2 600 km of hydrogen pipelines currently in commercial operation, the United States accounts for over half of global hydrogen pipelines. Most are owned by merchant hydrogen producers and are located mainly in the Gulf Coast region where US refining capacity is concentrated.

The Hydrogen Strategy, published by the DOE in July 2020, considers blending an option to deliver pure hydrogen to downstream markets, using separation and purification technologies near the point of end-use. To help determine acceptable blending limits and material compatibility, in 2020 the DOE, together with industry and national laboratories, launched the HyBlend initiative.

In California, a first demonstration project using polymer-based distribution pipelines is expected to launch in 2021, with an initial hydrogen blend level of 1 vol% H_2, potentially rising to 20 vol% H_2. Meanwhile, Dominion Energy started a pilot project (spring 2021) to blend 5% hydrogen into a test gas distribution system. Kinder Morgan, one of North America's largest gas pipeline operators, estimates that hydrogen in 5-10% blends could be transported through natural gas transmission pipelines with little to no modification.

At present, three of the four hydrogen salt caverns storage sites operating globally are in the United States (all in Texas), including the world's largest facility in Spindletop (commissioned in 2016).

Japan: Announcement of a 2050 net zero target triggers new push for hydrogen technologies

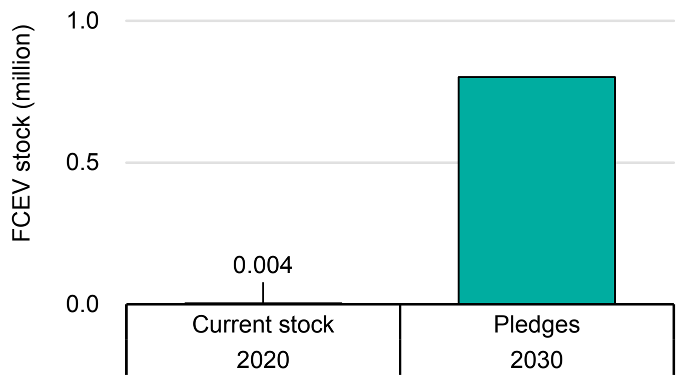
Hydrogen demand in Japan was close to 2 Mt H_2 in 2020. Refining is responsible for close to 90% of demand, with a small amount of domestic ammonia production making up the rest. Natural gas-based production accounts for more than 50% of the country's hydrogen supply, and another 45% is by-product hydrogen from refineries and the petrochemical industry and a small coal-based production meeting the remainder.

Japan has been spearheading efforts to adopt hydrogen technologies. It was the first country to release a hydrogen strategy (December 2017) and has been leading international co-operation since 2018 through its annual Hydrogen Energy Ministerial meetings. The country considers hydrogen technologies as practical options to decarbonise significant parts of its energy and industry sectors and to boost energy security.

Therefore, although Japan has yet to publish details on its plans to achieve the 2050 climate pledge announced by Prime Minister Suga (October 2020), hydrogen is likely to be an important part of its programme. The government's Green Growth Strategy (announced in June 2021) includes a target to expand hydrogen use to 3 Mt in 2030. To support this goal, the government announced a public investment plan of JPY 700 billion (~USD 6.6 billion) to develop hydrogen supply chains in Japan.

The plan includes up to JPY 70 billion (~USD 0.7 billion) for domestic hydrogen production capacity based on dedicated renewables and up to JPY 300 billion (~USD 2.8 billion) to develop international supply chains (using liquefied hydrogen and liquid organic hydrogen carriers) and to demonstrate co-firing or pure combustion of hydrogen in fossil-based electricity generation plants. In addition, JPY 330 billion (~USD 3.1 billion) have been allocated to innovation projects for hydrogen applications in aviation, shipping, steelmaking, ammonia production and CO_2 utilisation.

Current stock and 2030 target for FCEV deployment in Japan



Note: FCEV = fuel cell electric vehicle.
Source: AFC TCP, Strategic Roadmap for Hydrogen and Fuel Cells.

Japan has been a first mover in the use of hydrogen in transport, with Honda offering the first commercial FCEV in 2008. With around 5 600 FCEVs (including cars and buses) on the road in April 2021, Japan is the fourth-largest market in the world and has ambitious targets for FCEV deployment – 200 000 by 2025 and 800 000 by 2030. Toyota recently expanded fuel cell manufacturing capacity to 30 000 units/yr, though capacity will need to expand further if domestic original equipment manufacturers are to be relied upon to achieve government targets.

Japan has shown interest in using hydrogen to decarbonise energy demand in buildings. The ENE-FARM programme has subsidised installation of more than 350 000 micro-cogeneration[36] fuel cells, most fuelled by natural gas. Although ENE-FARM subsidies stopped in FY2019 for PEM fuel cells, more than 40 000 micro-cogeneration units were installed in 2020, similar to the number deployed annually while the programme was active. Subsidies remain in place for SOFCs until FY2020.

On the supply side, in 2020 a 10-MW solar-powered electrolysis project was inaugurated in Fukushima, the world's largest at the time. To date, Japanese stakeholders have not announced plans to deploy significant electrolysis capacity for dedicated hydrogen production; only some small projects (<5 MW) have been announced for upcoming years. This outlook may change following the government announcement of a budget of JPY 70 billion 70 (~USD 0.7 billion) to scale up and modularise electrolysers with the aim of decreasing manufacturing costs.

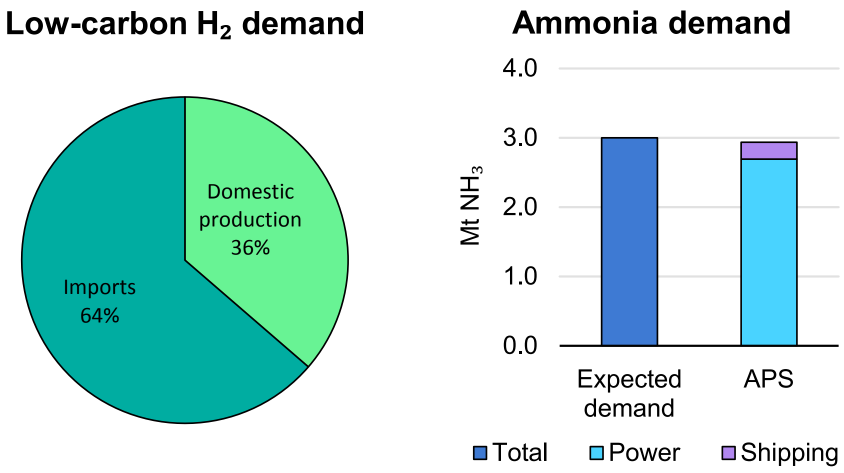
Regarding hydrogen production from fossil fuels with CCUS, the Tomakomai demonstration project was operational until 2019, and no projects for the near future have been announced. Low-carbon hydrogen production needs to be accelerated and international hydrogen supply chains must be developed to meet Japan's strategy target of 420 kt of low-carbon hydrogen by 2030. Japan is currently updating its strategy to align with its revised climate target, but it is likely that achieving the new targets will require substantial volumes of low-carbon hydrogen, with a significant portion having to be imported.

Japan has also targeted the use of ammonia as a fuel. In February 2021, the government released an Interim Report of the Public-Private Council on Fuel Ammonia Introduction highlighting its potential use in shipping and for co-firing in coal power plants to reduce their carbon intensity and avoid decommissioning them, as they are critical to Japan's electricity supply security. The concept was demonstrated at small scale by Chugoku Electric Power Corporation, and now JERA is scaling up the concept to demonstrate a 20% co-firing share of ammonia at a 1-GW coal-fired unit by 2024.

Using 100% ammonia in electricity generation is also gaining traction: Mitsubishi Power announced it is developing a 40-MW gas turbine able to run on ammonia, aiming to commercialise it in 2025. By 2030 in the Announced Pledges Scenario, Japan consumes close to 3 Mt NH_3 as fuel, mostly for co-firing in coal plants but also 0.25 Mt as fuel for maritime transport and. In addition, 0.7 Mt is used as feedstock in the chemical industry.

[36] Co-generation refers to the combined production of heat and power

Low-carbon hydrogen and fuel ammonia demand in Japan in the Announced Pledges Scenario, 2030



Notes: APS = Announced Pledges Scenario. "Expected demand" represents the proposal of the Interim Report of Public-Private Council on Fuel Ammonia Introduction.

Japan has been very active in developing international hydrogen trade: various projects are ongoing with Australia, Brunei, Indonesia, Saudi Arabia and the United Arab Emirates. Most noteworthy is the Hydrogen Energy Supply Chain (HESC) project, led by the Hydrogen Energy Supply-chain Technology Research Association (HySTRA), which aims to establish a hydrogen supply chain between Australia and Japan. As part of this project, in 2020 Kawasaki Heavy Industries presented its Suiso Frontier, the world's first liquefied hydrogen carrier; the first demonstration shipments will take place will take place during the first quarter of 2022. The Suiso Frontier has one tank with a capacity of 1 250 m^3, which can store 75 t H_2. A future commercial supply chain between Australia and Japan would require ships with much larger capacity, estimated by HESC project developers at four tanks, each with 40 000 m^3 of capacity. Ships of similar size to Suiso Frontier could be used for shorter distances.

Japan has also spearheaded development of international fuel ammonia trade. In September 2020, the world's first shipment of ammonia produced from fossil fuels with CCUS (40 t NH_3) took place between Saudi Arabia and Japan. Plus, the Japan Oil, Gas and Metals National Corporation (JOGMEC) recently launched several initiatives with partners in Japan and around the world. With the aim of supplying low-carbon ammonia to Japan, JOGMEC, Mitsubishi Corporation, the Bandung Institute of Technology and PT Panca Amara Utama (PAU) agreed (March 2021) to conduct a joint study on producing ammonia from natural gas with CCUS in a PAU plant in Central Sulawesi (Indonesia).

Additionally, in July 2021 JOGMEC, INPEX Corporation and JERA announced a joint study agreement with the Abu Dhabi National Oil Company (ADNOC) to explore the commercial potential of low-carbon ammonia production in the United Arab Emirates and to provide a platform for ADNOC and its partners to explore supplying Japanese utility companies. Also in July 2021, JOGMEC signed a joint research agreement with Woodside Energy, Marubeni Corporation, Hokuriku Electric Power Company and Kansai Electric Power to develop a supply chain from Australia to Japan for fuel ammonia produced from natural gas with CCUS.

European Union: EU Hydrogen Strategy set the foundation in 2020, but meeting net zero targets will require ambitious action in next decade

Close to 7 Mt H_2 were produced and used in the European Union in 2020. Refining (3.7 Mt H_2) and the chemicals sector (3.0 Mt H_2) were the main consumers of hydrogen, which was produced mainly from unabated natural gas (two-thirds of total production) and as a by-product in refineries and the petrochemical sector (30%).

In November 2018, the European Commission set out its vision for reaching net zero emissions by 2050, followed in March 2020 by the proposal for the first European Climate Law, which was adopted by the European Council in June 2021. To date, most decarbonisation efforts have focused on electricity generation, but adoption of the net zero target widened the scope beyond the power sector to include industry, transport, agriculture and heating in the built environment.

In turn, interest in hydrogen has grown exponentially, with launch of the EU Hydrogen Strategy (July 2020) and the European Clean Hydrogen Alliance (November 2020) being major milestones. The strategy emphasises use of hydrogen in industry and heavy transport as well as its balancing role in the integration of variable renewables (particularly offshore wind in the northwest region and solar PV in the south). The Alliance brings together industry, national and local public authorities, civil society and other stakeholders to implement the strategy.

On the supply side, electrolytic hydrogen from renewable sources is considered the main route for hydrogen production, although the role of other low-carbon technologies in the near term is recognised as the hydrogen market develops and scales up and the cost of electrolytic hydrogen decreases. Beyond decarbonising hydrogen production, the European Union sees electrolysis as a strategic opportunity to export technology: EU countries currently hold more than 60% of global electrolysis manufacturing capacity. With the aim of creating market rules for hydrogen deployment, the Hydrogen Strategy also announced a review of the legislative framework for gases.

The strategy envisages three phases for hydrogen adoption. The first phase (until 2024) focuses on scale-up, with an interim target of 6 GW of renewable energy-powered electrolysis to decarbonise current production capacities and trigger uptake in some new uses (e.g. heavy-duty transport). In the second phase (2025-2030), hydrogen should become an intrinsic part of an integrated energy system while renewable hydrogen becomes cost-competitive and reaches new applications (steelmaking or shipping). By 2030, 40 GW of renewable energy-powered electrolysis should be installed. In the third phase (post-2030), renewable hydrogen technologies should reach maturity and be deployed at large scale to reach all hard-to-decarbonise sectors.

In December 2020, the European Commission adopted a proposal to revise the EU rules on Trans-European Networks for Energy (the TEN-E Regulation) to end support for natural gas pipelines, instead including cross-border hydrogen networks as infrastructure eligible for EU support as Projects of Common Interest. The proposal covers both new and repurposed assets for dedicated hydrogen transport and large-scale electrolyser projects linked to cross-border energy networks.

A significant step taken by the European Commission in adopting low-carbon hydrogen technologies came from proposals to modify directives and regulations announced in July 2021 as part of the Fit for 55 package. If approved by the EU Council and the EU Parliament, these proposals will incorporate into EU legislation several targets for using hydrogen and hydrogen-based fuels in industry and transport, and for developing required infrastructure.

Some EU countries have also released national hydrogen strategies (the Czech Republic, France, Germany, Hungary, the Netherlands, Portugal, and Spain); others are under public consultation (Italy and Poland) or expected to be released soon (Austria). While focusing on each country's strengths, these strategies are very aligned with each other and with the EU Hydrogen Strategy in terms of sectors and technologies to prioritise. Practically all have deployment targets for electrolysis by 2030, amounting more than 20 GW by 2030 (with another 7 GW in the planned strategies of Italy and Poland).

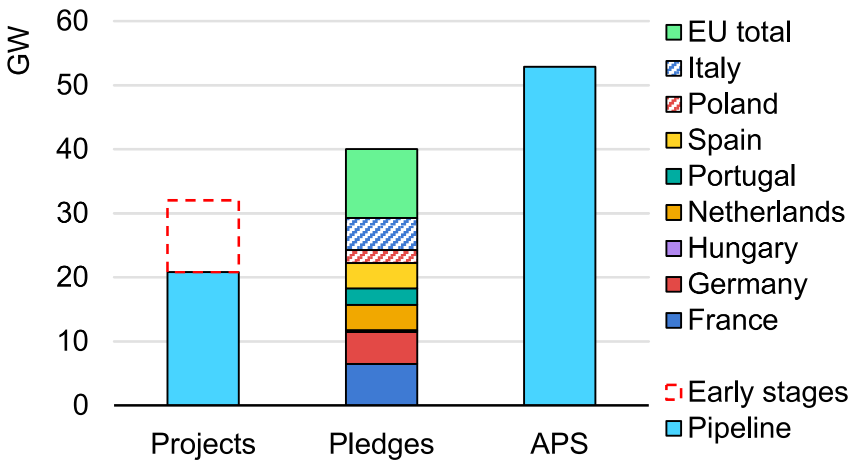
Hydrogen-related targets proposed by the European Commission in the Fit for 55 package

Proposal	Target
Renewable Energy Directive modification	50% renewable hydrogen consumption in industry by 2030
Renewable Energy Directive modification	At least 2.6% share of renewable fuels of non-biological origin in 2030*
ReFuelEU Aviation	0.7% share of synfuels in aviation by 2030 5% by 2035 8% by 2040 11% by 2045 28% by 2050
Regulation on deployment of alternative fuels infrastructure	1 HRS (>2 t H_2/day of capacity and 700-bar dispenser) every 150 km along major routes 1 HRS with liquid hydrogen every 450 km

* Renewable fuels of non-biological origin include hydrogen and hydrogen-based fuels produced from renewable electricity.

The European Union has registered progress in adopting hydrogen technologies. The Fuel Cells and Hydrogen Joint Undertaking (FCH JU) has played a fundamental role with its programmes to support research, innovation and demonstration. More than 140 MW of electrolysis for dedicated hydrogen production have been installed, accounting for more than 40% of global capacity. The strong signals sent by government strategies have created momentum for additional deployment, with the pipeline of projects currently under development accounting for more than 20 GW by 2030 (11 GW more from projects at very early stages of development), although initial assessment by the Clean Hydrogen Alliance suggests that total electrolysis capacity at different stages of development could be larger.

Electrolysis capacity deployment in the EU in 2030 in the Projects case and the Announced Pledges Scenario compared with national and EU targets



Note: APS = Announced Pledges Scenario.
Sources: IEA (2021), Hydrogen Projects Database; National Strategies, CEM H2I consultation.

Of the more than 20 GW in the pipeline, more than 1 GW is already under construction or has funding committed. While the current project slate may not meet the EU target, the number of projects is growing quickly and the gap is shrinking. However, both the current project pipeline and the EU target may fall short of the electrolysis capacity deployment needed to meet the EU pledge of net zero emissions by 2050. The Announced Pledges Scenario shows more than 50 GW of electrolysis deployed in EU countries by 2030.

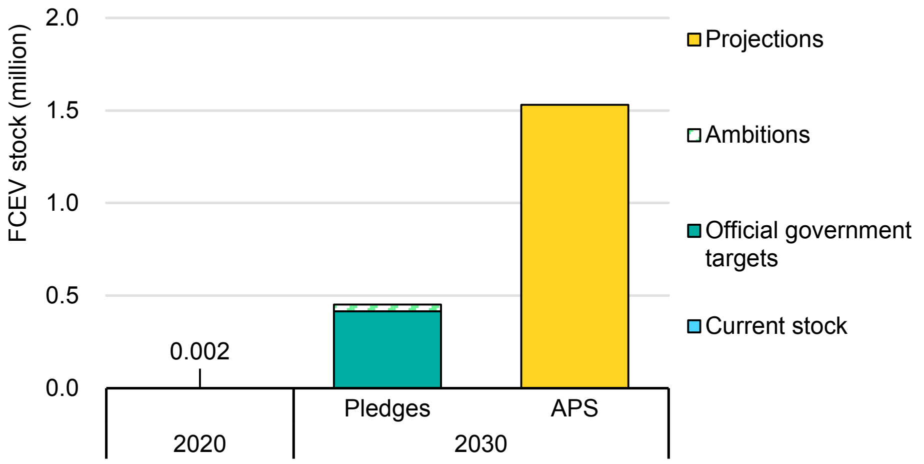
Progress in deploying hydrogen production from fossil fuels with CCUS has been slower, despite its envisaged near-term importance. Two projects are already operational in the European Union, although in both cases for hydrogen production from fossil fuels and CCU: the Shell gasification project at the Pernis refinery (the Netherlands) and Air Liquide's Port Jerome project (France).

The Netherlands is the most active country in developing hydrogen production from fossil fuels with CCUS. Through its SDE++ scheme, the Dutch government recently committed EUR 2 billion to fund Porthos, a project to develop CO_2 transport and storage infrastructure in the Port of Rotterdam, which will store 2.5 Mt CO_2 annually, with a significant share coming from hydrogen production.

The current pipeline of projects for producing hydrogen from fossil fuels with CCUS will more than meet EU net zero ambitions. While in the Announced Pledges Scenario 3 Mt CO_2 are captured from hydrogen production in the European Union by 2030, currently the project pipeline amounts to more than 7 Mt CO_2 captured (plus close to 3 Mt CO_2 more from projects at early stages of development), although this figure could be significantly lower. Several projects are large CCUS hubs that will involve activities beyond hydrogen production and, as such, it is difficult to estimate how much of the projected capture capacity would be linked to hydrogen production.

In transport, some 2 200 FCEVs were on the road in EU countries by the end of 2020 (mostly passenger cars) and around 165 HRSs were in operation. Germany has the largest number of both, but the Czech Republic, France, the Netherlands, Portugal and Spain have FCEV targets that, if achieved, would result in about 415 000 FCEVs by 2030. In the Announced Pledges Scenario, FCEV deployment reaches 1.5 million by this date.

FCEV deployment the European Union in the Announced Pledges Scenario, 2020-2030



Notes: FCEV = fuel cell electric vehicle. APS = Announced Pledges Scenario. FCEV ambitions include unpublished government targets from Italy and Slovakia.
Sources: AFC TCP; National Strategies; CEM H2I consultation.

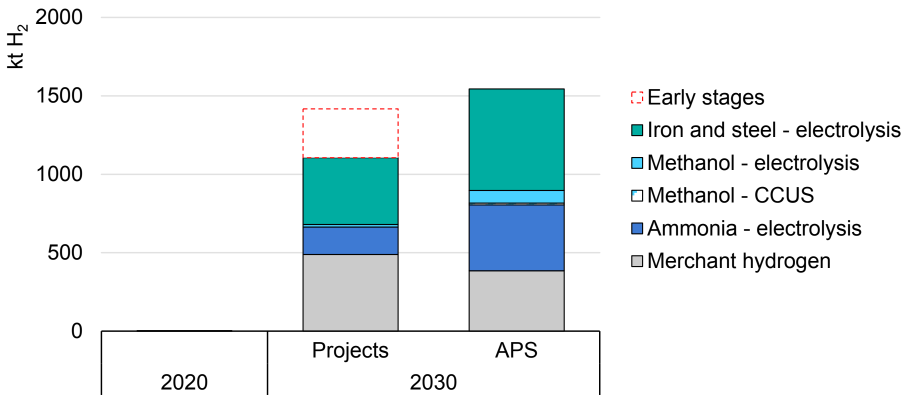
In the industry sector, EU stakeholders have been active in recent years and some significant developments are taking place. As part of the REFHYNE project, in July 2021 ITM and Shell put a 10- MW PEM electrolyser in the Rhineland Refinery (Germany) into operation. In steel manufacturing, Thyssenkrup has demonstrated using hydrogen to partially replace pulverised coal in one of the tuyeres of a blast furnace – and is working to extend this practice to other blast furnaces.

Since 2019, the H2FUTURE project has been feeding hydrogen produced in a 6 MW PEM electrolyser via the coke gas pipeline to a blast furnace of the steel works (Linz, Austria). Meanwhile, the HYBRIT project – the first attempt to produce steel from DRI using pure hydrogen – is currently at the pilot stage (4.5 MW of electrolysis capacity) but is expected to advance to a demonstration facility by 2025. Also in steel manufacturing, the largest SOEC electrolyser in the world (0.72 MW, manufactured by Sunfire) became operational in the GrinHy2.0 project.

In the chemical sector, Fertiberia and Iberdrola in Spain are building the world's largest demo project (20 MW) to produce electrolytic ammonia, expected to become operational at the end of 2021. The GreenLab Skive (Denmark) is building a 12 MW demonstrator for methanol production, to start operations in 2022. These proposed projects will not meet Announced Pledges goals for 2030, however.

Projects currently under development account for 1.1 Mt of low-carbon hydrogen use by 2030 (0.3 Mt more if early-stage projects are realised), whereas required Announced Pledges consumption is 10% higher.

Low-carbon hydrogen demand in EU industry in the Announced Pledges Scenario, 2020-2030



Notes: APS = Announced Pledges Scenario. CCUS = carbon capture, utilisation and storage.
Source: IEA (2021), Hydrogen Projects Database.

The first steps to develop hydrogen-specific infrastructure for delivery to end users have already been taken. Europe has more than 1 600 km of hydrogen pipelines, mostly owned and operated by industrial producers and users, but large-scale deployment of low-carbon hydrogen will require additional transmission and distribution systems.

A consortium of gas grid operators therefore presented a European Hydrogen Backbone (EHB) initiative proposal in 2020 (updated in 2021). Across 21 countries (including non-EU countries such as Switzerland and the United Kingdom), the EHB envisions 39 700 km of pipelines by 2040 – with 69% being repurposed natural gas networks and 31% newly built hydrogen pipelines. The first natural gas pipeline, 12 km with throughput capacity of 4 kt H_2/yr, has been converted and put into commercial service (November 2018) by Gasunie in the Netherlands.

In June 2021, Gasunie also announced that it had been asked by the State Secretary for Energy and Climate to develop a national infrastructure for hydrogen transport by 2027, of which 85% will be repurposed natural gas pipelines. In September 2021, the Dutch government announced an investment of EUR 750 million (as part of a wider EUR 6.8 billion package on climate measure) to convert parts of the existing gas network into hydrogen transport infrastructure. Furthermore, based on project submissions, the latest Ten-Year Network Development Plan of the European Network of Transmission System Operators for Gas assessed that roughly 1 100 km of gas pipelines could be converted to hydrogen by 2030, but FIDs have not yet been secured for these projects.

Several EU countries are also undertaking pilot blending projects, including France, Germany, the Netherlands and Portugal. In May 2021, the Government of Germany announced that 62 large-scale hydrogen projects, including pipeline transport, have been selected for further assessment for funding of up to EUR 8 billion under the Important Projects of Common European Interest (IPCEI) scheme.

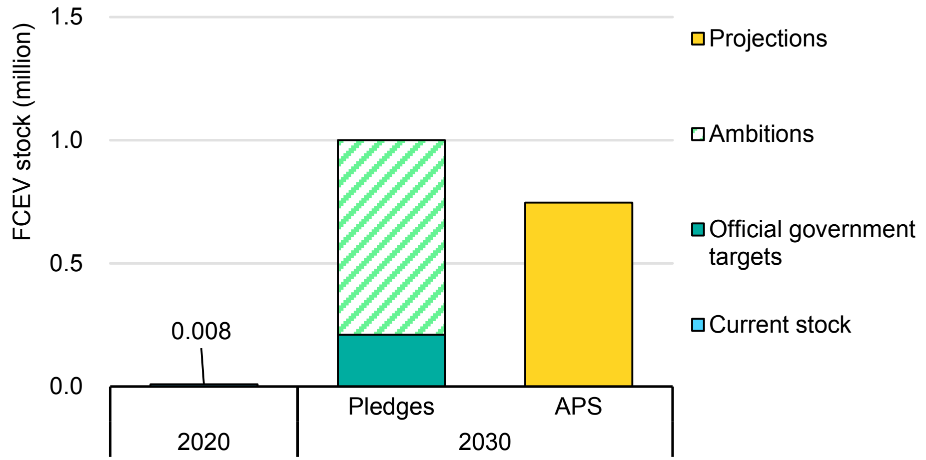
China: Hydrogen development focused on transport, but carbon-neutrality pledge will offer opportunities for other applications, particularly in industry

With annual consumption of more than 25 Mt, China is the world's largest hydrogen user, mainly in refining (9 Mt H_2) and the chemical sector (16.5 Mt H_2). This demand is met by domestic production based on fossil fuels, with coal accounting for 60% and natural gas for 25%. The remaining 15% is by-product hydrogen from refineries and the petrochemical industry.

In 2020, China announced its ambition to reach carbon neutrality by 2060. Hydrogen use will be important, especially in the country's vast industry sector, which accounts for 60% of final energy demand. Using hydrogen as an alternative to fossil fuels received attention even before China's net zero pledge, as it was seen as a means to address air quality concerns in cities.

As such, practically all developments around hydrogen adoption for new uses have focused on transport. Initial projects were based on using by-product hydrogen from coke ovens and petrochemical processes, which facilitated access to low-cost hydrogen in industrial hubs, and deploying fuel cell truck and bus fleets which maximise utilisation rates of HRSs. Thanks to these strategies and government support schemes, China has now the world's third-largest FCEV stock and leads in fuel cell truck and bus deployments. At the end of 2020, 8 400 FCEVs had been deployed, of which two-thirds were buses and one-third trucks.

FCEV deployment in China in the Announced Pledges Scenario, 2020-2030



Notes: FCEV = fuel cell electric vehicle. APS = Announced Pledges Scenario. Official government targets include city and provincial targets; ambitions refer to additional FCEV deployment needed to achieve the China Society of Automotive Engineers target.
Source: AFC TCP.

Although the government does not have an official target for FCEV adoption, the China Society of Automotive Engineers targets 1 million FCEVs by 2030. In response to China's recent pilot cities programme, which rewards city clusters for FCEV deployment and supply chain development, several city- and province-level targets have been set. Beijing and Shanghai each aim for 10 000 FCEVs by

2025, and Guangzhou envisions 100 000 by 2030. In the Announced Pledges Scenario, China's FCEV stock reaches 750 000 in 2030.

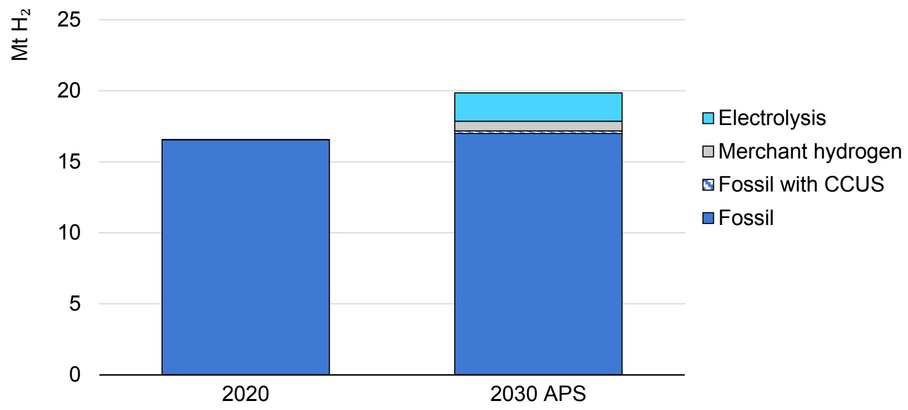
More recently, China has recognised how important hydrogen can be in transforming the energy system, and interest is growing beyond transport, particularly in industrial applications. China is the largest producer of methanol, ammonia and steel, three subsectors in which low-carbon hydrogen use could play a significant in the future. Beyond its traditional production and use in industry, low-carbon hydrogen adoption is in the early stages in China, with first steps for demonstrating new applications forthcoming.

In the chemical sector, Ningxia Baofeng Energy Group is building the world's largest electrolysis plant for dedicated production of hydrogen to provide some of the feedstock for making the methanol used in its coal-to-olefins project in Ningxia Province. The company has already installed a 30-MW electrolyser and intends to add 70 MW of electrolysis capacity by the end of 2021.

Baosteel, the country's largest steel producer, has pledged to reach net zero emissions by 2050, relying in part on developing hydrogen-based DRI production at scale by 2035. Meanwhile, Hebei Iron and Steel Group (HBIS), the second-largest producer, has taken the first step towards hydrogen steelmaking, developing a small but commercial-scale DRI project to blend 70% hydrogen (with 30% coke oven gas) for ironmaking.

These demonstration projects could lay the groundwork for low-carbon hydrogen adoption in China's industry sector. Although projects currently under development could result in 45 kt of low-carbon hydrogen production and use in industry by 2030, this is well short of the Announced Pledges projection of 2.2 Mt, produced mostly through electrolysis.

Industry hydrogen demand in China in the Announced Pledges Scenario, 2020-2030



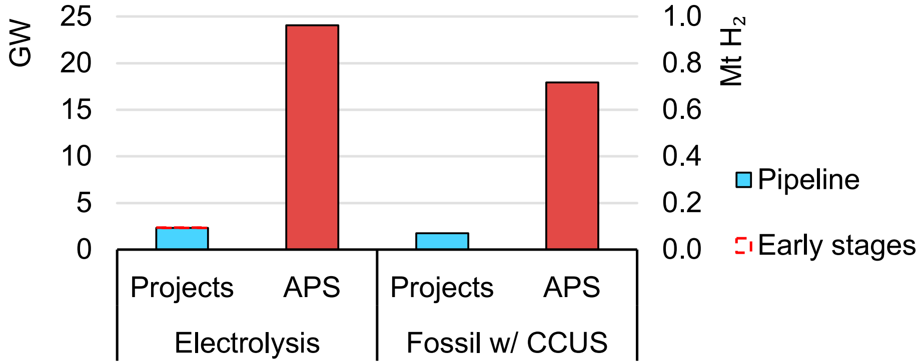
Notes: APS = Announced Pledges Scenario. CCUS = carbon capture, utilisation and storage.

China's greatest challenge is to decarbonise existing hydrogen production while deploying new production capacity to meet demand from new applications. At present, hydrogen production creates direct emissions of 475 Mt CO_2/yr.[37] Therefore, to stay on track with long-term climate ambitions, low-carbon hydrogen production technology deployment needs to accelerate in the next decade. By 2030 in the Announced Pledges Scenario, more than 20 GW of electrolysis is deployed in China, most of it in industrial facilities for producing methanol and ammonia. Plus, the first plant for manufacturing steel through DRI using hydrogen sequestered from coke oven gas should start operating by the end of 2021, and second-phase expansion and conversion towards electrolytic hydrogen should then begin.

Compared with other regions, China was slow to deploy electrolysis for dedicated hydrogen production; as a result, projects under development are insufficient to reach China's goals for 2030. However, several factors have triggered significant acceleration in the last two years:

- The cost of alkaline electrolysers in China is low – USD 750-1 300/kW including electrical equipment, gas treatment, plant balancing, and engineering, procurement and construction (EPC), with some sources reporting as low as USD 500/kW[38] – compared with the average of USD 1 400/kW in the rest of the world. Other factors, such as electrolyser reliability and durability, differ among regions and could strongly affect hydrogen production costs over a plant's lifetime.
- China has also deployed a huge amount of renewable energy generation capacity in recent years, especially in regions where potential is considerable but energy demand is fairly low. The resulting electricity grid congestion has forced some regional governments to limit the amount of power that can be loaded into transmission grids. Electrolysis can minimise curtailment and store energy for local use or for transport to regions with lower renewable energy potential and large energy needs.
- China accounts for one-third of global electrolyser manufacturing capacity. In response to anticipated domestic market growth, all major manufacturers have announced plans to expand their manufacturing capacity.

Electrolysis capacity and hydrogen production from fossil fuels with CCUS in China in the Projects case and the Announced Pledges Scenario, 2030



Notes: APS = Announced Pledges Scenario. CCUS = carbon capture, utilisation and storage.
Source: IEA (2021), Hydrogen Projects Database.

[37] This includes 115 Mt CO2 emitted through the use of hydrogen-derived products (e.g. urea and methanol) that capture carbon only temporarily.

[38] Based on CAPEX for the electrolyser system itself of USD 200/kW (China EV100, 2020; MOST, 2021). Including electrical equipment, gas treatment as well as EPC increases the overall CAPEX to USD 500/Kw.

The use of carbon capture to decarbonise current fossil fuel-based hydrogen production will also need to ramp up. This could be particularly beneficial for the chemical industry in China's north-western regions, where a very young fleet of plants currently uses coal to produce hydrogen-based ammonia and methanol. In the Announced Pledges Scenario, production capacity of 0.7 Mt H_2 in the chemical industry is retrofitted with CCUS by 2030.

Canada: Hydrogen to play a critical role in net zero ambitions and economic growth through exports

In 2020, Canada produced and used around 3 Mt H_2, almost equally split between refining and the industry sector. Around 80% of production is based on natural gas, and the remainder is by-product gas from refineries.

In December 2020, Canada released its strengthened climate plan, which lays the foundation to reach net zero emissions by 2050. Hydrogen and other clean fuels feature prominently in this plan. Also at the end of 2020, Canada released its Hydrogen Strategy with a call for action to promote investments and partnerships among national stakeholders, sub-national governments and indigenous organisations, as well as at the international level, to seize the economic and environmental opportunities that hydrogen can offer. The strategy shows that, in a net zero future, Canada's economy will be mobilised by two equally important pathways: clean power and clean fuels, with hydrogen making up to 30% of the energy mix.

The Canadian strategy addresses the role of hydrogen across a very wide range of end-use sectors, including industry, refining, transport, power and buildings. It also sees the variety of domestic energy resources available as a great opportunity to diversify the mix of technologies to produce hydrogen. This mix includes oil and gas reserves (coupled with CCUS) in Alberta, Saskatchewan, British Columbia and the East Coast, an 80% non-emitting power grid, nuclear capacity, and large renewable capacity. Based on these vast resources, Canada has an ambitious goal to become a major exporter of hydrogen-based fuels. As it is home to some of the sector's major technology developers (e.g. Ballard and Hydrogenics, recently acquired by Cummins), the potential to export hydrogen technologies is also high.

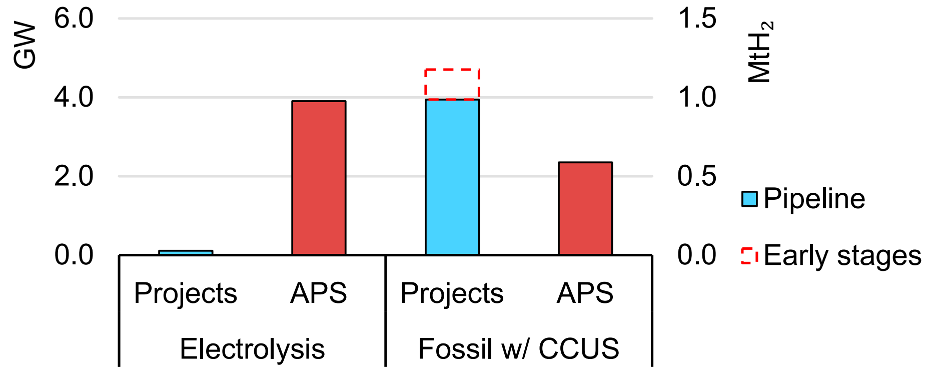
The Canadian government has already established a series of clean energy support programmes to enable the development of business cases for hydrogen technologies. In June 2021, Natural Resources Canada announced the Clean Fuels Fund, providing CAD 1.5 billion (~USD 1.1 billion) to help private investors with upfront capital costs to construct new clean fuel production capacity, including support for developing at least ten hydrogen projects. In addition, the Net zero Accelerator initiative will provide up to CAD 8 billion (~USD 6.0 billion) for projects that reduce domestic GHG emissions, including decarbonisation of large industrial emitters, fuel switching to hydrogen in industrial processes, and development of CCUS capacities for hydrogen production in heavy industries already using hydrogen.

Even before the national hydrogen strategy and related programmes were launched, Canadian stakeholders had been very active. With four operative projects capturing and storing around 3 Mt CO_2/yr, Canada is the second-largest producer of hydrogen from fossil fuels with CCUS. Another four projects are under development, aiming to capture an additional 5.0 Mt CO_2/yr (1.8 Mt CO_2/yr if early-stage projects are included). If all are realised, total hydrogen production from fossil fuels with CCUS could reach close to 1 Mt H_2/yr in 2030 (0.2 Mt H_2/yr with early-development projects) – around 70% higher than in the Announced Pledges Scenario.

However, projects under development aim to produce merchant hydrogen for diverse applications rather than decarbonise existing hydrogen production capacity in the chemical sector. Consequently, almost 200 kt H_2 (0.5 Mt H_2/yr with early-development projects) in fossil fuel with CCUS production capacity for industrial applications could be reached by 2030 – almost reaching the capacity in the Announced Pledges. Initiatives such as the Net zero Accelerator can speed deployment of low-carbon hydrogen capacity in industrial processes to better align with the Announced Pledges Scenario.

Concerning electrolysis, in January 2021 Air Liquide put into operation the world's largest PEM electrolysis plant at Bécancour. The project, which includes a 20 MW electrolyser running on hydropower, doubled the site's hydrogen production capacity. Currently, close to 100 MW of electrolysis projects are at different stages of development; if all are realised, total installed electrolysis capacity for dedicated hydrogen production could reach around 120 MW. In the Announced Pledges Scenario, electrolysis capacity in Canada reaches more than close to 4 GW by 2030, 40 times more than the capacity currently under development.

Electrolysis capacity and hydrogen production from fossil fuels with CCUS in Canada in the Projects case and the Announced Pledges Scenario, 2030



Notes: APS = Announced Pledges Scenario. CCUS = carbon capture, utilisation and storage.
Source: IEA (2021), Hydrogen Projects Database.

In the transport sector, Canada had a stock of around 130 FCEVs at the end of 2020. In the Announced Pledges Scenario, FCEV stock reaches close to 50 000 in 2030. Recent measures can facilitate this deployment: for instance, in December 2020 the government announced a new Clean Fuel Standard that will require liquid fuel suppliers to gradually reduce the carbon intensity of the fuels they produce and sell for use in Canada (final regulations will be published at the end of 2021). In June 2021, the government committed to a mandatory 100% ZEV sales target by 2035, followed by the announcement in August 2021 of a CAD 2.75 billion (~USD 2.1 billion) Zero Emission Transit Fund to support the purchase of zero emission public transit and school buses and associated infrastructure.

Other regions: Hydrogen momentum is building as more countries get on board

Africa

Of Africa's annual close to 3 Mt H_2 consumption, 70% is used in the chemical sector, mainly to produce nitrogen fertilisers that boost crop yields and replenish soil nutrients and are thus a critical component of food security across the continent. Without synthetic nitrogen fertilisers (together with other macro-nutrients), soil fertility would be significantly lower and land required for farming significantly higher.

Africa is one of the few places in the world where fertiliser use is projected to grow strongly in upcoming years, even as care is taken to apply it efficiently and judiciously, identifying the right fertiliser source, applying it at the right rate, at the right time and in the right place (CITE). In turn, ammonia production (the starting point of all synthetic nitrogen fertilisers) for existing agricultural and industrial uses increases 40% by 2030 in the Announced Pledges Scenario (see the IEA's forthcoming Ammonia Technology Roadmap).

Virtually all hydrogen production in Africa is currently based on fossil fuels, including the portion used to produce nitrogen fertilisers. The ability to produce hydrogen from renewables is therefore a great opportunity for African countries to replace fossil fuel-based production, which in many cases depends on imports. This is particularly important for landlocked countries that face additional challenges in distributing fertiliser and/or securing the natural gas needed to produce it.

Africa's potential to generate low-cost renewable electricity to produce low-carbon hydrogen is considerable. As electrolyser and renewable electricity generation costs continue to decline, cost parity with fossil fuel-based generation is a genuine prospect in the medium to long term in locations with the best renewable resources. In areas where the necessary transport and storage infrastructure is practical and scalable, low-cost natural gas equipped with CCUS is another option to produce low-carbon hydrogen for ammonia synthesis. Having an indigenous supply of nitrogen fertilisers made using low-carbon hydrogen would reduce CO_2 emissions from this energy-intensive industry while also boosting food security by reducing dependence on food imports.

Developing projects to produce renewable hydrogen for fertiliser manufacturing can also create high-quality jobs and spur economic growth, although project realisation will hinge on innovation and scale-up to close the cost gap with conventional production methods. Due to unfavourable economics, two large electrolysers (of 100 MW in Zimbabwe and 165 MW in Egypt) producing ammonia using renewable electricity from hydropower installations closed or switched to natural gas in the last decade, highlighting the challenges facing this technology option.

Similarly, ultra-low-cost electricity at a high capacity factor, or variable renewable electricity combined with hydrogen storage, is required for electrolysis-based ammonia production to become competitive with natural gas, even when equipped with CCUS. Given the practical ease and relatively low cost of shipping nitrogen fertiliser products (e.g. urea produced in the Middle East), cost reductions in the production process are required to make electrolysis a viable option for a price-sensitive market segment and region.

On-site production, storage and use of renewable hydrogen in mini-grids to generate electricity in remote areas is another hydrogen application attracting great interest. In fact, this concept has already been demonstrated. Hydrogen South Africa (HySA) has been operating a hydrogen-based mini-grid installed at a high school in Goedgevonden since April 2018, and Tiger Power is developing a project to power 3 000 rural households and businesses in Kyenjojo (Uganda). This application is cost-competitive with the traditional use of diesel for remote power generation, thus facilitating electricity access while decreasing CO_2 emissions.

Some countries in the region have taken the first steps to seize the opportunities hydrogen can offer. Morocco is leading the way with its Green Hydrogen Cluster, established by the government to promote collaboration among private and academic stakeholders to support the emerging renewable hydrogen sector. With the dual objectives of collaborating in technology development and positioning Morocco as a potential exporting hub, the government has been building international partnerships with countries such as Germany and Portugal.

Some activity is also well under way in South Africa, led predominantly by the private sector. Anglo American is building a 3.5-MW electrolyser at its mine in Mogalakwena to produce hydrogen on site to fuel a hydrogen-powered fuel cell electric haul truck. Expected to become operational in 2021, the project will be a first demonstrator to gain operational knowledge and experience, and thus support replication at other mines around the world.

Australia

In November 2019, Australia launched its National Hydrogen Strategy. It explores potential for clean hydrogen production, outlines a plan for quick scale-up and details the necessary co-ordinated actions for governments, industry and communities. As part of this plan, the government has invested over AUD 1.3 billion (~USD 1.0 billion) to accelerate domestic hydrogen industry growth. The strategy also highlights the significant opportunity offered by hydrogen exports, which the government is fostering by developing international partnerships with Singapore, Germany, Japan, Korea and, more recently, the United Kingdom.

Current hydrogen demand in Australia is very small, practically all used in refining and ammonia production; moreover, growth in domestic demand is generally seen as limited. However, the country has tremendous potential to affordably produce low-carbon hydrogen, which can decarbonise production for both domestic use and export. Recognising this opportunity, the government has invested in seven hydrogen hubs that centralise users geographically, thereby minimising infrastructure costs.

Australia's potential to produce hydrogen from renewables is considerable. Currently, nine projects with a capacity >1 GW are under development or at early stages. These include some of the world's largest projects: the Western Green Energy Hub (20 Mt NH_3/yr, equivalent to >20 GW of electrolysis capacity); the Asian Renewable Energy Hub (14 GW); HyEnergy Zero Carbon Hydrogen (8 GW); and the Murchison Project (5 GW). If all projects under development are deployed, electrolysis capacity in Australia will reach nearly 20 GW by 2030 (33 GW including early-stage ones), the vast majority aiming to export hydrogen and ammonia. However, the Asian Renewable Energy Hub recently encountered government pushback; in June 2021 its application was rejected due to potential adverse impacts on habitats and native species.

Australia has also significant fossil fuel resources, particularly Victoria's brown coal reserves. Combined with CCUS, they could be another energy source for low-carbon hydrogen production. The first facility for producing hydrogen from coal started operation (in the Latrobe Valley) in March 2021 as part of the HESC project lead by HySTRA. The facility is not incorporating CCUS in its first phase, but it will be retrofitted with CCUS capabilities by 2030, subject to successful demonstration of the economic viability of transporting liquid hydrogen from Australia to Kobe in Japan.

India

More than 7 Mt H_2 was used in India in 2020, with 45% used for refining, 35% for chemicals and almost 20% for iron and steel. India is the world's largest producer of steel using the DRI route, consuming one-quarter of global hydrogen demand for this end use. Practically all hydrogen demand is met through domestic production based on fossil fuels, with natural gas accounting for three-quarters, coal for more than 15% and by-product from refineries making up the rest.

Irrespective of the scenario context, hydrogen use in India is expected to rise substantially in the next decade as population growth and greater prosperity necessitate increased food production (requiring ammonia) and new infrastructure (requiring steel). In the Announced Pledges Scenario, hydrogen demand grows to close to 11 Mt H_2 by 2030, with DRI-based steelmaking accounting for around 30% of this increase.

India's enormous potential to expand hydrogen demand and its considerable renewable energy possibilities offer an extraordinary opportunity to decarbonise the industry sector while also reducing fossil fuel import dependency. If electrolysis were deployed at scale and the potential for cost reductions materialised, India could be one of the regions with the lowest costs for producing hydrogen from renewables.

As early as 2030, hydrogen production from renewables could cost just USD 1.4-3.7/kg H_2, competitive with production through unabated fossil fuel methods. Low production costs for renewable hydrogen could enable the export of low-carbon hydrogen and hydrogen-based fuels, particularly to other Asia-Pacific economies that are likely to require imports to meet national hydrogen demand (e.g. Japan and Korea).

The Indian government has taken the first steps to seize the energy sector decarbonisation opportunities hydrogen can offer. Early in 2021, it launched the National Hydrogen Mission (NHM) to articulate the government's vision, intent and direction for hydrogen and to outline a strategy. The NHM will also explore policy action to support the use of hydrogen as an energy vector and develop India into a global hub for hydrogen and fuel cell technology manufacturing.

The first policy actions are under way, with the government having announced the adoption of auctions (in 2021) for producing hydrogen from renewables and mandatory quotas for using renewable hydrogen in refining and ammonia production. According to the proposal, starting in 2023/24 refineries will have to meet 10% of their hydrogen demand with renewable hydrogen, increasing to 25% in the following five years. Fertiliser producers will need to meet 5% of demand with renewable hydrogen in 2023/24, increasing to 20%. This proposal is expected to be extended to the steel industry in the near future.

The Indian government also announced plans for new developments in gas grid infrastructure, connecting major demand centres with ports to help the latter become major import/export hubs. The industry sector has also become involved, with some major companies (e.g. Adani, Arcelor Mittal, the Indian Oil Corporation, NTPC, Reliance Industries and the Solar Energy Corporation of India) announcing ambitious plans to develop projects for low-carbon hydrogen production.

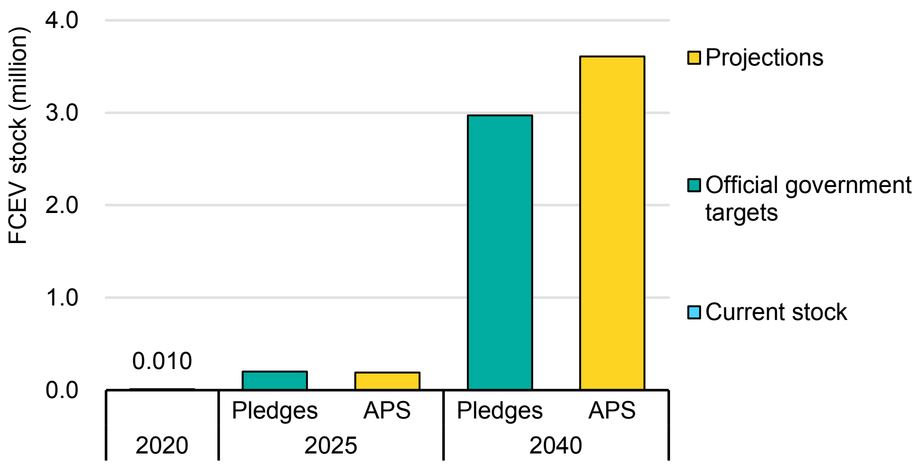
Korea

More than 1.8 Mt H_2 were produced and used in Korea in 2020, with practically all demand coming from refining and petrochemical processes. Around 60% of the hydrogen used is obtained as by-product from various sources, with the remaining 40% produced from natural gas. Korea is among the most active countries in adopting hydrogen technologies. In 2019 the government launched its Hydrogen Economy Roadmap, which outlines a vision for the role of hydrogen in the energy sector. The roadmap highlights two priorities: creation of a hydrogen market; and the development of hydrogen-utilising industries to create the world's largest market for fuel cells for transport and electricity generation.

In transport, Korea became the leader in FCEV deployment in 2020, with over 10 000 FCEVs on the road. In its 2020 New Deal, the government increased the 2025 FCEV target from 100 000 (set in the 2019 hydrogen roadmap) to 200 000, and for 2040 it is targeting close to 3 million FCEVs, including 2.9 million domestically manufactured fuel cell cars, 30 000 fuel cell trucks and 40 000 fuel cell buses.

Furthermore, interest in using hydrogen in transport extends beyond decarbonising domestic transport. As fuel cell development is also considered an important technology export opportunity, the roadmap established targets for exporting 3.3 million FCEVs by 2040. Hyundai's announced fuel cell manufacturing capacity of 500 000 units/yr in 2030 largely aligns with the production target of 6.2 million fuel cell cars by 2040.

FCEV deployment in Korea in the Announced Pledges Scenario, 2020-2040



Notes: FCEV = fuel cell electric vehicle. APS = Announced Pledges Scenario. Source: AFC TCP; Korea 2020 New Deal; Hydrogen Economy Roadmap.

Regarding stationary fuel cells, Korea currently has 620 MW of installed capacity – almost double what it had at the end of 2018, according to its Hydrogen Economy Roadmap. Most of this capacity is used for electricity generation (605 MW), but a small fraction (15 MW) is used in buildings. Practically all this capacity is fuelled by natural gas, but stakeholders are taking steps to operate fuel cells with 100% hydrogen.

By 2040 in the Announced Pledges Scenario, Korea consumes 1.9 Mt H_2 to generate 33 TWh of power. This will require an installed capacity of 18 GW – far more than the Korean government's target of 8 GW. This 18 GW also includes other hydrogen technologies for electricity generation, such as co-firing hydrogen with natural gas in gas turbines. The Korean government also considers stationary fuel cells a technology export opportunity, so the Hydrogen Economy Roadmap targets 7 GW of stationary fuel cell exports by 2040.

Korea is also giving considerable attention to producing low-carbon hydrogen and developing hydrogen infrastructure. So far, hydrogen demand for fuel cell applications has been met with by-product hydrogen or unabated natural gas-based production. In the transition to 2040, the Hydrogen Economy Roadmap prescribes greater hydrogen production from water electrolysis and from natural gas with CCUS, and more hydrogen imports.

The first projects to develop low-carbon hydrogen production are already under way: in 2021, SK E&S and Hyundai Oilbank announced plans to develop two projects for hydrogen production from natural gas with CCUS, for a combined production capacity of 350 kt H_2/yr. Plus, the Korea National Oil Corporation and Korea East-West Power have announced the potential incorporation of a 100-MW electrolysis plant into the Donghae 1 offshore wind project, expected to be completed by 2025. On the infrastructure side, Linde and Hyosung partnered in 2021 to build Asia's largest hydrogen liquefaction plant (30 t H_2/day) to supply hydrogen for use in transport.

Latin America

Latin American countries consumed 3.5 Mt H_2 in 2020, of which 2.5 Mt H_2 was used in industry and the rest in refining. The vast majority of the production (90%) was based on natural gas, with by-product hydrogen from refineries making up the rest.

A combination of factors has spurred increased interest in hydrogen in the region. The major economies (Argentina, Brazil, Chile, Colombia and Mexico) already produce large volumes from unabated fossil fuels for use in oil refineries and in the chemical and iron and steel industries, and Trinidad and Tobago is among the world's largest producers of ammonia and methanol.

Latin America also has one of the world's highest shares of renewables in electricity generation, with Costa Rica, Paraguay and Uruguay producing practically all their electricity from renewables. Plus, the region has significant oil and gas resources, particularly in Venezuela, Brazil and Mexico.

This combination of factors can create complementarities and synergies across the region. Establishing effective co-operation among the countries could therefore help the region meet the challenges of adopting hydrogen as a clean fuel while generating economic growth.

Chile has taken the lead in announcing hydrogen developments. Having enormous renewable energy potential – well exceeding its energy demand – it can produce renewable hydrogen at costs that are among the lowest in the world. The government published its Green Hydrogen Strategy in November 2020 with the ambition of becoming the top destination in Latin America for renewable hydrogen investment by 2025 and one of the world's largest exporters of hydrogen-based fuels by 2030. The strategy also targets 25 GW of electrolysis operational or under development by 2030.

Chile's private sector has responded to the government's call for action by launching some major initiatives. For instance, the Haru Oni project, led by HIF, aims to demonstrate synthetic methanol production using hydrogen produced by wind-powered electrolysis in Magallanes. The first phase is expected to be operational by 2022, and if successfully demonstrated, the project will be expanded in subsequent phases to produce 550 million litres of synthetic fuels annually by 2026 (with 2 GW of installed electrolysis capacity). The objective is to export these hydrogen-based fuels.

Meanwhile, in 2020 ENAEX and Engie announced the HyEx project to deploy up to 780 MW of electrolysis by 2030 to produce ammonia in Antofagasta, starting with a pilot of 50 MW of electrolyser capacity to be implemented by 2024. ENAEX, a company that produces explosives for the mining sector, imports 350 kt of fossil fuel-based ammonia annually, subject to high price volatility. The company therefore aims to secure and internalise its ammonia feedstock supply while also reducing its CO_2 emissions.

Chile's national hydrogen strategy also highlights the usefulness of electrolysis in decarbonising existing uses (in the chemical industry and refining), and especially heavy road transport. In a noteworthy activity in the mining sector, a major contributor to the economy, stakeholders are developing as many as 13 different initiatives for using hydrogen in mining, particularly for trucks used at mines.

The release of the Chile's strategy stimulated hydrogen-related policy discussions across the region. In Argentina, an inter-ministerial group was created to develop a hydrogen roadmap and update existing laws to promote hydrogen, and in February 2021, Brazil's Energy Research Office (EPE) released its first technical document laying the foundation for a national hydrogen strategy. Colombia announced the launch of its national strategy at the end of September 2021 and the governments of Panama, Paraguay, Trinidad and Tobago, and Uruguay are also developing hydrogen strategies and roadmaps.

In turn, the private sector is taking action to leverage hydrogen opportunities. For example, in early 2021 Energix announced the Base One project to deploy around 3.4 GW of electrolysis capacity powered by renewable energy (at Ceará, north-eastern Brazil). All hydrogen produced will be exported from the Port of Pecem (a founding member of the Global Ports Hydrogen Coalition).

In 2017, Costa Rica was the first country in the region to deploy a fuel cell bus and four FCEVs. The government, in collaboration with the private sector, presented an institutional plan to facilitate the use of hydrogen in transport in 2018 and is currently developing a national strategy. Meanwhile, Panama's strategic location at the crossroads of major shipping routes makes it a global hub for maritime transport and a centre for regional trade. While current hydrogen production and use are very limited, in 2021 the government presented its vision for Panama to become a logistics and distribution centre for low-carbon hydrogen-based fuels, initially focusing on the maritime shipping industry.

More details about hydrogen's status and opportunities in Latin America can be found in the IEA's August 2021 report Hydrogen in Latin America.

Middle East

Countries in the Middle East consumed around 11 Mt H_2 in 2020, using close to 4 Mt H_2 in refining, more than 5 Mt H_2 in the chemical industry and 1.5 Mt H_2 in steel production. Natural gas accounts for close to 90% of production, with by-product hydrogen from refineries making up the remainder.

The Middle Eastern region has a formidable combination of oil and gas reserves and tremendous renewable energy potential (particularly solar) that can enable low-carbon hydrogen production at significantly lower cost than in most parts of the world. Plus, Middle Eastern countries have considerable experience in exporting LNG. Owing to all these factors, the countries aim to become major international suppliers of low-carbon hydrogen. Oman, Saudi Arabia and the United Arab Emirates have been the most active to date, having several projects under development and participating in various international co-operations.

In Saudi Arabia, Air Products, Acwa Power and Neom signed an agreement in 2020 to develop a USD 5-billion project to produce 650 t H_2/day using electrolysis powered by 4 GW of solar PV and wind. Part of the hydrogen produced will be transformed into ammonia for export to Air Products clients globally. The project has already reached FID and the design and early work are now under way, with the expectation that it will be operational in 2025. Thyssenkrupp and Haldor Topsoe are involved as technology providers.

Saudi Arabia has been quite active in the international sphere, seeking to develop potential supply chains through which it could become a major exporter, particularly to Europe and Japan. In September 2020, Saudi Aramco, the Institute of Energy Economics, Japan and SABIC successfully carried out the world's first shipment of ammonia produced from fossil fuels with CCUS, shipping 40 t of ammonia from Saudi Arabia to Japan for use in electricity generation while captured CO_2 was used in EOR and chemical production in Saudi Arabia. In March 2021, the Saudi government signed a collaboration agreement with Germany to lay the groundwork for developing an international hydrogen (or ammonia) supply chain.

In 2020, DEME announced the first initiative to develop a large-scale electrolysis plant (250-500 MW) in Oman. The number and size of projects announced has since grown significantly. For instance, a USD 2.5-billion collaboration between ACME Solar and the Oman Company for the Development of Special Economic Zone will produce 2 400 t/day of green ammonia. Furthermore, in May 2021 an international consortium of companies announced plans to develop the Green Fuels Mega Project, a 14-GW electrolysis project powered by 25 GW of wind and solar PV, with construction planned to start in 2028 and full operations expected by 2038. As most of these projects aim to produce low-carbon hydrogen or ammonia for export, the Port of Duqm (a founding member of the Global Ports Hydrogen Coalition) is a cornerstone of the initiatives being developed in Oman.

In the United Arab Emirates, Emirates Steel has been operating the Al Reyadah CCUS Project since 2016, capturing 800 kt CO_2/yr from DRI-based steel production. In 2021, DEWA and Siemens inaugurated Expo 2020 Dubai (delayed because of the Covid-19 pandemic), the region's first renewable energy-powered electrolysis project.

In addition, by signing an agreement with Japan to collaborate on hydrogen production technologies and create an international supply chain, the Emirates have taken the first steps to becoming hydrogen exporters. ADNOC announced a joint study agreement with two Japanese companies (INPEX, JERA) and a government agency (JOGMEC) to investigate the potential of producing ammonia from fossil fuels with CCUS to supply Japanese utilities. ADNOC is already developing a large-scale low-carbon ammonia production facility (capacity of 1 Mt NH_3/yr) at the TA'ZIZ Industrial Chemicals Zone and exploring opportunities to commercialise this product.

Kuwait and Qatar have also taken the first steps in developing their hydrogen strategies, in preparation to capture opportunities to exploit their natural resources to produce hydrogen.

Policy recommendations

Attaining climate goals will require ambitious, decisive action in the next decade

The IEA's Net zero by 2050 roadmap shows that achieving net zero targets will require immediate action to make the 2020s the decade of clean energy expansion through massive deployment of available low-carbon technologies and accelerated innovation of those still under development. Hydrogen technologies are a key example, with a considerably higher pace of progress and deployment required from now until 2030. The three overarching goals are to significantly expand hydrogen use while bringing new technologies onto the market; make hydrogen production much cleaner (i.e. shift away from unabated fossil fuel-based routes); and reduce the costs of technologies for hydrogen production and use.

To inform decision-making, this report presents a series of milestones that need to be reached by 2030 to unlock hydrogen's potential to address climate change. These markers cover the entire hydrogen value chain, including its production, infrastructure requirements, transformation into other fuels and end uses. Ultimately, the milestones are a call for action to governments. The implementation of policies to support their achievement can help build confidence among investors, industry, citizens and other countries, in turn prompting collaboration to trigger uptake of hydrogen as a new energy vector.

Key milestones to stay on track with the Net zero Emissions scenarios by 2030

	2020	NZE 2030	Development status
Total H_2 demand ($Mt\ H_2$)	90	212	-
Electrolysis capacity (GW)	0.3	850	Mature
CO_2 captured and stored in H_2 production ($Mt\ CO_2$)	10	410	Mature
Total road FCEVs (million vehicles)	0.035	15.3	Market scale-up
HRSs (1 000s of stations)	0.54	18	Market scale-up
NH_3 demand in shipping ($Mt\ NH_3$)	0	47	Demonstration
H_2 demand in electricity generation ($Mt\ H_2$)	0	43	Demonstration
Low carbon H_2 demand in DRI ($Mt\ H_2$)	0.1	5.7	Demonstration
Synfuel demand in aviation (mb/y)	0	38	Prototype
Export terminals (number of terminals)	0	60	Prototype

Near-term policy recommendations to enable the required transformation

To achieve the Net zero Emissions milestones, governments must take a lead role in facilitating the clean energy transition by establishing policy frameworks that stimulate integrated action. In The Future of Hydrogen, the IEA identified a series of recommendations for near-term policy action. Here, this Global Hydrogen Review expands on these policies and explains how they can facilitate attainment of the milestones.

Policies should centre on the need to:

- Develop strategies and roadmaps on hydrogen's role in energy systems.
- Create strong incentives for using low-carbon hydrogen to displace fossil fuels.
- Mobilise investment in production assets, infrastructure and factories.
- Provide strong innovation support to ensure critical technologies reach commercialisation quickly.
- Establish appropriate certification, standardisation and regulation regimes.

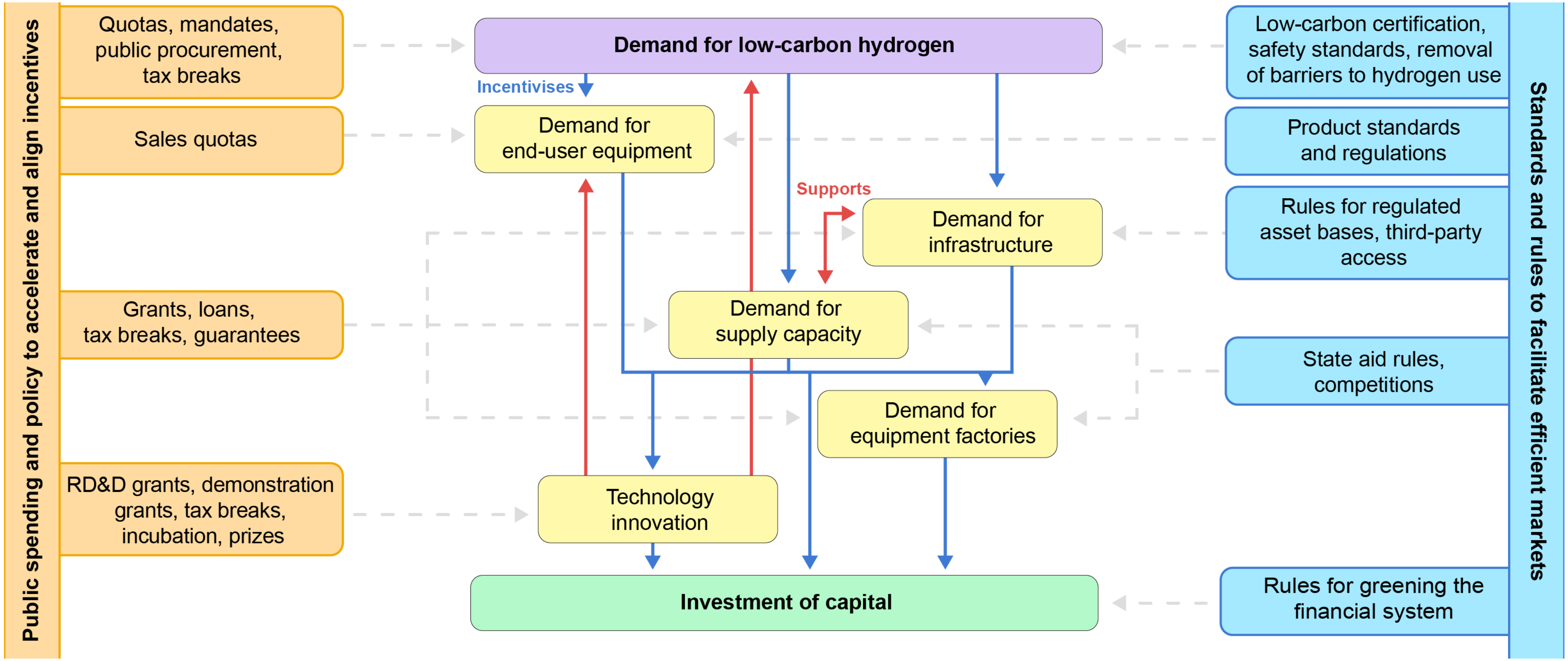
As all these policies are interconnected, implementation of one will impact the potential outcomes of the others. Some are natural first steps, such as defining the role of hydrogen in national energy strategies. However, it is unlikely this role can be realised without sufficient stimulus measures to create demand and mobilise investments for the infrastructure needed to connect hydrogen producers and users in the initial adoption stages. Developing such infrastructure requires planning among diverse stakeholders, with local authorities playing a key role as co-ordinators. Co-ordination of efforts can be facilitated if the roles of the different stakeholders are clearly and properly defined in hydrogen strategies and roadmaps.

In turn, the extent to which demand can be created will depend on increased effort in two main areas: support for innovation to ensure technologies are developed and become competitive; and establishment of standards and certification schemes to ensure the interoperability of these technologies globally and provide certainty to end users about the products they are acquiring on the market. Market development will also depend on adequate regulation to guarantee fair competition.

Ultimately, these features all work together like gears in one system: they all need to be in place and function in a co-ordinated fashion to ensure the effective adoption of hydrogen technologies at the required levels, within the next decade. The success of these policies will also depend on other measures, such as the development of training programmes to create a skilled workforce, ready to deploy and operate novel hydrogen technologies.

In the long term, consumer demand will drive investment in low-carbon hydrogen value chains. In the short term, however, it is up to policymakers to pull various levers to attract capital to the right places to create such demand.

How policy and regulatory interventions can amplify and steer incentives across hydrogen value chains



Develop strategies and roadmaps on hydrogen's role in energy systems

National hydrogen strategies and roadmaps with concrete milestones for implementation and specific targets for producing and using hydrogen are essential to signal government commitment to expanding hydrogen supply and use. Ideally, they should be part of wider government strategies to achieve climate targets, thereby anchoring hydrogen as part of the expected energy future. Developing strategies and roadmaps is thus critical to build stakeholder confidence in the potential marketplace of low-carbon hydrogen and related technologies.

More and more countries have taken the vital first step of establishing national strategies in the last couple of years, creating momentum for the hydrogen industry and triggering new investments. Nevertheless, IEA analysis of stated targets detects a widening supply-demand gap due to strong policy focus on expanding low-carbon hydrogen supplies and relatively little action designed to increase market demand.

Clearly, emphasising the "push" for low-carbon hydrogen by increasing production capacity without creating sufficient market "pull" for the end product can create imbalances – and even bottlenecks – in the hydrogen value chain. Lack of demand can impede the emergence of supply projects, making it more difficult to achieve government targets for low-carbon hydrogen production.

Scenario analysis in this report suggests a growing need for more ambition to boost demand for low-carbon hydrogen, to both replace current demand for fossil fuel-based hydrogen (in refining and industry) and create demand for new applications such as heavy-duty transport, energy storage, new industrial applications, shipping and aviation.

Specific targets must therefore be adopted for using low-carbon hydrogen in existing applications and for deploying new hydrogen applications within this decade. Endorsing these aims at the national level can facilitate co-ordinated global action to achieve the milestones for 2030 proposed in this report.

Including hydrogen demand and production as well as hydrogen technology deployment in national energy statistics and reporting is also advisable. Tracking demand by sector, production through different routes, and other parameters related to hydrogen technology deployment (e.g. the number of HRSs, installed electrolysis capacity and the number of FCEVs on the roads by vehicle type) is critical to assess progress in meeting strategy and roadmap targets.

The IEA is ready to apply its analytical capabilities to help governments around the world define the role hydrogen can play in meet their climate goals and advance their strategies and roadmapping efforts.

Create strong incentives for using low-carbon hydrogen to displace fossil fuels

Demand creation is a key lever to stimulate adoption of hydrogen as a clean energy vector. However, using low-carbon hydrogen is more costly than employing incumbent technologies, whether one compares with fossil-based hydrogen in traditional uses or the combustion of fossil fuels in potential new hydrogen applications.

Although an increasing number of countries now impose carbon pricing or taxation, current carbon prices are not high enough to close the cost gap between low-carbon hydrogen and fossil-based alternatives. Carbon prices are expected to rise in some countries and jurisdictions (e.g. Canada, Norway and the European Union), but this can take many years and, while helpful, may not drive transformation at the speed required.

To help industry de-risk investments and improve the bankability of projects, governments should design policy frameworks and financial support schemes that are transparent and predictable. Three key policy instruments already show strong potential for this purpose:

- Carbon contracts for difference. Already proposed by the European Union and Germany, this is a new policy instrument to bridge the gap between current carbon prices and the price needed to trigger fuel switching in target industries (e.g. refining, iron and steel, and chemicals). Using auctions to support the most competitive projects can be an effective way to hasten low-carbon hydrogen adoption (particularly for traditional refining and industrial applications).
- Mandates/quotas. Gradually rising mandatory quotas for low-carbon technologies, both for existing hydrogen uses (e.g. refineries and fertiliser production) and new-use sectors, can be a powerful instrument to stimulate the adoption of low-carbon hydrogen-based fuels in some jurisdictions (e.g. California's Zero-Emission Vehicle [ZEV] mandate). Such demand-pull policies can strengthen the business cases of hydrogen projects without expending significant public funds. For example, demand for low-carbon hydrogen can be stimulated through mandates for ZEVs; blending quotas for low-carbon gases in natural gas grids or low-carbon fuels in power generation; and mandates for synfuel use in aviation. Mandates can also be reinforced by relevant disincentives, such as a ban on the sale of internal combustion engine vehicles; sunset clauses for conventional industrial equipment; and regulations for deploying combustion equipment (e.g. domestic appliances and industrial boilers and turbines) compatible with low-carbon fuels.
- Public procurement. All levels of government and public agencies can help create demand for low-carbon hydrogen by modifying public procurement contracts to require its use for public transport, taxi services, waste collection, trucks, ferries and barges, and by stipulating the use of low-carbon steel and cement in infrastructure projects. For example, the Norwegian government recently decided that the largest ferry connection in the country (Bodø-Værøy-Røst-Moskenes) should be fuelled by hydrogen. In some countries, governments have direct influence on the strategies and investment allocations of state-owned companies.

International engagement will help extend the impact of such policies. Some governments will be first movers, reaping the positive outcomes these policies can deliver while also learning lessons about their inherent challenges. Recognising that the scale of the challenge requires co-ordinated global action and the positive effects of replicating success are multiple. The CEM Hydrogen Initiative has created an unparalleled platform for sharing knowledge and best practices with this purpose.

Mobilise investment in production assets, infrastructure and factories

A policy framework that effectively stimulates demand can in turn trigger investment in low-carbon production plants, infrastructure deployment and manufacturing capacity. Meeting ambitious climate goals will require additional policy action to accelerate the use of electrolysers and carbon capture in hydrogen production, develop hydrogen-specific infrastructure and ramp up manufacturing capacity for key hydrogen technologies (e.g. fuel cells and electrolysers).

On the production side, the pipeline of sizeable low-carbon hydrogen projects is impressive, with private companies and investors committing considerable investments. These projects are encountering a bottleneck, however, as governments still need to design and implement support schemes and relevant regulations, risking the loss of valuable time.

Providing tailor-made support for selected, shovel-ready flagship projects through grants, loans and tax breaks (ensuring due diligence to guarantee fair competition), while establishing the support schemes and regulations that will be needed later, can kick-start low-carbon hydrogen expansion. Tailored support for flagship projects can also unlock significant funding to scale up manufacturing capacity for key hydrogen technologies as well as prompt infrastructure development, from which later projects in the region can benefit. This requires flexible regulations that can help de-risk investment, for example through public-private partnerships designed to fit specific projects.

It can be expected that the hydrogen market will initially develop as integrated supply chains from producer to customer, as in the early days of LNG. Transitioning quickly to a liquid market that supports scale-up and widespread hydrogen adoption will require timely development of hydrogen-specific infrastructure, which implies adequate planning and mobilisation of sufficient investment.

Governments face the challenge of balancing rapid development – to ensure that lack of infrastructure does not impede creation of new demand – with the risk of deploying infrastructure too quickly and having it under-utilised or even stranded if demand does not develop sufficiently, particularly for new applications. To avoid such a scenario, infrastructure development should begin with interconnection of major industrial clusters – a low-regret option, since the hydrogen demand of such hubs is more certain than potential demand from new applications. These hubs are also natural locations for establishing hydrogen valleys, where new demand can be developed.

As these hubs typically have natural gas infrastructure in place, repurposing gas pipelines to serve as dedicated hydrogen pipelines is a low-cost option to initiate hydrogen infrastructure development (in fact, timely gas pipeline can accelerate hydrogen system establishment). Then, beyond these initial deployments to support transmission and distribution, governments should begin planning the development of future hydrogen infrastructure, including storage.

Provide strong innovation support to ensure critical technologies reach commercialisation quickly

While key hydrogen technologies are ready to start scaling up, continuous innovation is critical to drive down costs and increase competitiveness. Strong efforts are therefore needed in the near term to demonstrate several emerging technologies at scale to ensure that they reach commercialisation early this decade and unlock the full potential of hydrogen demand. Pertinent demonstration projects include using hydrogen in the DRI process for iron- and steelmaking; producing ammonia and methanol using electrolytic hydrogen produced from variable renewable energy; using hydrogen in heavy-duty transport; and using ammonia in shipping.

Governments should also take policy action now to stimulate funding for (and incentivise development of) next-generation technologies, such as use of hydrogen in shipping; transform hydrogen into synfuels; and use hydrogen to provide high-temperature heat in industrial processes (e.g. in cement kilns). Robust R&D and innovation programmes are necessary to ensure these technologies mature enough in the upcoming decade to be ready for deployment at scale in 2030.

In reality, public budgets for R&D and innovation in low-carbon hydrogen technologies do not offer the support needed to ensure the development pace required to meet long-term climate goals. Governments therefore need to take decisive action against these budget shortfalls.

In its Net zero by 2050 roadmap, the IEA estimates that USD 90 billion of public money needs to be mobilised globally as quickly as possible, with around half dedicated to hydrogen-related technologies. This could reduce investment risks for the private sector and help attract private capital for innovation. Furthermore, it is important for government departments managing R&D portfolios to work closely with national hydrogen research labs and other research centres, as well as with industry, to recognise and respond to the needs of the private sector.

International co-operation will be critical in this area. Implementing the agreed doubling of public R&D within the Mission Innovation initiative can be a first step. In parallel, the convening power of the IEA Hydrogen and Advanced Fuel Cells Technology Collaboration Programmes should be leveraged to facilitate international R&D and information exchange.

Establish appropriate certification, standardisation and regulation regimes

Since adopting hydrogen as a clean fuel is expected to stimulate the development of new markets and value chains, regulatory frameworks, certification schemes and standards will be required to reduce barriers for stakeholders.

In the short term, it is particularly important to develop standards in three domains:

- **International trade**. Standards are required in several areas to develop a global low-carbon hydrogen market. International agreement on a methodology for calculating the carbon footprint of hydrogen production is critical, as it is the basis from which a global certificates market could develop. Importing countries, regions and companies would then be able to decide what carbon footprint threshold they deem acceptable for imported clean hydrogen, although a commonly agreed international standard is vital to avoid future impediments to cross-border trade in hydrogen.
- **Safety**. Safety is a critical topic for low-carbon hydrogen and hydrogen-based fuels. Industry has been able to produce and use hydrogen safely over several decades, but as its use is now expected to expand beyond industry to reach domestic consumers in their vehicles and homes, ensuring safety across all levels is essential. Gaining public acceptance will require the establishment of high safety standards through international co-operation and harmonisation.
- **Technology adoption**. New applications for hydrogen use will result in deployment of new technologies to operate refuelling stations, storage sites and combustion appliances. Internationally harmonised standards for nozzles, valves, burners and storage tanks are therefore necessary to ensure consistent operability around the world.

The IPHE has been leading international efforts in these areas for many years. Governments and industry should thus leverage its progress and collaborate to ensure all required standards are developed quickly enough to prevent the lack of them becoming a barrier to hydrogen adoption. For example, an internationally agreed standard to measure the carbon footprint of hydrogen production on a lifecycle basis will be needed to account for the emissions of the whole hydrogen supply chain, including from electricity generation (where applicable) and fossil fuel production.[39]

Certification is the natural follow-on step after the development of standards. Certification schemes aim to ensure that manufacturers comply with standards adopted internationally to inspire confidence among low-carbon hydrogen users. Furthermore, low-carbon premium markets that rely on product certification can help create demand, mobilise investments and stimulate innovation.

For instance, a car certified to have been manufactured with low-carbon steel (i.e. steel produced in a factory where low-carbon hydrogen has replaced fossil fuel inputs) may have a small price

[39] See the IEA Methane Tracker for estimates on methane emissions from fossil production."

premium over a standard car, which can make it an attractive option for a significant number of consumers across diverse income levels. The same may apply to other consumer products manufactured with low-carbon commodities, such as fertilisers, cement and solvents. For a low-carbon premium market to function effectively, however, it must be founded on a dedicated and reliable system of certificates and labels to provide certainty to consumers about the low-carbon attributes of products they are acquiring.

In addition, a clear, transparent and supportive regulatory framework is necessary to enable development of a robust hydrogen market. As demand rises and suppliers respond, and entirely new value chains and partnerships emerge, regulatory systems will need to be flexible to adapt to market evolution without jeopardising the solidity of business cases needed to attract investment in production assets and infrastructure.

Clear rules for regulated assets and to ensure third-party access will also be needed to avoid new monopolies and market fragmentation in low-carbon hydrogen. However, given the embryonic stage of hydrogen market development, it is premature to apply rigid regulatory principles that work in other mature markets, since they could create a serious risk of regulatory failure or regulatory disconnect. Rather, a gradual and dynamic regulation approach, carefully calibrated to periodic market monitoring (as suggested by the Council of European Energy Regulators and the Agency for the Cooperation of Energy Regulators) can help minimise the risk of failure.

Governments should also consider ways to align other regulatory aspects and policy domains not directly linked to hydrogen markets but that can affect the business case to ensure that, at the very least, they do not render hydrogen projects unappealing. Some examples are:

- Grid fees and levies, which are often developed independently for electricity and gas and can hamper sector coupling.
- State aid rules, which are of critical importance to ensure fair competition. In some jurisdictions, they may need to be adjusted to facilitate initial deployment of low-carbon hydrogen technologies.
- Spatial planning and licensing, which in some countries can be a long and cumbersome process. Current planning and approval processes do not yet include hydrogen and may need to be revised. Governments and local authorities can help co-ordinate infrastructure planning processes among public agencies, industry and citizens.
- Possible tariff and non-tariff trade barriers, which can hamper hydrogen trade. A strong case exists for striving for uninhibited and smooth global trade in hydrogen, facilitated by early identification of potential barriers and, where necessary, undertaking international efforts to harmonise and tackle them.
- Energy taxation, which ideally should follow the “polluter pays principle” and systematically favour zero-/low-carbon solutions over fossil fuel alternatives.
- Fossil fuel subsidies, which still exist in several countries and can distort the developing hydrogen market. The IEA has long been recommending timely phase out of such subsidies.

Finally, financial market regulations for sustainable financing and initiatives for environmental, social and corporate governance – both national and international – are increasingly helpful to nudge investors towards clean energy, including low-carbon hydrogen. Governments should actively encourage these trends (e.g. by mandating that multilateral banks help fund hydrogen scale-up) to leverage their own public investments.

Annexes

Abbreviations and acronyms

AEM	anion exchange membrane
AFC	alkaline fuel cells
AFC TCP	Advanced Fuel Cell Technology Collaboration Programme
ALK	alkaline
APS	Announced Pledges Scenario
ATR	autothermal reforming
AUD	Australian dollar
BEV	battery electric vehicle
BF	blast furnace
CAD	Canadian dollar
CAPEX	capital expenditure
CCfD	carbon contracts for difference
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CCU	carbon capture and use
CCUS	carbon capture, utilisation and storage
CEM H2I	Clean Energy Ministerial Hydrogen Initiative
CNY	Chinese yuan
CO_2	carbon dioxide
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAC	direct air capture
DRI	direct reduced iron
DRI-EAF	direct reduced iron - electric arc furnace
EHB	European hydrogen backbone
EIB	European Investment Bank
EOR	enhanced oil recovery
EPC	engineering, procurement and construction
ESMR	electrified steam methane reforming
EU	European Union
EU ETS	EU Emissions Trading Scheme
EUR	Euro
EV	electric vehicle
FC	fuel cell
FCEV	fuel cell electric vehicle
FCH JU	Fuel Cells and Hydrogen Joint Undertaking
FID	final investment decision
FT	Fischer-Tropsch
GBP	British pound sterling
GH_2	gaseous hydrogen
GHG	greenhouse gases
GHR	gas-heated reformer

H_2	hydrogen
HDV	heavy-duty vehicle
HEM	Hydrogen Energy Ministerial
HEV	hybrid electric vehicle
HRS	hydrogen refuelling station
HT	high throughput
IAE	Institute of Applied Energy
ICE	internal combustion engine
IEA	International Energy Agency
IEA GHG	IEA Greenhouse Gas R&D Programme
IFA	International Fertilizer Industry Association
IMO	International Maritime Organization
IPCEI	Important Projects of Common European Interest
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy
IRENA	International Renewable Energy Agency
IPCEI	Important Projects of Common European Interest
JHyM	Japan Hydrogen Mobility
JPY	Japanese yen
KRW	Korean won
LCV	light commercial vehicle
LDV	light-duty vehicle
LH_2	liquid hydrogen
LHV	lower heating value
LNG	liquefied natural gas
LOHC	liquid organic hydrogen carrier
LPG	liquefied petroleum gas
LNG	liquefied natural gas
M&A	mergers and acquisitions
MCFC	molten carbonate fuel cell
MeOH	methanol
MI	Mission Innovation
MOC	memorandum of collaboration
MOU	memorandum of understanding
MTO	methanol to olefin
NH_3	ammonia
NOK	Norwegian krone
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory
NZE	Net zero Emission Scenario
OEM	original equipment manufacturer
OPEX	operating expenditure
PAFC	phosphoric acid fuel cell
PE	private equity
PEM	proton exchange membrane
PEMFC	proton exchange membrane fuel cell
PIPE	private investment in public equity
PLDV	passenger light-duty vehicle

POx	partial oxidation
PtG	power-to-gas
PtL	power-to-liquids
PV	photovoltaic
R&D	research and development
RD&D	research, development and demonstration
SCR	selective catalytic reduction
SMR	steam methane reforming
SOEC	solid oxide electrolysis cell
SOFC	solid oxide fuel cell
SUV	sport utility vehicle
TCO	total cost of ownership
TCP	Technology Collaboration Programme
TRL	technology readiness level
TSO	transmission system operator
UK	United Kingdom
UN	United Nations
US	United States
USD	United States dollar
VC	venture capital
VRE	variable renewable energy
WEF	World Economic Forum
ZEV	zero emissions vehicle

Units of measure

°C	degree Celsius
bbl	barrel
bcm	billion cubic metres
EJ	exajoule
Gt	gigatonnes
Gt CO_2	gigatonnes of carbon dioxide
GW	gigawatt
GWh	gigawatt-hour
kg	kilogramme
kg H_2	kilogramme of hydrogen
kg CO_2eq	kilogrammes of carbon-dioxide equivalent
kt	kilotonnes
kt H_2	kilotonnes of hydrogen
kW	kilowatt
kWh	kilowatt-hour
mcm	million cubic metres
MBtu	million British thermal units
MJ	megajoule

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The principal IEA authors and contributors were (in alphabetical order): Thibaut Abergel (buildings), Julien Armijo (supply), Praveen Bains (supply), Simon Bennett (investments and innovation), Niels Berghout (CCUS), Ekta Meena Bibra (transport), Sara Budinis (CCUS), Elizabeth Connelly (transport), Chiara Delmastro (buildings), Araceli Fernandez Pales (end-use sectors and innovation), Alexandre Gouy (industry), Ilkka Hannula (power), Taku Hasegawa (supply and trade), Jean-Baptiste Le Marois (investments and innovation), Olivier Lelouch (refining), Peter Levi (industry), Raimund Malischek (CCUS), Hana Mandova (industry), Gergely Molnár (infrastructure), Leonardo Paoli (innovation), Faidon Papadimoulis (data management and modelling), Francesco Pavan (supply), Kristine Petrosyan (refining), Maxwell Pisciotta (CCUS), Amalia Pizarro Alonso (infrastructure), Jacopo Tattini (transport), Jacob Teter (transport), Tiffany Vass (industry) and Per-Anders Widell (CEM H2I).

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APPENDIX 4 UK HYDROGEN STRATEGY

HM Government

UK Hydrogen Strategy

August 2021

CP 475

UK Hydrogen Strategy

Presented to Parliament
by the Secretary of State for Business, Energy & Industrial Strategy
by Command of Her Majesty

August 2021

CP 475

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Contents

Ministerial foreword

As the Prime Minister made clear when he launched his *Ten Point Plan for a Green Industrial Revolution* last year, developing a thriving low carbon hydrogen sector in the UK is a key plank of the government's plan to build back better with a cleaner, greener energy system. With the potential to overcome some of the trickiest decarbonisation challenges facing our economy – including our vital industrial sectors – and secure economic opportunities across the UK, low carbon hydrogen has a critical role to play in our transition to net zero.

Working with industry, our ambition is for 5GW of low carbon hydrogen production capacity by 2030 for use across the economy. This could produce hydrogen equivalent to the amount of gas consumed by over 3 million households in the UK each year. This new, low carbon hydrogen could help provide cleaner energy to power our economy and our everyday lives – from cookers to distilleries, film shoots to power plants, waste trucks to steel production, and 40 tonne diggers to the heat in our homes.

Meeting our ambition means rapid ramp up of production and use of hydrogen over the coming decade. In every country of the UK, there are ambitious, world-leading projects ready to deploy at scale, saving carbon and creating jobs. These trailblazers will help us fully understand the costs around hydrogen, its safety where hydrogen is being used in new ways, and just how far it can contribute to reducing our emissions.

The time for real world action is now. We have developed the first ever UK Hydrogen Strategy to set out clearly the key steps we need to take in the coming months and years to deliver against the promise that hydrogen presents – an exciting moment for technology providers, energy companies large and small, investors, innovators, and government at all levels.

Our ambition for hydrogen goes beyond decarbonisation. It also means a focus on supporting industry to develop sustainable, home-grown supply chains, create high quality jobs, and capitalise on British innovation and expertise. It means incentivising private investment and looking to increase export opportunities. It means strengthening our industrial heartlands, boosting our economy and driving national growth.

The Hydrogen Strategy builds on our national strengths. UK companies are already at the forefront of global hydrogen technology development. Our geology, infrastructure and technical know-how make us ideally positioned to be a global leader in hydrogen. We have a strong history of collaboration between government, industry and innovators to tackle climate change and grow our economy.

Alongside this Strategy we are also publishing a number of consultations – seeking views on our preferred Hydrogen Business Model, the design of our flagship £240m Net Zero Hydrogen Fund, and a UK Low Carbon Hydrogen Standard. These are policies that industry, including members of the Hydrogen Advisory Council which I co-Chair, have told us are key to drive early expansion of the UK hydrogen economy. This substantial suite of documents is supported by a detailed Analytical Annex and a report on Hydrogen Production Costs.

Taken together, the UK Hydrogen Strategy and supporting policy package lay the foundations for a thriving hydrogen economy, one that can support our trajectory to achieving our world-leading Sixth Carbon Budget and net zero commitments. I look forward to continuing to work closely with industry, innovators and investors to deliver real action on hydrogen, with real benefits for UK businesses and communities.

The Rt Hon Kwasi Kwarteng MP
Secretary of State for Business, Energy & Industrial Strategy

Executive summary

Hydrogen is one of a handful of new, low carbon solutions that will be critical for the UK's transition to net zero. As part of a deeply decarbonised, deeply renewable energy system, low carbon hydrogen could be a versatile replacement for high-carbon fuels used today – helping to bring down emissions in vital UK industrial sectors and providing flexible energy for power, heat and transport. The UK's vision, resources and know-how are ideally suited to rapidly developing a thriving hydrogen economy. Our world-class innovation and expertise offer opportunities for UK companies in growing domestic and global markets. The UK Hydrogen Strategy sets out how we will drive progress in the 2020s, to deliver our 5GW production ambition by 2030 and position hydrogen to help meet our Sixth Carbon Budget and net zero commitments.

The scale of the challenge is clear: with almost no low carbon production of hydrogen in the UK or globally today, meeting our 2030 ambition and delivering decarbonisation and economic benefits from hydrogen will require rapid and significant scale up over coming years. The work starts now.

The UK Hydrogen Strategy takes a holistic approach to developing a thriving UK hydrogen sector. It sets out what needs to happen to enable the production, distribution, storage and use of hydrogen and to secure economic opportunities for our industrial heartlands and across the UK. Guided by clear goals and principles, and a roadmap showing how we expect the hydrogen economy to evolve and scale up over the coming decade, the Strategy combines near term pace and action with clear, long term direction to unlock the innovation and investment critical to meeting our ambitions.

Chapter 1 of the Strategy sets out the case for low carbon hydrogen, briefly outlining how it is produced and used today before explaining its potential role in meeting net zero and in providing opportunities for UK firms and citizens to be at the forefront of the global transition to net zero. It explains how our 2030 ambition can deliver emissions savings to help meet our carbon budgets, as well as jobs and economic growth, helping to level up across the UK. It sets out our strategic framework, including our vision for 2030, the principles guiding our action, challenges to overcome and our key outcomes by 2030. Finally, it outlines the important role of the devolved nations in the UK's hydrogen story, and how government is working closely with the devolved administrations to help hydrogen contribute to emissions reductions and deliver local economic benefits across the UK.

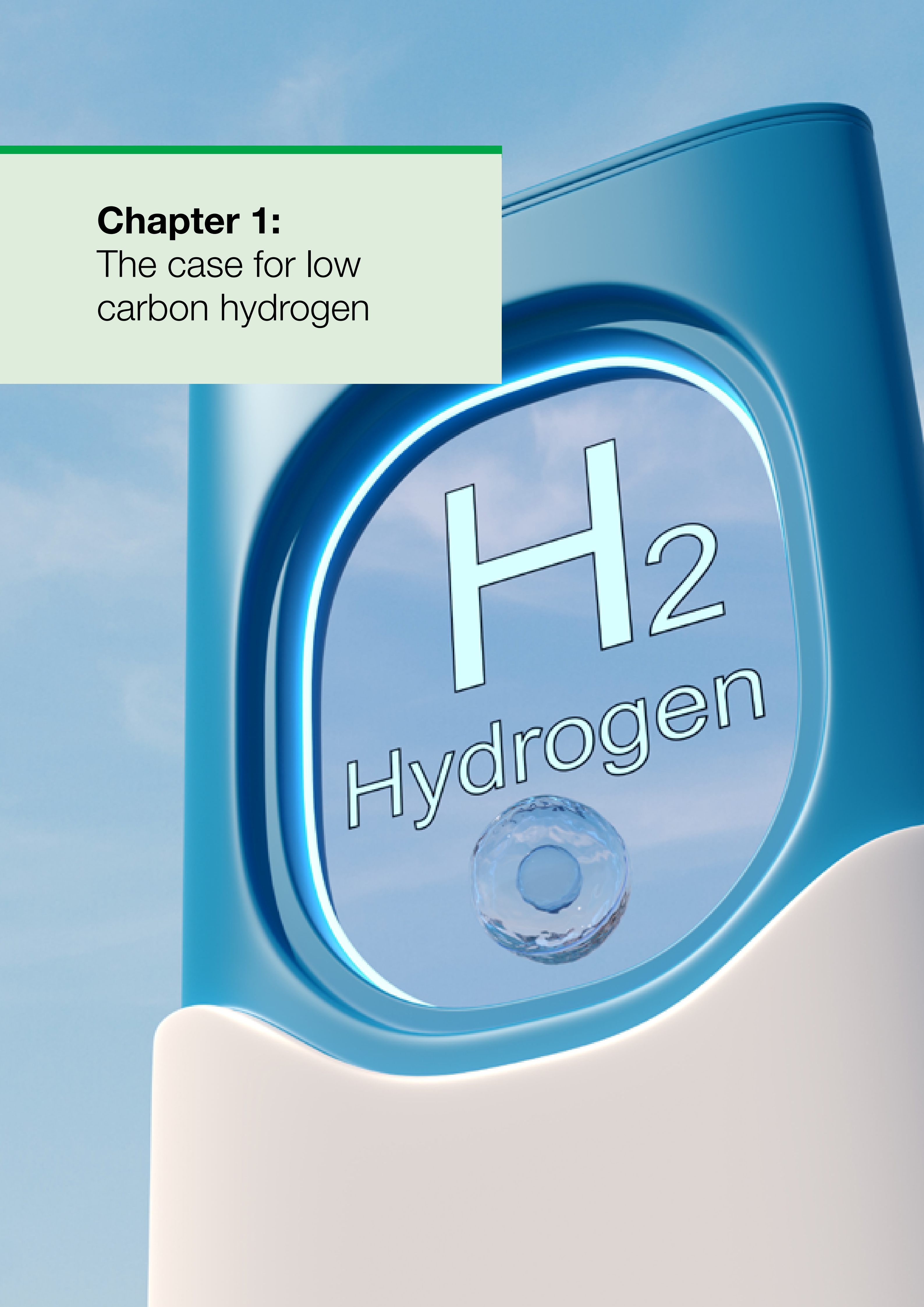
Chapter 2 forms the core of the Strategy, setting out our whole-systems approach to developing the UK hydrogen economy. It opens with our 2020s roadmap, which sets out a shared understanding, developed in partnership with industry, of how the hydrogen economy needs to evolve over the course of the decade and into the 2030s – and what needs to be in place to enable this. The chapter then considers each part of the hydrogen value chain in turn – from production, to networks and storage, to use across industry, power, buildings and transport – and outlines the actions we will take to deliver our 2030 ambition and position hydrogen for further scale up on a pathway to Carbon Budget Six and net zero. Finally, it considers how we will develop a thriving hydrogen market by 2030 – including the market and regulatory frameworks underpinning it and their interaction with the wider energy system, and the need to improve awareness and secure buy-in from potential users of hydrogen.

Chapter 3 explains how we will work to secure economic opportunities across the UK that can come from a thriving hydrogen economy – learning from the development of other low-carbon technologies and building this into our approach from the outset. It sets out how we will: build world class, sustainable supply chains across the full hydrogen value chain; create good quality jobs and upskill industry to drive regional growth and ensure that we have the right skills in the right place at the right time; maximise our research and innovation strengths to accelerate cost reduction and technology deployment, and to capitalise on the UK's world-leading expertise; and create an attractive environment to secure the right investment in UK projects while maximising the future export opportunities presented by a low-carbon hydrogen economy.

Chapter 4 builds on this to show how the UK is working with other leading hydrogen nations to drive global leadership on the development of low carbon hydrogen to support the world's transition to net zero. It sets out the UK's active role in many of the key institutions driving multilateral collaboration on hydrogen innovation and policy, and our ambition to actively seek opportunities for further collaboration with key partner countries to spur the development of thriving domestic, regional and ultimately international hydrogen markets.

Chapter 5 concludes the Strategy, setting out how we will track our progress to ensure we are developing a UK hydrogen economy in line with the principles and outcomes set out in Chapter 1 and our roadmap in Chapter 2. This chapter explains our approach – how we will be flexible, transparent, efficient and forward-looking in monitoring progress – and sets out the potential indicators and metrics we will use to track how we are delivering against our outcomes. This will help ensure that we can deliver our 2030 ambition and realise our vision for a low carbon hydrogen economy that drives us towards Carbon Budget Six and net zero, while making the most of the opportunities that hydrogen holds for the UK.

Chapter 1: The case for low carbon hydrogen



Low carbon hydrogen will be critical for meeting the UK's legally binding commitment to achieve net zero by 2050, and Carbon Budget Six in the mid-2030s on the way to this. Hydrogen can support the deep decarbonisation of the UK economy, particularly in 'hard to electrify' UK industrial sectors, and can provide greener, flexible energy across power, heat and transport. Moreover, the UK's geography, geology, infrastructure and expertise make it particularly suited to rapidly developing a low carbon hydrogen economy, with the potential to become a global leader on hydrogen and secure economic opportunities across the UK.

Hydrogen is one of a handful of new low carbon solutions which can help the UK to achieve its world-leading emissions reductions target for Carbon Budget Six (CB6), and net zero by 2050. As set out in the Prime Minister's *Ten Point Plan for a Green Industrial Revolution*, working with industry, government is aiming for 5GW of low carbon hydrogen production capacity by 2030 for use across the economy. With virtually no low carbon hydrogen produced or used currently, particularly to supply energy, this will require rapid and significant scale up from where we are today.

The *Ten Point Plan* announced new funds and policies that will set us on the pathway to meet this ambition, including £240 million for government co-investment in production capacity through the Net Zero Hydrogen Fund (NZHF), a hydrogen business model to bring through private sector investment, and plans for a revenue mechanism to provide funding for the business model. Continued improvements in hydrogen technologies, enabled by pioneering UK research and innovation and international collaboration, will also be critical. The *Ten Point Plan* designated hydrogen as a key priority area in the Net Zero Innovation Portfolio, a £1 billion fund to accelerate commercialisation of low-carbon technologies and systems for net zero.

The 2020s will be critical for supporting energy users best suited to hydrogen as a low carbon solution to get ready to use it. We are accelerating work in this area. We are supporting fuel switching to hydrogen in industry through the £315 million Industrial Energy Transformation Fund and £20 million Industrial Fuel Switching Competition; establishing the evidence base for hydrogen use and storage in the power sector; rolling out demonstration competitions and trials (subject to funding) for the use of hydrogen in road freight, shipping and aviation; and pioneering trials of hydrogen heating – beginning with a hydrogen neighbourhood trial by 2023, followed by a large hydrogen village trial by 2025, and potentially a hydrogen town pilot before the end of the decade. We are working with the Health and Safety Executive (HSE) and industry to assess the potential for 20 per cent hydrogen blending into the gas network, and supporting the development of prototype 'hydrogen-ready' appliances such as boilers and cookers. The *Energy White Paper*, *Industrial Decarbonisation Strategy* and the recently published *Transport Decarbonisation Plan* set out further actions we are taking to bring forward hydrogen demand across industry, power, heat and transport.

This Strategy goes further, setting out a series of additional commitments and actions which show how government, in partnership with industry, the research and innovation community and wider civil society, will deliver our vision for a UK hydrogen economy.

By acting now we will be better positioned to stimulate domestic supply chains, enabling UK businesses to serve increasing international demand for hydrogen goods and services. Current evidence suggest that developing a UK hydrogen economy could also support over 9,000 jobs by 2030 – and up to 100,000 jobs by 2050 – across our industrial heartlands and across the UK.[1]

1.1 Hydrogen in the UK today

The UK has a longstanding history with hydrogen. Since the discovery of 'inflammable air' by Henry Cavendish in the mid-18th century, hydrogen has played a role in our everyday lives, from helping to fertilise our fields to providing part of the 'town gas' that lit our streets and heated our homes until the late 20th century.

There are almost no abundant natural sources of pure hydrogen, which means that it has to be manufactured. The most common production route is steam methane reformation, where natural gas is reacted with steam to form hydrogen. This is a carbon-intensive process, but one which can be made low carbon through the addition of carbon capture, usage and storage (CCUS) – to produce a gas often called 'blue hydrogen'. Hydrogen can also be produced through electrolysis, where electricity is used to split water into hydrogen and oxygen – gas from this process is often referred to as 'green hydrogen' or zero carbon hydrogen when the electricity comes from renewable sources. Today most hydrogen produced and used in the UK and globally is high carbon, coming from fossil fuels with no carbon capture; only a small fraction can be called low carbon.[2] For hydrogen to play a part in our journey to net zero, all current and future production will need to be low carbon.

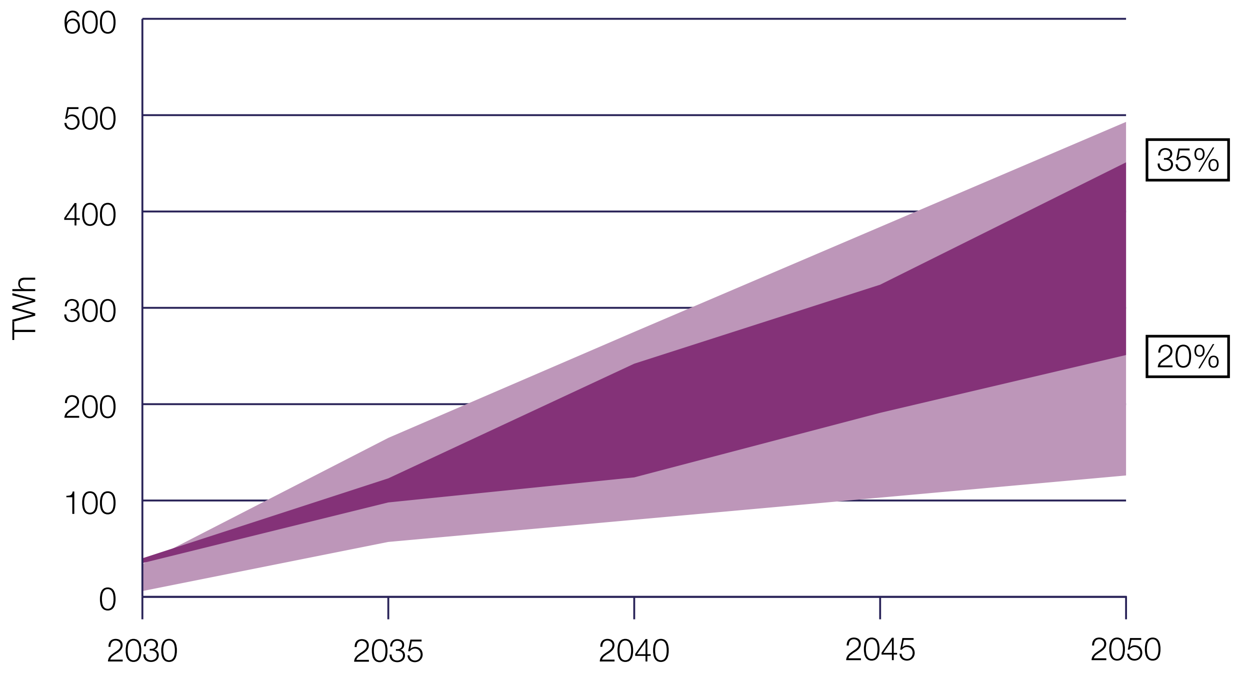
Current UK hydrogen production and use is heavily concentrated in chemicals and refineries.[3] This hydrogen, largely produced from natural gas (without carbon capture), is used as a feedstock, or input, into making other chemicals and plays a variety of roles in refineries to convert crude oil into different end products. In these two sectors, production and use of hydrogen usually happen on the same site, often integrated into a single industrial facility. Hydrogen is also used as a fuel, in far smaller volumes, across the UK. Hydrogen cars, trucks, buses and marine vessels are already operating and supported by a network of refuelling stations, with plans for hydrogen trains and aircraft underway. Hydrogen will soon be blended with natural gas and supplied safely to over 650 homes as part of a trial in Winlaton in the north-east of England.

British companies such as ITM Power, Johnson Matthey and Ceres Power are already producing the technology for low and zero carbon hydrogen, and they and many others are pushing new innovations all the time. The Orkney Islands in Scotland have generated global interest in a range of projects that show how challenges in a local energy system can sometimes be overcome with hydrogen; here producing hydrogen from excess renewable electricity that would otherwise has gone to waste, and using it to support decarbonisation of road transport, heat and ferry related activities. Across the UK, pioneering production and use projects have provided lessons, stimulated further research and innovation, and pointed the way to what is needed to deploy production capacity at pace and scale, and to unlock hydrogen as a low carbon fuel for new applications across the energy system.

1.2 The role of hydrogen in meeting net zero

Low carbon hydrogen will be essential for achieving net zero, and ahead of that, meeting our world-leading CB6 target to reduce emissions 78 per cent on 1990 levels by 2035. Analysis by BEIS for CB6 suggests 250-460TWh of hydrogen could be needed in 2050,[4] making up 20-35 per cent of UK final energy consumption (see Figure 1.2 below).[5] The size of the hydrogen economy in 2050 will depend on a number of factors – including the cost and availability of hydrogen and hydrogen-using technology relative to alternatives, such as electrification, biomass and use of CCUS. Nonetheless, there is consensus, from the Climate Change Committee (CCC) and others, that we will need significant amounts of low carbon hydrogen on the system by 2050.

Figure 1.2: Hydrogen demand and proportion of final energy consumption in 2050



% = hydrogen as proportion of total energy consumption in 2050

Source: Central range – illustrative net zero consistent scenarios in CB6 Impact Assessment. Full range – based on whole range from UK Hydrogen Strategy Analytical Annex. Final energy consumption from ECUK (2019).

As a gas, hydrogen has a distinct set of characteristics. It can be used in a fuel cell or combusted in a boiler, turbine or engine to generate heat or electricity. It can also be stored in various ways, including at very large scales, and can be transported to different end users, in much the same way as natural gas or liquid fuels today. Hydrogen is also an essential input to a range of chemical processes and in industrial production.

Low carbon hydrogen will play an important complementary and enabling role alongside clean electricity in decarbonising our energy system. It is suited to use in a number of sectors where electrification is not feasible or is too costly, and other decarbonisation options are limited. This may include generation of high temperature heat, as in industrial furnaces, and long-distance and heavy-duty transport. Similarly it is useful in areas where the flexibility and stability of a gas is valued, for example large scale or long duration energy storage and flexible power generation. However, hydrogen can only be considered as a decarbonisation option if it is readily available, at the right price, the right volume and with sufficient confidence it is low carbon. In addition, potential users must be able to purchase hydrogen-using equipment, with proper assurances about safety and reliability. This will be our focus for the 2020s, in order to deliver our 2030 ambition and set us on the pathway to CB6 and net zero.

1.3 The UK's hydrogen opportunity

As a result of its geography, geology, infrastructure and capabilities, the UK has an important opportunity to demonstrate global leadership in low carbon hydrogen and to secure competitive advantage. Building hydrogen production and enabling use across multiple sectors will be critical for developing domestic capacity and capabilities, and securing green jobs across the UK.

Developing a hydrogen economy requires tackling the 'chicken and egg' problem of growing supply and demand in tandem, and the UK offers favourable conditions for both to readily expand. When it comes to production, our 'twin track' approach capitalises on the UK's potential to produce large quantities of both electrolytic 'green' and CCUS-enabled 'blue' hydrogen. The UK reduced its power sector emissions by over 70 per cent between 1990 and 2019,[6] and generates more electricity from offshore wind than any other country.[7] The *Energy White Paper*, published in December 2020, sets out how we will expand renewable generation while decarbonising power sector emissions further, including through our ambition to quadruple offshore wind capacity to 40GW by 2030, and pursue new large-scale nuclear while investing in small-scale nuclear technologies. This low carbon electricity will be the primary route to decarbonisation for many parts the energy system, and will also support electrolytic production of hydrogen.

The *Energy White Paper* also sets out how the UK will deploy and support CCUS technology and infrastructure, with £1 billion of support allocated up to 2025 and a commitment to set out details of a revenue mechanism to bring through early-stage private investment in industrial carbon capture and hydrogen projects. The UK has the technology, know-how and storage potential to scale up CCUS across the country, unlocking new routes to CCUS-enabled hydrogen production.

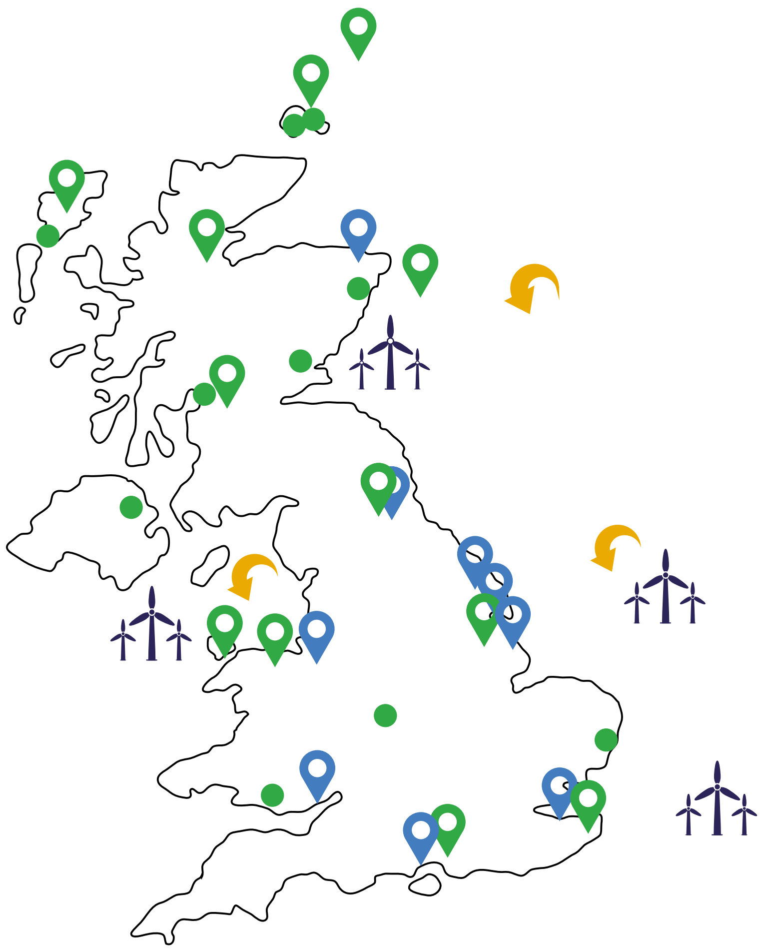
Early deployment of CCUS technology and infrastructure will likely be located in industrial clusters. Many of these are in coastal locations, with important links to CO_2 storage sites such as disused oil and gas fields. Government aims to establish CCUS in four industrial clusters by 2030 at the latest, supporting our ambition to capture 10Mt/CO_2 per annum.

In turn, industrial clusters and wider industry are significant potential demand centres for low carbon hydrogen. Today, numerous industrial sectors from chemicals to food and drink are exploring the role that hydrogen can play in their journey to net zero. UK Research and Innovation's (UKRI's) Industrial Decarbonisation Challenge provides up to £170 million – matched by £261 million from industry – to invest in developing industrial decarbonisation infrastructure including CCUS and low carbon hydrogen.

Figure 1.3: Proposed UK electrolytic and CCUS-enabled hydrogen production projects

Key

- Electrolytic production project (under 5MW)
- Electrolytic production project (over 5MW)
- CCUS enabled production project (100 MW+)
- CO_2 storage potential
- Offshore wind



Note: Includes plans and proposals for known projects that are in the public domain. Many more projects are under development in all parts of the UK. BEIS are continuing to gather intelligence on new projects as they emerge.

The UK also has decades of experience in production, distribution, storage, use and regulation of gas. Our widespread use of natural gas for power generation and for heat in industry and homes means that we have potential supply routes and numerous potential use cases for hydrogen gas. The UK also has favourable geology for large-scale storage of hydrogen, and is already storing hydrogen in salt caverns and exploring storage in disused oil and gas fields under the North Sea.

In addition, our well-developed North Sea oil and gas sectors and experience in renewables mean that the UK has developed supply chain strengths and innovative companies across the value chain poised to take advantage of the economic opportunities from developing low carbon hydrogen technologies. UK companies such as ITM Power, Johnson Matthey and Ceres Power are already recognised as being at the forefront of hydrogen technology development worldwide. Building on this strong base, we will draw on lessons from offshore wind and other low carbon technologies and aim to capitalise on our world-leading expertise in research and innovation and decarbonisation to put the UK at the forefront of emerging global hydrogen markets and opportunities.

The UK is well positioned to be a world leader in low carbon hydrogen production and use, delivering green jobs and growth to support levelling up across our industrial heartlands and across the UK. But we can only realise these economic opportunities if we act now to put in place the necessary environment and support to develop robust supply chains, upskill our people and secure high-quality jobs, and lay the groundwork to unlock investment and export opportunities. Our strategy seeks to maximise the economic benefits from a UK hydrogen economy and seize the potential of both domestic and international markets.

1.4 Our ambition for a thriving hydrogen economy by 2030

We recognise the importance of a clear goal alongside long term policy frameworks in bringing forward low carbon technologies. Our ambition for 5GW of low carbon hydrogen production capacity by 2030 is a signal of the government's firm commitment to work with industry to develop a strong and enduring UK hydrogen economy. This ambition is a means to an end, rather than an end in itself – positioning the UK hydrogen economy for the scale up needed to support CB6 in the mid-2030s and net zero by 2050, and to deliver clean growth opportunities across the UK. We use "our 2030 ambition" in places throughout this strategy as shorthand for this wider vision for the UK hydrogen economy by the end of the decade.

It is not possible today, in 2021, to predict with certainty the size of the future hydrogen market in a net zero energy system, nor the best pathway to reach that. We recognise that the UK has huge potential to produce and use low carbon hydrogen, and that many in industry think we could go further and faster. We welcome this drive and ambition and will continue to work with industry to deliver the strategic direction and supporting policy environment to achieve our 2030 ambition and position the UK hydrogen economy for the future growth and scale up needed for CB6 and net zero.

Delivering our 2030 ambition will yield significant emissions savings. Our modelling suggests that the use of low carbon hydrogen enabled by 5GW production capacity could deliver total emissions savings of around 41MtCO_2e between 2023 and 2032, equivalent to the carbon captured by 700 million trees over the same time period.[8] This covers the period of the UK's Fourth and Fifth Carbon Budgets (CB4 and 5), and will contribute to achieving our Nationally Determined Contribution (NDC) under the Paris Agreement of reducing emissions by 68 per cent compared to 1990 levels by 2030. Further scale up of low carbon hydrogen post-2030 would yield even larger emissions savings, and will play an important role in delivering CB6, to be set out in more detail in the government's forthcoming Net Zero Strategy.

Our 5GW ambition would also mean the creation of a thriving new hydrogen industry, which could support over 9,000 jobs and £900 million of GVA by 2030.[9] Government investment in hydrogen to de-risk early projects could unlock over £4 billion of private sector co-investment up to 2030.[10] Our ambition also sets us on a promising pathway post-2030. Our analysis shows that, under a high hydrogen scenario, up to 100,000 jobs and £13 billion of GVA could be generated from the UK hydrogen economy by 2050.[11]

Many countries around the world have signalled the importance of low carbon hydrogen in reducing emissions, and there is an expectation that a global market for trade in hydrogen will develop in the long term. However, it is unlikely that market will be mature by 2030, meaning that the UK cannot, and would not want to, rely solely on low carbon hydrogen imports. An over-reliance on imports could create risks around the security of supply for hydrogen and associated investment in the wider value chain. It would also reduce opportunities for UK companies to leverage domestic capabilities and strengths and translate these into clean growth opportunities. In contrast, moving quickly to develop a strong UK hydrogen economy by 2030 can help ensure security of supply and wider investment, create high-quality and sustainable jobs, and position UK companies to take advantage of opportunities in international markets.

We aspire to take a leading global role in developing low carbon hydrogen technologies and markets, working with our international partners including through existing initiatives for collaboration. This will be particularly important in the lead up to the UK hosting COP26 later this year, as we seek to turbo-charge the development and deployment of low carbon technologies that will help countries achieve their clean energy transitions – but will continue beyond COP26, as we pursue opportunities to work with other leading global hydrogen nations in helping to build a global hydrogen economy.

1.5 A strategic framework for the UK Hydrogen Strategy

In developing a UK hydrogen economy, it will be important that we set clear and consistent direction to give industry and investors confidence and certainty, whilst remaining flexible to ensure that we act on learning from early projects and can take decisions which offer the greatest decarbonisation and economic value in the long term. Our strategic framework informs the policy direction and commitments set out in this strategy, and will guide our actions over the course of the 2020s to provide a coherent long term approach.

Our vision

Our vision is that by 2030, the UK is a global leader on hydrogen, with 5GW of low carbon hydrogen production capacity driving decarbonisation across the economy and clear plans in place for future scale up towards Carbon Budget 6 and net zero, supporting new jobs and clean growth across the UK.

Our principles

Our principles will guide future policy decisions and government action, providing clarity on future policy direction for investors and users:

- **Long term value for money for taxpayers and consumers:** To deliver value for UK taxpayers and consumers we will seek to minimise the cost of action, and drive down costs over the long term, as we reach for our 5GW ambition and beyond to CB6 and net zero.
- **Growing the economy whilst cutting emissions**: We will harness opportunity to create new, high-quality jobs to support levelling up, including in transition from existing high carbon sectors. We will ensure that the actions we take are aligned to our net zero target, recognising that hydrogen production will need to become increasingly low carbon over time.
- **Securing strategic advantages for the UK:** We will nurture UK capabilities and technological expertise to grow new industries of the future, so that UK companies can position themselves at the forefront of the growing global hydrogen market. We will support private sector innovation, develop policy to mobilise private investment and promote UK export opportunities.
- **Minimising disruption and cost for consumers and households:** We will build on our successful hydrogen research and innovation to date to reduce costs, address risks and provide safety and technical assurance of technologies at commercial readiness, focusing on 'learning by doing' in the 2020s to minimise disruption and cost for consumers and households, and prime the UK market for expansion.
- **Keeping options open, adapting as the market develops:** There are uncertainties around the role of hydrogen in 2030 and out to 2050, including the likely split of production methods and scale of demand. We will seek to ensure optionality to deliver a number of credible pathways to 2050, bringing forward a range of technologies that could support our 2030 ambition and CB6 and net zero targets.
- **Taking a holistic approach:** We will focus on what needs to be done across the whole hydrogen system, supporting coordination across all those who need to play their part, and ensuring we stay in step with developments in the wider energy system as the UK drives to net zero.

We recognise that there may be trade-offs within and between some of these principles at any point in time. For example, the levelised cost of hydrogen using electrolytic production technology is higher today than for CCUS-enabled hydrogen, and it will take time for production to reach industrial scale. That said, with the right support today, this technology presents a genuine opportunity for export of UK expertise and technology, and there is also significant potential for longer-term cost reduction with continued innovation, scale up of manufacture and access to increased amounts of low-cost renewable electricity. This is a clear example of the need to seek balance across these principles in current and future policy decisions.

Challenges to overcome

There are a number of strategic challenges across the value chain that will need to be overcome in order to produce and use hydrogen at scale in the UK:

- **Cost of hydrogen relative to existing high carbon fuels:** Although costs are likely to reduce significantly and rapidly as innovation and deployment accelerate, hydrogen is currently much more costly to produce and use than existing fossil fuels.
- **Technological uncertainty:** While some technology is already in use, many applications need to be proven at scale before they can be widely deployed.
- **Policy and regulatory uncertainty:** Hydrogen is a nascent area of energy policy; industry is looking to government to provide capital and revenue support, regulatory levers and incentives, assurance on quality and safety, direction on supply chains and skills, and broader strategic decisions.
- **Need for enabling infrastructure:** The use of hydrogen will require new networks and storage, as well as integration with CCUS, gas and electricity networks.
- **Need for supply and demand coordination:** Developing a hydrogen economy will require overcoming the 'chicken and egg' problem of needing to develop new production and use cases in tandem and balancing supply and demand, including potentially through storage over time.
- **Need for 'first-of-a-kind' and 'next-of-a-kind' investment and deployment:** Scaling up a low carbon hydrogen economy will require addressing 'first mover disadvantage' and other barriers to bring forward early projects while establishing a sustainable environment for increasing investment and deployment in the longer term.

The chapters that follow discuss these challenges in further detail and outline how government will overcome them to develop a thriving UK hydrogen economy.

Outcomes by 2030

As we head towards 2030, we will measure our success across a range of strategic outcomes:

- **Progress towards 2030 ambition:** 5GW of low carbon hydrogen production capacity with potential for rapid expansion post-2030; hope to see 1GW production capacity by 2025.
- **Decarbonisation of existing UK hydrogen supply:** Existing hydrogen supply decarbonised through CCUS and/or supplemented by electrolytic hydrogen injection.
- **Lower cost of hydrogen production:** A decrease in the cost of low carbon hydrogen production driven by learning from early projects, more mature markets and technology innovation.
- **End-to-end hydrogen system with a diverse range of users:** End user demand in place across a range of sectors and locations across the UK, with significantly more end users able and willing to switch.
- **Increased public awareness:** Public and consumers are aware of and accept use of hydrogen across the energy system.
- **Promote UK economic growth and opportunities, including jobs:** Established UK capabilities and supply chain that translates into economic benefits, including through exports. UK is an international leader and attractive place for inward investment.
- **Emissions reduction under Carbon Budgets 4 and 5:** Hydrogen makes a material contribution to the UK's emissions reduction targets, including through setting us on a pathway to achieving CB6.
- **Preparation for ramp up beyond 2030 – on a pathway to net zero:** Requisite hydrogen infrastructure and technologies are in place with potential for expansion. Well established regulatory and market framework in place.
- **Evidence-based policy development:** Modelling of hydrogen in the energy system and input assumptions improved based on wider literature, qualitative and quantitative evidence and real-world learning. Delivery evidence from innovation and deployment projects collected and used to improve policy making.

We are developing clear indicators and metrics to monitor progress against these outcomes (set out in Chapter 5). This will be important to ensure that we remain on track to rapidly scale up activity across the hydrogen value chain over the course of the 2020s – so that we can realise our 2030 vision, and can position the UK hydrogen economy for scale up beyond this to CB6 and net zero, while making the most of the opportunities that hydrogen holds for UK businesses and citizens.

As our policy work progresses, we will provide regular updates to the work and actions outlined in this strategy – with the first of these updates expected in early 2022. We intend to publish these updates at half-yearly intervals to provide a clear signal of policy direction and provide industry and our other stakeholders with certainty as our thinking develops.

1.6 Hydrogen in Scotland, Wales and Northern Ireland

Developing a hydrogen economy is a whole-UK story, with potential to produce and use low carbon hydrogen right across the UK and provide local economic benefits, in support of UK and devolved administration net zero plans. The government is working with the devolved administrations to support research and innovation and deployment of low carbon hydrogen technologies, and there are already pioneering projects and companies producing and using low carbon hydrogen across Scotland, Wales and Northern Ireland.

Scotland has a key role to play in the development of a UK hydrogen economy, with the potential to produce industrial-scale quantities of hydrogen from offshore and onshore wind resources, wave and tidal power, as well as with CCUS – supported by a strong company base and valuable skills and assets in oil and gas, offshore wind, and energy systems. Economic analysis for the Scottish Government suggests that Scotland could deliver 21-126TWh of hydrogen per year by 2045, with up to 96TWh of hydrogen for export to Europe and the rest of the UK in the most ambitious scenario, delivering significant jobs and local economic benefits.[12] The Scottish Government published a Hydrogen Policy Statement in December 2020, which set out their vision for the development of a hydrogen economy in Scotland and ambitions for renewable and low carbon hydrogen generation. A Hydrogen Action Plan will be published later this year, supported by a £100m programme of investment from 2021 to 2026.[13]

Scotland is home to a number of world-leading hydrogen demonstration projects that are helping determine the role that hydrogen could play in Scotland and the UK's future energy system. The European Marine Energy Centre in the Orkney Islands has a £65 million portfolio of renewable hydrogen projects that is still growing – providing a smaller-scale example of elements of a hydrogen economy (see case study below). Aberdeen is host

to 25 hydrogen double decker buses which have helped establish the infrastructure to support an ecosystem of over 60 hydrogen fuelled vehicles of many shapes and sizes – a catalyst for the Aberdeen Hydrogen Hub initiative, which seeks to become one of the key model hydrogen regions in Europe. The H100 neighbourhood trial project in Fife is building a 100 per cent electrolytic hydrogen production and distribution network and installing 300 homes with new hydrogen boilers to demonstrate hydrogen for domestic heating in the UK (see case study at Chapter 2.4.3). In March 2021, the UK and Scottish Government also outlined plans to each invest £50m as part of Heads of Terms for the Islands Growth Deal, to support the future economic prosperity of Orkney, Shetland and the Outer Hebrides, including several projects providing support for hydrogen.[14]

Orkney Islands: BIG HIT project

BIG HIT (Building Innovative Green Hydrogen Systems in Isolated Territories) is a six-year, Orkney based demonstration project which aims to create an integrated low carbon and localised energy system establishing a replicable model of hydrogen production, storage, distribution and use for heat, power and transport. Funded by the Fuel Cells and Hydrogen Joint Undertaking, the project builds on Orkney's Surf'n'Turf project – an innovative community renewable energy project using wind and tidal energy to produce hydrogen. State-of-the-art Proton Exchange Membrane (PEM) electrolysers in Eday and Shapinsay Islands produce hydrogen from electrolysis, using locally generated wind and tidal energy. This hydrogen is stored and used for heat, power and transport in the surrounding area. BIG HIT positions Orkney as an operational and replicable small scale Hydrogen Territory: the learning from BIG HIT will support wider replication and deployment of renewable energy with fuel cell & hydrogen technologies in isolated or constrained territories.

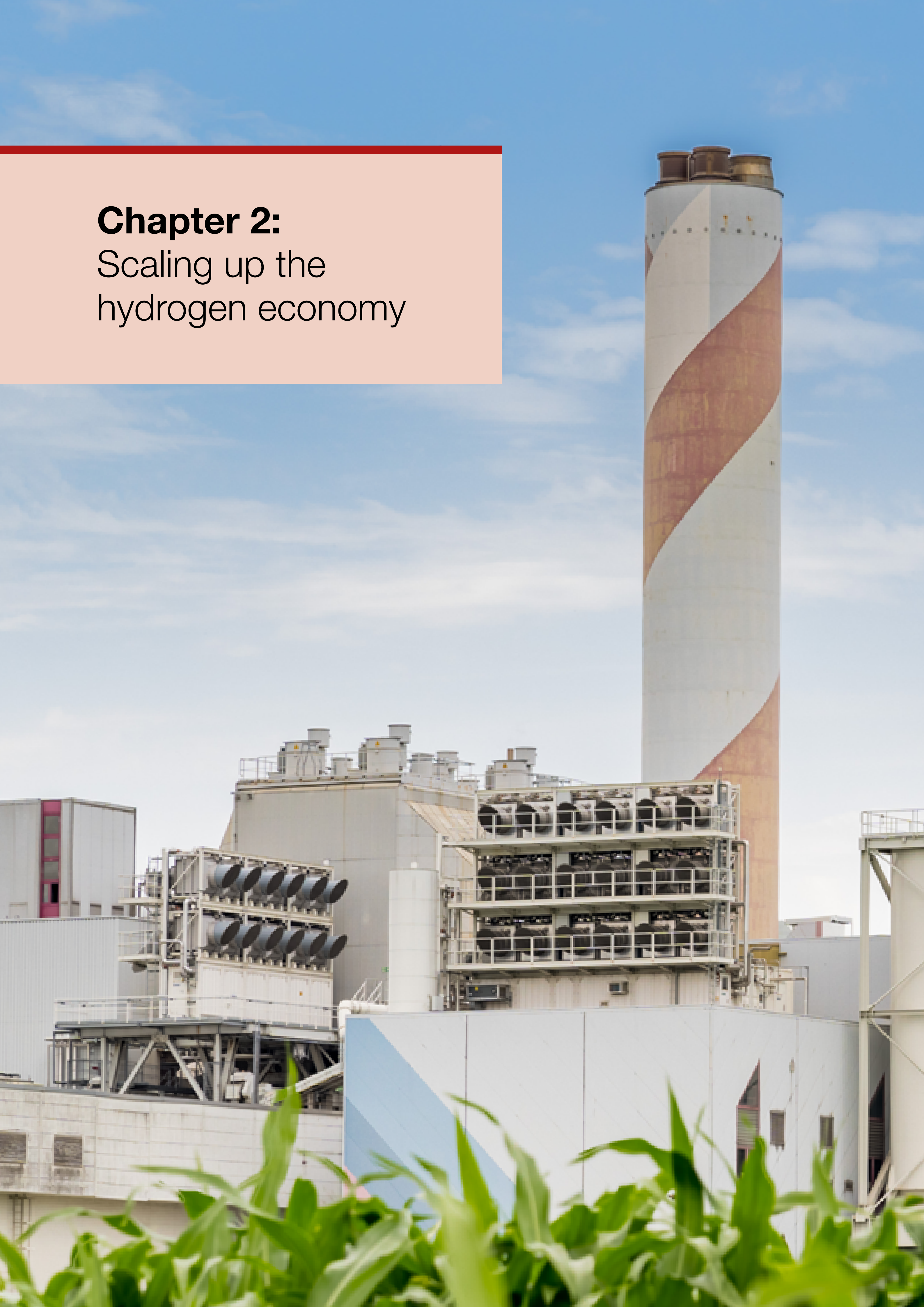
Wales has significant opportunities for low carbon hydrogen production and use. Its offshore wind and tidal and wave power potential, strong infrastructure networks and ports, research and development strengths, skills base and readily available internal markets provide a platform for deployment of hydrogen and fuel cell technologies under a favourable policy environment. The Welsh Government published a hydrogen pathway report in December 2020[15] and is now finalising its strategic position on hydrogen, which it will publish in early autumn 2021. A complementary Welsh Hydrogen Business Research and Innovation for Decarbonisation (H2BRID) initiative is also being developed for launch around the same time to support the challenges set by the Welsh hydrogen pathway and invest in innovative hydrogen projects across Wales.

Wales is home to several pioneering hydrogen companies, projects and research clusters. Welsh SME Riversimple is designing, building and testing innovative hydrogen fuel cell electric vehicles. The Dolphyn FLOW study is exploring the feasibility of a 100-300MW commercial hydrogen wind farm off South Wales, to be expanded in future, with hydrogen pipelines to strategic locations along the Milford Haven waterway for transport and heat applications, and potentially to Pembroke Dock for marine operations. The Hydrogen Centre, part of the Baglan Energy Park at Neath Port Talbot, is the focal point for a series of collaborative projects between the University of South Wales and other academic and industrial partners. The Centre focuses on experimental development of renewable hydrogen production and novel hydrogen energy storage, as well as further research and development of hydrogen vehicles, fuel cell applications and hydrogen energy systems. The UK Government also recently announced capital funding of up to £4.8m (subject to business case) for the Holyhead Hydrogen Hub, a demonstration hydrogen production plant and fuelling hub for HGVs to serve freight traffic at Holyhead and port-side vehicles, which could be operational by 2023.

Northern Ireland is likewise well-positioned to accelerate hydrogen innovation and deployment, with its significant wind resource, modern gas network, interconnection to Ireland and Great Britain, availability of salt cavern storage and strong reputation for engineering and manufacturing. Northern Ireland Water will be procuring a new electrolyser for one of its waste water treatment works – the first project of its kind in the UK. The public transport operator, Translink, is introducing new hydrogen buses built by local company Wrightbus in Ballymena and is procuring a new hydrogen fuelling station. The GenComm project led by Belfast Metropolitan College has received funding from both the EU and UK Government to trial hydrogen production via electrolysis for hydrogen buses. The Department for the Economy is currently consulting on policy options for a new Energy Strategy, including on hydrogen, which will set out Northern Ireland's energy focus and direction to 2050 and is expected to be published at the end of the year.

The UK Government is committed to working closely with the devolved administrations – including through the joint government-industry Hydrogen Advisory Council – to harness the UK's full potential to develop a world-leading hydrogen economy, and to make sure that low carbon hydrogen can contribute to emissions reduction and clean growth across the United Kingdom.

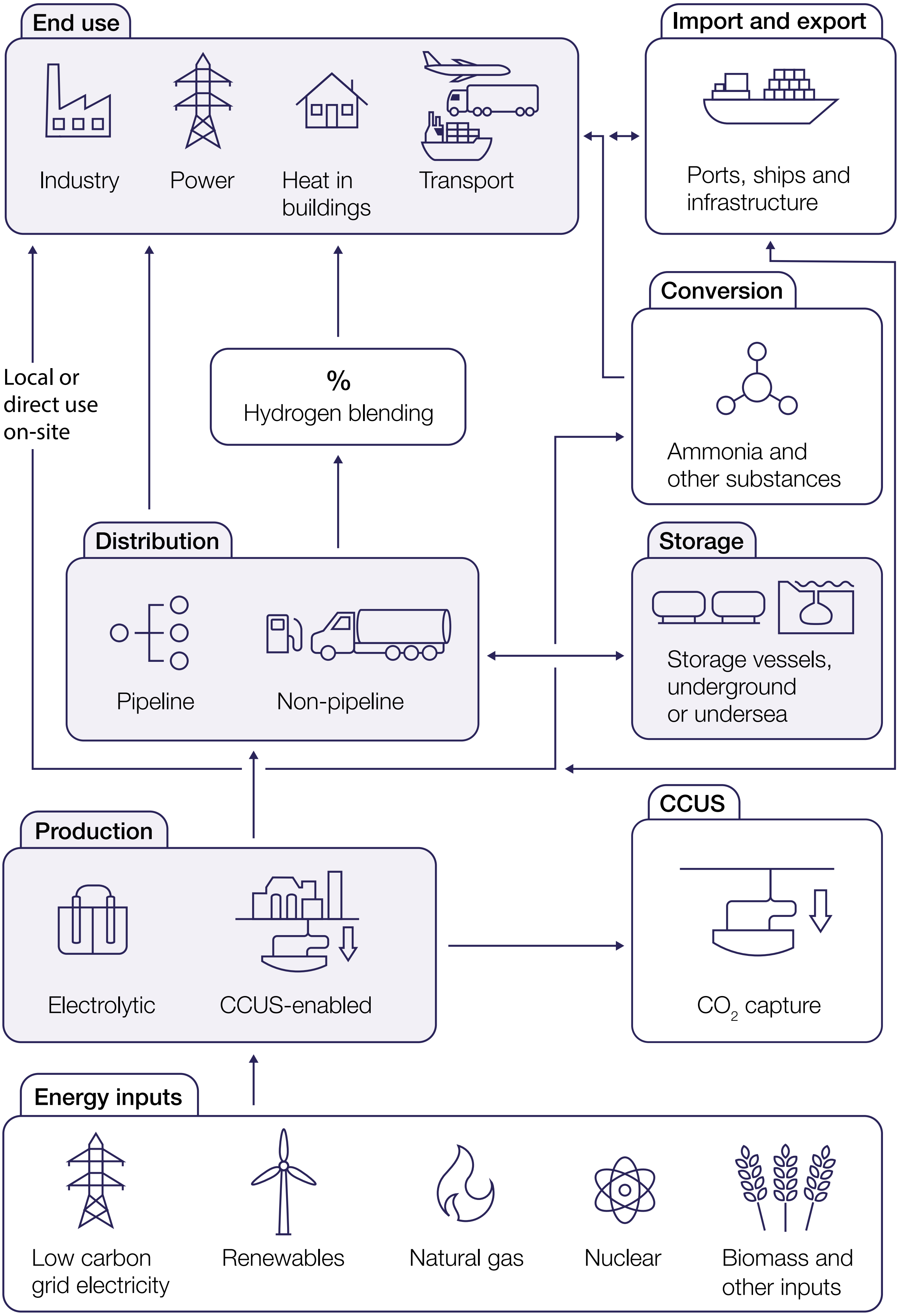
Chapter 2: Scaling up the hydrogen economy



Our ambition is clear, and the opportunities are great. Government cannot do it alone – we will need the collective efforts of industry, the research and innovation community and the UK public to be able to scale up the hydrogen economy over the coming decade to achieve our 2030 ambition. We know that action is needed across the entire hydrogen value chain in the 2020s to support commercial, technical and user readiness for new technologies and to create a thriving market for hydrogen and associated goods and services. The progress we make this decade will be crucial to pave the way for further scale up of production and use from 2030 so that hydrogen can contribute to achieving CB6 and net zero.

This chapter sets out government's whole-system approach to developing a UK hydrogen economy. It begins by outlining our 'roadmap' for the 2020s, our vision for how the hydrogen economy will develop and scale up over the course of the decade and into the 2030s, and how to enable this. The chapter then considers each part of the hydrogen value chain in detail and outlines the key steps that are needed to realise our 2030 ambition and position us for achieving our CB6 target. The chapter also sets out how we will create a thriving hydrogen market, supported by market and regulatory frameworks and with buy in and engagement from consumers and citizens. Further detail, including on demand by sector, factors influencing hydrogen supply mix, and analysis of the main barriers to hydrogen uptake across the value chain, is set out in our analytical annex.

Figure 2: The hydrogen value chain



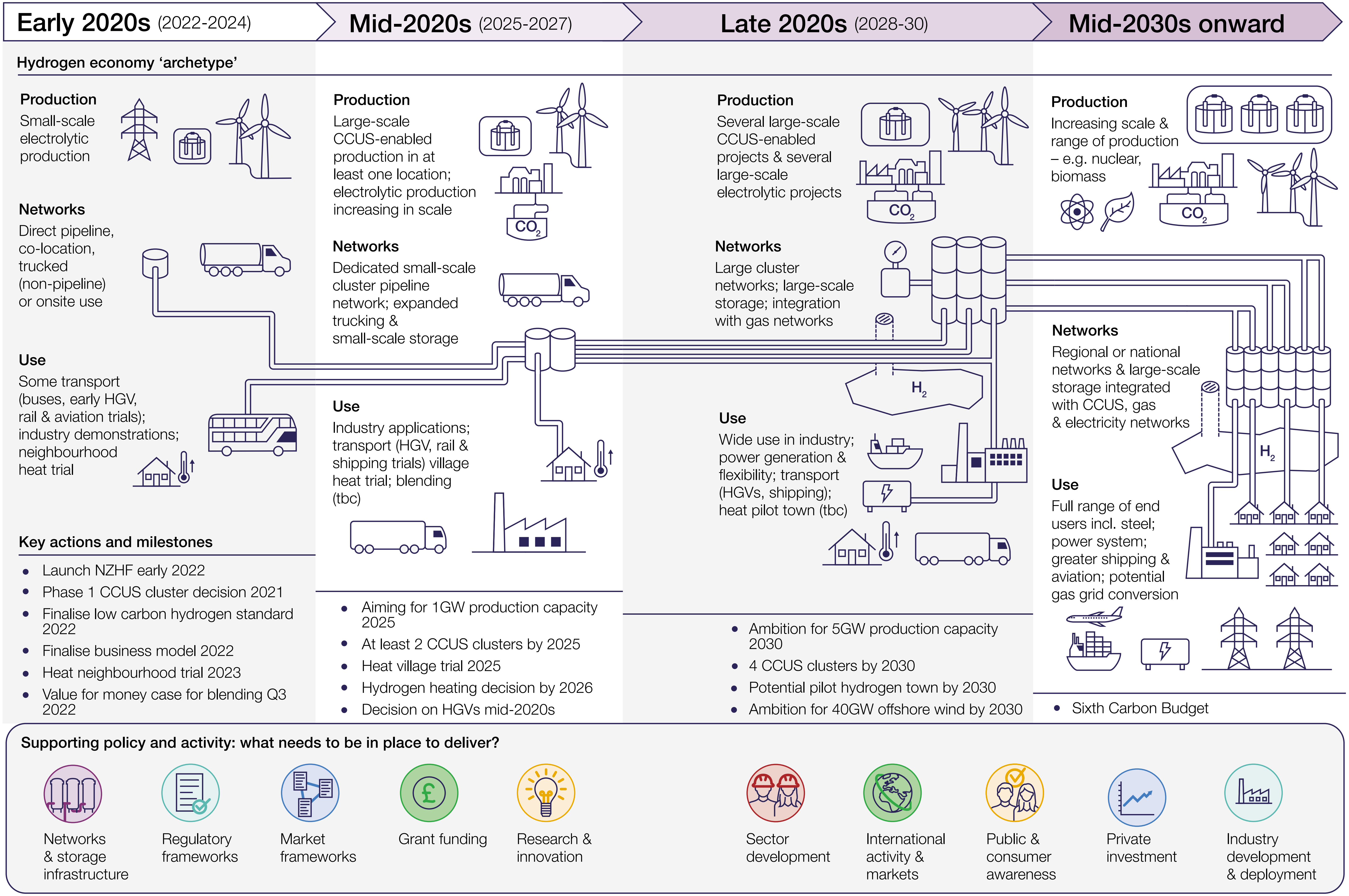
2.1 2020s Roadmap: a whole-system approach to developing a hydrogen economy

Our 2020s Roadmap (Figure 2.1 below) sets out our vision for how we expect the hydrogen economy will develop and scale up over the course of the decade, and what may be needed to enable this, framing the detail set out in the strategy. Developed in collaboration with industry through the Hydrogen Advisory Council, it is not a critical path, but is intended as a shared understanding and guide for what government and industry need to do during the 2020s to deliver our 2030 ambition and position the hydrogen economy for ramp up beyond this for CB6 and net zero.

The roadmap takes a 'whole-system approach' to developing the hydrogen economy, setting out how government and industry need to coordinate and deliver activity across the value chain and supporting policy, and how this will evolve over time. This will help bring forward early projects to build out the supply chain and enable learning by doing, while establishing the longer-term frameworks needed to develop a mature, competitive hydrogen economy and capture the resulting economic opportunities for the UK.

The roadmap is based around archetypes of a hydrogen economy we would expect to see in the early 2020s, mid-2020s and late 2020s, as well as by the mid-2030s for CB6. For each archetype, it sets out what supporting policies or activities need to be in place to deliver, with further detailed actions and commitments set out in the rest of the strategy. This roadmap and further detail offers a blueprint for implementation which will guide our work over the coming months and years.

Figure 2.1: Hydrogen economy 2020s Roadmap



Supporting policy and activity: what needs to be in place to deliver?

	Early 2020s (2021-2024)	**Mid-2020s** (2025-2027)
Networks & storage infrastructure	Pipeline/ non pipeline/ co-location infrastructure in place Storage requirement and type(s) established for range of pathways (clusters, heat, power system) Decentralised storage in place	Dedicated networks in place/ repurposed, expanded trucking & necessary centralised storage in place Links in place with existing gas, & electricity & new CCUS networks Future of gas grid decision, informing future network/ storage infrastructure development
Regulatory frameworks	Networks delivered through existing regulatory and legal framework Regulatory signals (e.g. H_2 readiness) in place Wider standards (e,g. safety and purity) updated/in place Critical first-of-a-kind deployment barriers addressed Planning and permitting regimes in place	Initial network regulatory and legal framework in place including potentially blending Initial system operation in place Further deployment barriers addressed – purity, installation, equipment Gas billing methodology in place
Market frameworks	Hydrogen business model (BM) finalised and in place Wider market framework structures and implications for BM understood Low carbon hydrogen standard in place Revenue support (RTFO) in place for transport sector	Dedicated revenue support framework, financial arrangements & wider market frameworks in place and driving private investment Market framework aligned to wider energy system frameworks Hydrogen potentially blended into existing gas grid
Grant funding	Capital grant funding mechanisms in place driving investment across production, as well as end use e.g. industry, transport	Capital grant funding supporting investment & project delivery alongside revenue support
Research & innovation	Programmes in place coordinating effort, support & de-risking/ demos for production, industry, transport, storage, heating R&I ecosystems in place supporting supply chain development	Programmes in place & de-risking of less developed technologies for late 2020s/30s Questions addressed as technologies developed & deployed

Supporting policy and activity: what needs to be in place to deliver?

	Late 2020s (2028-2030)	**Mid-2030s onward**
Networks & storage infrastructure	Large dedicated networks & storage in place (new or repurposed)	Regional & potentially national distribution networks in place Multiple storage sites in place Import/export infrastructure in place
Regulatory frameworks	Long-term regulatory and legal framework and role for regulation in place to support network expansion Long term system operator(s) in place Necessary regulations, codes and standards addressed and in place	Framework in place enabling cross-border pipeline/ shipping trade Regulatory framework adapted as market matures
Market frameworks	Long-term market frameworks, financial arrangements & market design in place	Competitive open market in place including path to subsidy free production and use
Grant funding	Possible role for capital grant funding supporting investment & project delivery alongside revenue support	Competitive market drives bulk of private sector investment
Research & innovation	Programmes support and accelerate next generation technology development	Well-established R&I ecosystem continues to drive forward technological advances

Supporting policy and activity: what needs to be in place to deliver?

	Early 2020s (2021-2024)	**Mid-2020s** (2025-2027)
Sector development	Sector & government work to develop UK supply chains & skills base	Framework in place to support supply chain & skills development, maximising value to UK Plc.
International activity & markets	Key technology & regulatory barriers identified through coordinated effort/ info sharing Early progress made on technology innovation & cost reduction, standards & policy/ regulatory coordination	Coordinated innovation, policy & regulation delivering accelerated deployment across value chain in key markets
Public & consumer awareness	Critical end user consumer barriers understood e.g. heat, industry Civil society & regional stakeholders & community priorities understood	End user consumer barriers addressed for early projects Civil society, regional stakeholders fully engaged
Private investment	FEED and FID secured for early 2020s projects Strategic partnerships with key organisations in place Private investment secured for small scale projects Private capital for innovation in place Financial sector engaged on hydrogen	FEED & FID secured for large-scale CCUS enabled/ mid 2020s projects Private investment and financial arrangements secured unlocking deployment Private investment in demonstration/innovation Investment in workforce – training, resourcing
Industry development & deployment	Industry led technology development & testing across value chain (including with government support) Government engaged, including through formal consultation Consumers engaged including communities local to key hydrogen projects / participating in hydrogen trials Early 2020s projects constructed	Continued technology development & testing across value chain to enable wider range of applications & less developed technology Demand for projects secured & necessary enabling infrastructure Leading larger scale on/off cluster projects developed – industry, power, transport, potentially blending Mid 2020s projects constructed

Supporting policy and activity: what needs to be in place to deliver?

	Late 2020s (2028-2030)	**Mid-2030s onward**
Sector development	UK supply chains & skills base well positioned to support increased deployment & exports of technology, expertise & potentially hydrogen	UK supply chains & skills base capitalise on accelerated UK/ global deployment through exports of technology, expertise & hydrogen
International activity & markets	Significant cost reduction & commercialisation driving deployment across multiple markets Framework to facilitate cross border-trade finalised	Framework for international hydrogen trade and competitive open market in place
Public & consumer awareness	Consumer acceptance secured across end use sectors Widespread support secured for hydrogen	Hydrogen widely accepted as a decarbonised energy source
Private investment	FEED and FID secured for large-scale electrolytic/late 2020s projects Private sector investment in manufacturing facilities aligned to UK sector development opportunities New market entrants as market framework demonstrated	FEED and FID secured for 2030s projects Private investment drives hydrogen economy expansion New market entrants & business opportunities secured
Industry development & deployment	Project partnerships in place to secure benefits of shared infrastructure Second phase on-cluster projects & new small-/ medium-scale projects Late 2020s projects constructed	Post 2030 development & testing delivered New projects cluster/off cluster constructed and existing expanded

2.2 Hydrogen production

Key commitments

- Ambition for **5GW of low carbon hydrogen production capacity by 2030**.
- We will launch the **£240m Net Zero Hydrogen Fund** in early 2022 for co-investment in early hydrogen production projects.
- We will deliver the **£60 million Low Carbon Hydrogen Supply 2** competition.
- We will finalise design of **UK standard for low carbon hydrogen** by early 2022.
- We will finalise **Hydrogen Business Model** in 2022, enabling first contracts to be allocated from Q1 2023.
- We will provide further detail on our **production strategy and twin track approach** by early 2022.

There are a variety of different ways to produce hydrogen; whether this hydrogen is low carbon or not depends on the energy inputs and technologies used throughout this process. Current hydrogen production in the UK is almost all derived from fossil fuels, using steam methane reformation from natural gas without capturing and storing any of the resulting carbon emissions. At present an estimated 10-27TWh[16] of hydrogen is produced in the UK, mostly for use in the petrochemical sector. There is currently only a very small amount of electrolytic hydrogen production in the UK, mostly for use in localised transport projects or trials for different uses of hydrogen, such as blending into the gas grid.[17]

As we scale up low carbon production through the 2020s, we expect the main production methods to be steam methane reformation with carbon capture, and electrolytic hydrogen predominantly powered by renewables. But these are not the only methods that could play a role in our future energy mix.

The main hydrogen production methods expected to be deployed in the 2020s, and some methods currently under development that could play a role in the future, are included in Table 2.2 below. Further detail is included in the analytical annex and report on Low Carbon Hydrogen Standards published alongside this strategy.

Table 2.2: Overview of selected hydrogen production methods

Production method	Definition	Carbon Intensity estimates[18]	Levelised Costs[19]	Role to 2030 / 2050	Next steps
Steam methane reformation without carbon capture	Natural gas with methane reformation, mostly for use in petro-chemical sector	83.6 $gCO_2e/MJ\ H_2$ (LHV)	SMR (300MW) 2020: £64/MWh 2050: £130/MWh	Small amounts of existing supply have helped prove end use case in tests / trials.	Decarbonise existing use in industry
Steam methane reformation (SMR) or autothermal reformation (ATR) with carbon capture	Natural gas with methane reformation, but with CO2 emissions captured and stored or reused	ATR with CCS: 16.0 $gCO_2e/MJ\ H_2$ (LHV) SMR with CCS: 21.4 $gCO_2e/MJ\ H_2$ (LHV)	ATR (300MW): 2020: £62/MWh 2050: £65/MWh SMR (300MW): 2020: £59/MWh 2050: £67/MWh	Large scale projects expected from mid-2020s, bulk supply to kick start UK hydrogen economy	Carbon capture and storage infrastructure needs to be in place
Grid electrolysis	Using electricity from the grid to electrolyse water, splitting it into hydrogen and oxygen.	78.4 $gCO_2e/MJ\ H_2$ (note this is a blended figure using grid averages to calculate)	PEM (10MW): 2020: £197/MWh 2050: £155/MWh	To be determined based on further policy development	Further engagement and analysis required, e.g. via the consultation on the UK Low Carbon Hydrogen Standard
Renewable electrolysis	Using clean electricity to electrolyse water, splitting it into hydrogen and oxygen	0.1 $gCO_2e/MJ\ H_2$ (LHV)	PEM (10MW) (with dedicated offshore wind): 2025: £112/MWh 2050: £71/MWh	Small projects expected to be ready to build in early 2020s	Scale up technology, reduce costs over time

Production method	Definition	Carbon Intensity estimates[18]	Levelised Costs[19]	Role to 2030 / 2050	Next steps
Low temperature nuclear electrolysis	Low temperature electrolysis from existing nuclear facilities	Not modelled but expected low GHG emissions.	Not modelled by BEIS	Can apply existing technologies to current plants in the 2020s.	Further developments expected in 2020s.
High temperature nuclear electrolysis	High temperature nuclear power to electrolyse water	High temperature electrolysis: 4.8 $gCO_2e/MJ\ H_2$ (LHV)	Not modelled by BEIS	Could develop hydrogen from advanced nuclear for 2030s	Further innovation and developments expected in 2020s.
Bioenergy with carbon capture and storage (BECCS)	Biomass gasification with carbon capture and storage	-168.7 $gCO_2e/MJ\ H_2$ (LHV)	BECCS (473MW) 2030: £95/MWh (excl. carbon) £41/MWh (incl. carbon) 2050: £89/MWh (excl. carbon) -£28/MWh (incl. carbon)	Could begin production in 2030s	Further innovation and developments expected in 2020s. Developing position further in forthcoming Biomass Strategy
Thermochemical water splitting	Direct splitting of water using very high temperature heat from advanced modular nuclear facilities	Not modelled but expected low GHG emissions.	Not modelled by BEIS	Could develop hydrogen from advanced nuclear for mid-late 2030s	Further innovation work to develop to commercial technology
Methane Pyrolysis	Heat splits natural gas into hydrogen and solid carbon	Not modelled, but expected low GHG emissions	Not modelled by BEIS	Nascent technology still to be proven at scale	R&D / Innovation

Working with industry, the UK's ambition is for 5GW of low carbon hydrogen production capacity by 2030. This ambition is based on our understanding of the pipeline of projects that could come forward during the 2020s, and takes into account the challenges, constraints and costs involved in delivering this. As we work towards this ambition, we would hope to see the first gigawatt of low carbon hydrogen production capacity in place by 2025. This is a fast-evolving market, however, and we will need to ensure we continue to develop our understanding as trends develop and policy decisions influence investments. We believe that working towards 5GW of production capacity by 2030 is a stretching but deliverable ambition, building on the UK's strong track record of delivering significant cost reductions and large-scale deployment of offshore wind and solar power, and will put us on a credible trajectory aligning with a pathway to net zero.[20] Achieving this ambition is a key outcome for our strategy and is expected to bring forward over £4 billion of private investment in the period up to 2030.

To meet this ambition, the UK has committed to a 'twin track' approach to hydrogen production, supporting both electrolytic and CCUS-enabled hydrogen, ensuring we support a variety of different production methods to deliver the level of hydrogen needed to meet net zero. This approach sets the UK apart, giving us a competitive advantage and building on our strengths to ensure we can be confident in delivering our 2030 ambition and beyond. As outlined in Chapter 1, the UK's skills, capabilities, assets, and infrastructure mean that we have the potential to excel in both electrolytic and CCUS-enabled low carbon hydrogen production. Supporting these and other potential production routes will enable us to develop low carbon hydrogen rapidly at scale while future-proofing our net zero ambitions.[21]

This twin-track approach has already underpinned successful innovation through our Low Carbon Hydrogen Supply Competition, which set out to support development and cost reduction of a wide range of world-leading technologies. This has supported projects including methane reformers with higher carbon capture rates, scaling up of modules and support for the automated manufacture of electrolysers, and work to evidence the feasibility of electrolysis from low carbon nuclear.

As set out in the analytical annex published alongside this strategy, the proportion of hydrogen which will be supplied by particular technologies depends on a range of assumptions, which can only be tested through the market's reaction to the policies set out in this strategy and real, at-scale deployment of hydrogen across our complex energy system. Our Hydrogen Production Cost 2021 report suggests that, under central fuel price assumptions, CCUS-enabled methane reformation is currently the lowest cost low carbon hydrogen production technology. Given the potential production capacity of CCUS-enabled hydrogen plants, we would expect this route to be able to deliver a greater scale of hydrogen production as we look to establish a UK hydrogen economy during the 2020s. However, as referenced in Table 2.2 above, costs of electrolytic hydrogen are expected to decrease considerably over time, and in some cases could become cost-competitive with CCUS-enabled methane reformation as early as 2025. Given the range of uncertainties and variable assumptions in this area, and the rapid growth we need to meet our carbon budgets, we consider support for multiple production routes the most appropriate approach, rather than reliance on a single technology pathway.

How will we develop and scale up low carbon hydrogen production over the 2020s?

Our commitment to supporting multiple production routes will, we believe, bring forward the broad range of projects needed to ensure a rapid and cost-effective build out of the hydrogen economy. Greater competition will spur innovation, cost reductions and investment across the value chain. Deploying CCUS-enabled hydrogen capacity will achieve cost-effective near-term low carbon hydrogen production at scale, drive investment across the value chain (including transmission, distribution and storage), and pull a range of hydrogen technologies through to commercialisation. Alongside this, supporting the scale up of electrolytic hydrogen production can drive down costs to establish a cost-optimal and credible technology mix for our pathway to net zero. Our focus will be on promoting domestic production and supply chains, although we would expect to be an active participant in international markets as they develop, maximising export opportunities and utilising import opportunities as appropriate.

The first movers in the early 2020s are likely to be relatively small (up to 20MW) electrolytic hydrogen projects that can be deployed at pace, with production and end use closely linked, for example, at a transport depot or industrial site. By the mid-2020s we could start seeing larger (100MW) electrolytic hydrogen projects and the first CCUS-enabled hydrogen production facilities based in industrial clusters. At this stage producers could be catering for a growing range of customers across transport, industry and power generation as well as potential to supply hydrogen heat trials and blend low carbon hydrogen into the gas grid. By the end of the decade we could have multiple large CCUS-enabled (500MW+) production facilities across the UK, with extensive cluster networks and integration into the wider energy system. Achieving our 2030 ambition is expected to provide up to 42TWh of low carbon hydrogen for use across the economy.

Case study: ITM Power – electrolytic hydrogen production

Based in Sheffield, ITM Power are a world-leading manufacturer of PEM (proton exchange membrane) electrolysers, a technology for hydrogen production from water. The company's new Gigafactory is the world's largest electrolyser factory with a 1GW per annum capacity to produce renewable hydrogen for transport, heat and chemicals. In May 2020, ITM Power announced plans to establish a separate subsidiary – ITM Motive – to build, own and operate eight publicly accessible H_2 refuelling stations.

Several ITM projects are supported by government. The company's Gigastack project – led alongside Ørsted, Phillips 66 Limited and Element Energy – won funding from BEIS' Low Carbon Hydrogen Supply Competition. Gigastack is developing electrolyser technology to produce renewable hydrogen at industrial scale.

The exact production mix by 2030 will be influenced by a range of factors, such as carbon pricing and the policies being consulted on in parallel to this strategy. Alongside this, investor confidence and market forces will dictate the type of projects that will come forward during the 2020s. In the longer term, electrolytic hydrogen offers greater carbon reduction potential and cost reductions, making it cost-competitive with CCUS-enabled

hydrogen over time.[22] Using the 2020s to 'learn by doing', supported by research and innovation, will provide lead-in time needed to enable commercial production of electrolytic hydrogen at larger scale from the 2030s onwards, ensuring it can plug into a wider hydrogen value chain commercialised through large scale CCUS-enabled production.

Investors, developers and companies across the length and breadth of the UK are ready to build if the right policy environment is in place. We are aware of a potential pipeline of over 15GW of projects, from large scale CCUS-enabled production plants in our industrial heartlands, to wind or solar powered electrolysers in every corner of the UK. This includes plans for over 1GW of electrolytic hydrogen projects, ranging from concept stage to fully developed proposals, which are aiming to deploy in the early 2020s. Other production methods being proposed by industry include using biomethane or the electricity or heat from a nuclear reactor as energy inputs to hydrogen production.

Case study: Acorn Project – CCUS-enabled hydrogen production

Led by Pale Blue Dot Energy, the Acorn CCS and Hydrogen Project in St Fergus, Scotland (image left), aims to deliver an energy- and cost-effective process for low carbon hydrogen production for use in a range of applications including industrial fuel switching and decarbonising heating. The project, supported through BEIS' Low Carbon Hydrogen Supply Competition, conducted engineering studies to evaluate and develop the advanced reformation process, including assessment of Johnson Matthey's low carbon hydrogen technology and an alternative reformer technology.

From the 2030s onwards, we may see a wider range of production technologies coming to the market including more hydrogen from nuclear, using low carbon heat and power from small modular and advanced modular reactors, as well as bio-hydrogen with CCUS that can deliver negative emissions. A dynamic market will include multiple sources and end uses for hydrogen.

To meet our CB6 and net zero targets, there is likely to be a substantial ramp up in demand beyond 2030. Our analysis suggests that hydrogen demand could increase significantly in the early 2030s, suggesting 7-20GW of production capacity may be needed by 2035.[23] Demand could continue to increase rapidly over the 2030s and 2040s, requiring a corresponding increase in hydrogen production capacity to ensure there is sufficient supply to meet this.

In achieving our 2030 5GW ambition and delivering production levels needed for CB6 and net zero, we will have to work with industry and other stakeholders to better understand and overcome the barriers to growing a new energy vector for the UK. These barriers reflect the strategic challenges outlined in Chapter 1.5 and include:

- High production cost relative to high-carbon fuel alternatives.
- High technological and commercial risks for maintaining operation of first-of-a-kind projects and investment in next-of-a-kind deployment.
- Demand uncertainty due to current limited use of low carbon hydrogen in the UK.
- Lack of market structure, small number of end users potentially leading to the abuse of market power.
- Distribution and storage barriers, reflecting the current lack of sufficient carbon capture and storage and hydrogen transmission infrastructure.
- Policy and regulatory uncertainty, including the lack of established standards to define low carbon hydrogen (including non-emission standards), and related to the limited understanding of the regulatory impacts of hydrogen at a system-wide level.

Detailed description of these barriers can be found in the analytical annex (chapter 2).

What are we doing to deliver new low carbon production?

This strategy marks a turning point for low carbon hydrogen production in the UK. It is part of a comprehensive package of measures, set out by government alongside the strategy and beyond, that can help deliver our 2030 5GW production ambition and ensure that we are ready for the step-change needed in low carbon hydrogen production in the 2030s to help meet our CB6 commitments and put us on a pathway to net zero:

- **Research and innovation:** The UK is already at the forefront of research and innovation across the hydrogen value chain, reducing technological, environmental, social and economic barriers to production and end use. **We also recently launched our £60 million Low Carbon Hydrogen Supply 2 Competition, which will develop novel hydrogen supply solutions for a growing hydrogen economy.**

- **CCUS infrastructure:** In November 2020 we confirmed allocation of £1 billion for the Carbon Capture and Storage (CCS) Infrastructure Fund, to help overcome carbon capture, distribution and storage barriers and enable the establishment of a new CCUS sector. **In May this year, we set out the details of the Carbon Capture, Usage and Storage (CCUS) Cluster Sequencing Process, which will look to identify at least two CCUS clusters for deployment in the mid-2020s.** Projects within the clusters will have the opportunity to be considered to receive any necessary support including access to the CCS Infrastructure Fund, and business models for transport and storage, power, industrial carbon capture and low carbon hydrogen.

- **Hydrogen Business Model:** In the Prime Minister's *Ten Point Plan*, we confirmed our intention to develop business models to help bring through investment in new low carbon hydrogen projects and help build UK capability to meet net zero. Since then, we have worked to develop a Hydrogen Business Model intended to provide long-term revenue support to hydrogen producers to overcome the cost challenge of producing low carbon hydrogen compared to cheaper high-carbon alternatives. We consider our preferred business model would provide an investable commercial framework for producers while also meeting government's objectives for developing the low-carbon hydrogen market and ensuring value for money. **Further detail on our proposals is set out in the** Hydrogen Business Model Consultation **published alongside this strategy. We intend to provide a response to this consultation alongside indicative Heads of Terms in Q1 2022.**

- **Net Zero Hydrogen Fund (NZHF):** As set out in the Prime Minister's *Ten Point Plan*, **the NZHF will provide up to £240 million of government co-investment to support new low carbon hydrogen production out to 2025, kickstarting efforts to deliver our 2030 5GW ambition.** The aim of the Fund is to support commercial deployment of new low carbon hydrogen production projects during the 2020s, helping to address barriers related to commercial risk and high production costs of hydrogen compared to fossil fuel alternatives. We are consulting on the design and delivery of the NZHF alongside the publication of this strategy, and **we intend to launch the NZHF in early 2022.**

- **Low Carbon Hydrogen Standard:** If we are to achieve our CB6 and net zero commitments, we must ensure that the hydrogen production we are supporting is sufficiently low carbon, while not stifling innovation and growth. To help address barriers related to policy and regulatory uncertainty, we have identified and assessed a series of options for a UK low carbon emissions standard that could underpin the deployment of low carbon hydrogen. Alongside this Strategy we have published a report, prepared for government by E4Tech and Ludwig-Bölkow-Systemtechnik (LBST), which explores a range of factors including maximum acceptable levels of greenhouse gas (GHG) emissions associated with low carbon hydrogen production and the methodology for calculating these GHG emissions. **Alongside this strategy, we have also published our consultation on a 'UK Low Carbon Hydrogen Standard', which seeks views on the options for setting and implementing such a standard, and we intend to finalise design elements of a UK standard for low carbon hydrogen by early 2022.**

Chapter 2.5 sets out a wider range of policy and regulatory levers which we are exploring to support the development of the hydrogen economy, including production.

Our future production strategy

In most of the pathways modelled by BEIS for CB6, hydrogen demand doubles between 2030 and 2035, and continues to increase rapidly over the 2030s and 2040s. By 2050, between 250-460TWh of hydrogen could be needed across the economy, delivering up to a third of final energy consumption.[24] Current analysis suggests that in 2050, hydrogen will be supplied through a mix of steam methane reformation with CCUS, electrolysis from renewable electricity, and biomass gasification with carbon capture and storage (BECCS), a position supported by the CCC's CB6 advice.[25]

As the hydrogen economy expands and demand grows, researchers, innovators, investors and producers will respond with new technological advances that could deliver further production cost reductions or greater emissions savings. The role for other production methods, including existing and future nuclear technologies, methane pyrolysis, and thermochemical water splitting, will need to be assessed and integrated into our modelling as appropriate to give us an evolving picture of our future production mix. As we increase our understanding of the project pipeline, and the measures needed to overcome barriers to widespread deployment of a range of production technologies, we can form a better picture of our future production strategy. In doing so, we will continue to consider the wider environmental impacts of different methods of hydrogen production, such as resource requirements for land or water, or any potential changes in soil, water or air quality. The production of hydrogen is likely to need significant amounts of water and, together with industry, we will continue engaging with the Environment Agency, regional water resources groups and water companies to ensure appropriate plans are in place for sustainable water resources.

During 2021 we will gather further evidence through our consultations on a Hydrogen Business Model, the NZHF and the standard for low carbon hydrogen, and undertake additional work on our production pathway in line with CB6. This will give us a better understanding of the mix of production technologies, how we will meet a ramp-up in demand, and the role that new technologies could play in achieving the levels of production necessary to meet our future CB6 and net zero commitments. **We will develop further detail on our hydrogen production strategy and twin track approach, including less developed production methods, by early 2022.**

2.3 Hydrogen networks and storage

Key commitments

- We will launch a **call for evidence on the future of the gas system** in 2021.
- We will **review systemic hydrogen network and storage requirements** in the 2020s and beyond, including need for economic regulation and funding, and provide an update in early 2022.
- We will deliver the **£68 million Longer Duration Energy Storage Demonstration** competition.
- We will deliver the **£60 million Low Carbon Hydrogen Supply 2** competition.

The development of network infrastructure to allow low carbon hydrogen to be transported to storage points and end users is central to the expansion of the hydrogen economy. Networks for the purposes of distributing hydrogen (hereafter hydrogen networks) will include a range of pipeline and non-pipeline channels (e.g. road and rail vehicles, marine vessels) which are crucial to ensuring hydrogen can reach a full range of end users, and be a truly strategic low carbon energy source in a net zero system.

Existing hydrogen production and use in the UK is currently on a small scale, and hydrogen tends to be produced and used in the same location. There is limited distribution through hydrogen pipelines, used to supply industrial users located in industrial clusters, as well as some transport of hydrogen by road into these hubs in either compressed gaseous or liquefied form. Alongside this, there is limited use of above ground metal storage tanks in industrial facilities.

We will need to see significant development and scale up of hydrogen network and storage infrastructure for the development of a UK hydrogen economy and for low carbon hydrogen is to play its role in supporting UK decarbonisation over the 2020s, under CB6 and on a pathway to net zero.

2.3.1 Networks – hydrogen transmission and distribution

How will hydrogen networks develop and scale up over the 2020s and beyond?

Hydrogen networks will have to grow and diversify considerably over the 2020s to enable the UK to meet its 2030 ambition and prepare for ramp up to CB6 and beyond. We expect growth to be driven by production and demand. This will impact the shape and location of the network, and whether it evolves into a national system or a number of regionally-based networks. This decade will see key policy decisions taken that will influence how hydrogen networks develop and are operated. Such decisions will need to consider interplay with existing oil and gas infrastructure, CO_2 transport and storage infrastructure, and electricity infrastructure.

Strategic decisions on blending hydrogen into the gas grid and hydrogen for heating will have a significant impact on the development of hydrogen networks. Blending may result in investments in equipment and infrastructure needed to support rollout in localised portions of the existing gas networks (see Chapter 2.5.1 for further details), and the decision on the use of hydrogen for heating (see Chapter 2.4.3) will impact the nature and scale of hydrogen network scale up, including whether and the extent to which parts of the gas grid are repurposed or decommissioned in the longer-term.

By the late 2020s and 2030, with the expansion of hydrogen production to several large-scale CCUS-enabled projects and electrolytic projects at a range of sizes, the hydrogen pipeline network may span tens of kilometres in length, supplying end-users either within cluster regions or more broadly. By the mid-2030s, the hydrogen network could serve multiple end use applications extending to tens to hundreds of kilometres, potentially including hydrogen converted and distributed as ammonia for use as a shipping fuel.

Internationally, countries are considering the need for dedicated hydrogen networks, alongside conversion of existing gas infrastructure. The potential for pan-European dedicated hydrogen transport infrastructure[26] and the use of existing or new gas interconnectors between the UK and Belgium, Netherlands and Ireland may enable the UK to trade hydrogen or low carbon gas with our neighbours in the future.

As larger cluster networks expand and we have more end users and larger scale storage development, we would expect all parts of the hydrogen economy to reach technology and market maturity by 2050, with potentially national-level distribution.

How are we approaching the task?

There are several interrelated issues which we will need to consider in developing networks that can fulfil hydrogen's potential as a key enabler in decarbonising the UK energy system.

While we expect the initial growth in networks to be driven by the market and the needs of specific privately-operated projects, we believe *it will be important that initial investments and later evolution of the network are achieved in a coordinated manner*, which manages investment risks and delivers benefits to consumers while delivering our 2030 ambition and positioning the hydrogen economy for significant expected growth beyond this. We will need to consider whether and what policy mechanisms, such as incentives or regulation, are needed to ensure that network infrastructure is developed to allow later build out and interlinkages. We will also need to manage or mitigate the risk of stranded assets if pipelines developed for initial projects in the 2020s are not fit for purpose in the 2030s.

Issues around *whether and how to fund hydrogen networks* need to be considered, accounting for variables such as length of pipe, number of producers and end users, and capacity of pipe for future development. Funding considerations are likely to be different for different sizes and types of projects – for example, small scale early pipelines using new or connecting to existing small-scale infrastructure versus large scale pipelines which connect to larger network infrastructure, either new or repurposed from existing networks.

We will need to consider the *type of commercial frameworks and ownership structures* needed for end-to-end pipelines and for wider networks with many suppliers and end users. This will be particularly important when thinking about whether early commercial arrangements for the production and distribution of hydrogen will be sufficient to enable scale up of the hydrogen economy in the later 2020s, or whether changes are needed to support this. Issues related to regulating third-party access to infrastructure, monopolies and unbundling will need to be resolved to provide clarity to investors.

Decisions on where *CCUS infrastructure* will be installed will impact the development of networks for CCUS-enabled hydrogen production and vice-versa. These two policy areas will need to be co-developed to ensure optimum outcomes in both areas are achieved.

Decisions on heat and on the future of the existing gas network will have a significant impact on the size and design of hydrogen networks. While there may be efficiencies in repurposing parts of the gas network, this may not be appropriate for all parts of the country or for all end users.

We expect some *non-pipeline distribution* for areas without pipeline connections to emerge over the 2020s through trucks and other road transport, which could enable further use of hydrogen beyond production centres. We will need to understand the existing regulatory context for non-pipeline distribution and whether it is fit for purpose in an expanded hydrogen economy, as well as whether funding support would be needed.

What are we doing to deliver?

We recognise the need to put in place clear policies and supportive regulatory regimes and to build consumer acceptance to rapidly develop and deploy hydrogen networks.

There is already a range of work ongoing to explore the development of hydrogen networks. A variety of joint government and industry research, development and testing projects are underway, designed to help determine the safety, feasibility, costs and benefits of converting the existing gas grid to carry 100 per cent hydrogen (see Chapter 2.4.3). This includes identifying and characterising the possible options to transition the gas grid, including repurposing the existing grid, building new networks, or transitioning parts of the grid. This work will support strategic decisions in the mid-2020s on the role of hydrogen for heating and linkages with the existing gas grid. Other projects, such as those set out below, will also help inform the evidence base for developing hydrogen network infrastructure. **We will continue to support such research, development and testing projects to explore development of hydrogen network infrastructure.**

Exploring hydrogen network infrastructure

Project Union explores the development of a UK hydrogen network which would join industrial clusters around the country, potentially spanning 2000km. This National Grid project would repurpose around 25 per cent of the current gas transmission pipelines and could carry at least a quarter of the UK's current gas demand. The feasibility stage of the project is using net zero development funding to identify pipeline routes, assess the readiness of existing gas assets, and determine a transition plan for assets. The research will also explore how National Grid can start to convert pipelines in a phased approach from 2026.

H21 is a series of industry-led projects funded by Ofgem which test pure hydrogen in pipelines and connecting infrastructure to build the evidence base for hydrogen transport in dedicated pipelines. The findings from these programmes are being used to establish frameworks for pipeline safety which will be appraised by the HSE's Science Division, and help inform government's strategic decision on the longer-term role of hydrogen for heat by the mid-2020s (see Chapter 2.4.3).

FutureGrid aims to create a representative transmission network to trial hydrogen. The network will be built from a range of decommissioned transmission assets and will allow for real-time testing and analysis of the network in operation. Blends of hydrogen up to 100 per cent will be tested at transmission pressures to assess how the re-purposed assets perform, with construction to launch this year and testing in 2022. FutureGrid will connect to Northern Gas Network's existing H21 distribution network facility and the HyStreet homes to demonstrate that a complete 'beach-to-meter' network can be decarbonised. This £12.7million National Grid project is largely funded through Ofgem's Network Innovation Competition (£9.1 million) with the remaining amount from project partners. To allow testing to be undertaken in a controlled environment with no risk to the safety and reliability of the existing gas transmission network, the hydrogen research facility will remain separate from the main National Transmission System.

Future Billing Methodology is a Cadent Gas project to explore a range of different options for future gas billing to prepare for potential changes to gas blends. Future consumer gas billing methodologies will need to reflect the differences in calorific value between methane, biomethane and hydrogen to enable blending of these gases into the existing grid.

The Iron Mains Risk Reduction Programme decommissions gas distribution iron mains and replaces them with new plastic ones, which are potentially well-suited for transporting hydrogen within the existing gas grid over the long term. This project was introduced in 2002 and is regulated by the HSE.

We will also consider whether the costs of small-scale distribution infrastructure and connecting to existing networks operated by third parties could be factored into overall project costs of production under the proposed hydrogen business model. We expect that this model is unlikely to be appropriate for large scale projects or pipelines which form part of a larger network infrastructure, and we will need to explore whether funding for these larger projects is appropriate and what that might look like. **We will use the Hydrogen Business Model Consultation published alongside this strategy to seek views on a limited number of questions which will feed into the design of the business model and the hydrogen network review set out below.**

Beyond testing and evidence-building, we anticipate that work to explore investment signals and necessary amendments to legislation, regulatory frameworks and potential access to financing for hydrogen network projects in the early 2020s and the 2030s will be required. This will need to address issues such as:

- Uncertainties around the permitting procedures (and accompanying regulations) for new hydrogen pipeline infrastructure, which could be located in hydrogen supply hubs initially before wider network expansion.
- Potential need to further harmonise regulations between new hydrogen pipelines in clusters and existing hydrogen pipelines.
- How to provide sufficient flexibility for any future regulation of end use applications involving domestic consumers such as heating.

In the 2020s, we will seek to ensure that an appropriate legislative framework is in place to incentivise investment in resilient, efficient infrastructure, which integrates low carbon energy solutions over time. As part of this, **we will review the overarching market framework set out in the Gas Act 1986 to ensure appropriate powers and responsibilities are in place to facilitate a decarbonised gas future. We are also reviewing gas quality standards with a view to enabling the existing gas network to have access to a wider range of gases.** This will potentially include hydrogen, subject to hydrogen blending trials proving successful.

We will launch a Call for Evidence on the future of the gas system this year. Amongst other things, the Call for Evidence will look at the current gas types, including implications for a potential increased use of hydrogen in the system, and will seek to include questions on the potential role of hydrogen in the existing gas system. The outcome of the Call for Evidence should draw out expertise on gas across the energy sector, gather views from stakeholders and the public around the future role of gas in meeting our net zero target, highlight concerns that need to be addressed, including risks and barriers, and collect evidence on work currently being done by industry on the future role of the gas system that focuses on the net zero ambition.

We recognise the need for further detailed work to establish the policy approach for the development of hydrogen network infrastructure and the decisions to be taken over the course of the 2020s. In doing so, we will seek to identify where decisions and action can be taken quickly so as not to stifle progress driven by the market. We will work with key stakeholders including producers, network operators, regulators, local authorities and end users to consider the trade-offs between different models for the expansion and diversification of hydrogen networks, while taking into account a range of related policy decisions such as decisions on decarbonising heat and use of hydrogen in transport.

Building on work already underway, **we will undertake a review of systemic hydrogen network requirements in the 2020s and beyond**, including: whether funding or other incentives are needed; introduction of regulation specific to hydrogen networks; resilience and future-proofing ahead of potential regional and national networks; and interaction with wider networks including CCUS,[27] gas and electricity. We will develop policy in this area in several ways, including through discussion and consultation with the Hydrogen Advisory Council and its working groups, and the Hydrogen Business Model consultation published alongside this strategy. While we recognise that there is important learning to be drawn from existing regulatory models and the technical assessments that are being progressed by incumbent parties, we will not make assumptions about who owns and operates hydrogen pipelines, nor how these networks are governed, which will form part of the critical evidence appraisal. We will use the Hydrogen Business Model consultation to seek early views on some of these questions. **We will provide information on the status and outputs of this hydrogen network review in early 2022**.

2.3.2 Hydrogen storage

Hydrogen's ability to store energy for long periods of time and in large quantities is an important part of its strategic value to a fully decarbonised energy system, and we envisage hydrogen storage being a key part of future network infrastructure. Storage can support security of supply as production and use increase and become more spread over time and distance. Similarly, for a future energy system with a lot of intermittent renewable

power generation, hydrogen could be an important storage medium, converting excess renewable energy into a fuel for use across the economy, and supporting faster and greater integration of renewable capacity and the transition to a fully decarbonised power system (see Chapter 2.4.2).

There are a number of ways in which hydrogen can be stored:

- **Specialist tanks or storage vessels** can store MWh of energy, be stationary or mobile (such as tube trailers), and are purpose built using materials able to hold hydrogen at pressure.[28] These are already used in the chemicals industry and at hydrogen refuelling stations. Storage vessels have lower upfront costs than other methods, and are quicker to install or deploy; these may be attractive to projects seeking to balance their own supply and demand by storing lower volumes of hydrogen, or for use in areas without wider infrastructure, such as use of industrial non-road vehicles on construction sites.

- **Salt caverns (underground) storage** can store TWh of energy and are created by 'solution mining', where water is used to dissolve an underground space in a seam of rock salt, allowing hydrogen to be piped in and out. Hydrogen has been stored in caverns under Teesside since the 1970s,[29] and there is potential to repurpose caverns currently used for storing natural gas. The British Geological Survey suggests we have significant rock salt formations with potential for 1000s of terawatt hours of future storage.[30] Underground storage is able to provide large volume storage at lowest cost per unit of energy stored.[31] This is a significant strategic advantage for the UK compared to many other countries.

- **Depleted gas or oil fields (undersea) storage** while available in the UK, require further testing to be used for hydrogen. We will also need to consider competing storage demands, notably for CO_2, in these fields.

- **Hydrogen carriers (ammonia (NH_3), liquid organic hydrogen carriers (LOHCs, such as toluene), cryogenic liquid, substances such as metal hydrides)** provide a route to store energy from hydrogen at increased energy density. These storage methods may become more widely used as research and innovation reduces associated costs, complexity and efficiency losses.

Hydrogen storage in a net zero energy system

Storage can support the hydrogen economy in a range of ways that position it as a strategic asset not just for hydrogen, but as part of a fully decarbonised, net zero economy by 2050.

Most hydrogen today is produced and used directly in industrial processes, often with one operator overseeing both operations, largely removing the need for storage. However, as hydrogen takes on a wider role across the energy system and production methods evolve, storage may become more important to allow balancing within larger projects and to enable the hydrogen economy to develop in the most technically and economically efficient way, helping to manage swings in demand and supporting the transfer of energy across sectors and time.

Storage may be more important for hydrogen than it is today for natural gas because there are no natural reserves of hydrogen that can be relied upon at times of high demand. Hydrogen has to be manufactured, and there are optimal ways of doing so, including maintaining steady production across time. Storage can support this.

Storage could help the early development of the hydrogen economy where demand takes time to build or if there is change in the profile and nature of off-takers. Over time, should we see large scale use of hydrogen in heat, strategic underground storage would be highly valuable in meeting seasonal demand variations, and as discussed above, it may play an important role in smoothing the intermittency of renewable energy.

National Grid's 'Future Energy Scenarios 2021' suggest that between 12TWh and 51TWh of hydrogen storage will be required in 2050 across varying net zero compliant scenarios.[32] Similarly, Aurora Energy Research's 'Hydrogen for a Net Zero GB' report concludes that 19TWh of centralised salt cavern storage might be required by 2050.[33] The UK currently has seven salt caverns and depleted gas fields being used as active natural gas storage facilities, providing approximately 1.5 billion cubic meters, or 14.5TWh, of storage capacity.[34] Although some of this could be repurposed for hydrogen storage, providing the same level of energy storage as hydrogen would require greater capacity given that hydrogen has only a third the energy density of natural gas.

How will hydrogen storage scale up in the 2020s?

In the early 2020s, hydrogen storage vessels are likely to be the most common storage option, used for example at hydrogen refuelling stations coupled to electrolytic hydrogen production. In the mid-2020s, CCUS-enabled production for industrial fuel switching is likely to be designed to minimise supply-demand variations, as is the case on clusters today. Proposed cluster projects in development such as HyNet North West[35] and Zero Carbon Humber have identified local large scale underground storage options but these appear to be secondary phase needs.[36]

Case study: SSE Thermal and Equinor hydrogen storage facility

SSE Thermal and Equinor are developing plans for one of the world's largest hydrogen storage facilities at Aldbrough on the East Yorkshire coast. The project partners believe the facility could be storing low carbon hydrogen as early as 2028. With an expected capacity of at least 320GWh in the first phase, Aldbrough Hydrogen Storage would be significantly larger than any hydrogen storage facility in operation in the world today. The existing Aldbrough Gas Storage facility commissioned in 2011 holds 40 per cent of the UK's gas storage capacity in its nine underground salt caverns, each roughly the size of St. Paul's Cathedral. Upgrading the site to store hydrogen would involve creating new caverns and/or converting the existing caverns.

The Aldbrough site is ideally located to store the low carbon hydrogen set to be produced and used in the Humber region, where Equinor and SSE Thermal are developing large-scale hydrogen projects as part of the Zero Carbon Humber partnership.

Equinor has announced its intention to develop 1.8GW of blue hydrogen production in the region, while the two project partners have plans to develop the world's first major 100 per cent hydrogen-fired power station by the end of the decade in Keadby, North Lincolnshire. The Aldbrough facility will initially store the hydrogen produced for the Keadby power station, and hopes to support and enable growing hydrogen ambitions across the region, supplying an expanding diverse off-taker market including power, heat, industry and transport throughout the late 2020s and 2030s.

By the late 2020s, a town-scale pilot of hydrogen heating and the potential for hydrogen in power generation could increase the necessity of large scale storage such that underground facilities start to become important. We may also see some initial volumes of hydrogen converted and stored as ammonia for use in shipping by the end of the decade, with increased scale up in the 2030s.[37]

Where early storage needs are limited to above ground storage vessels connected to specific production and use, we anticipate that projects could receive sufficient support from our proposed Hydrogen Business Model or the Renewable Transport Fuel Obligation to meet associated storage costs. However, as larger scale storage becomes required and the market develops, storage-specific revenue support could be needed.

Developing large-scale hydrogen storage, particularly as a strategic asset, will require overcoming significant challenges, in particular:

- Understanding the optimal need for, pace of development and mix of hydrogen storage technologies. This is dependent upon multiple factors, some of which are uncertain, such as routes to fully decarbonise power and heat.
- Long lead times and complexity in strategic scale storage such as salt caverns and depleted oil and gas fields. Salt caverns can take up to ten years to develop with challenges such as the need for environmentally appropriate disposal of brine. Repurposing depleted oil and gas fields will require understanding of demand for storage at scale and planned decommissioning dates if investment is to be made to extend the life of assets.
- Need for significant levels of investment, with salt caverns costing potentially hundreds of millions of pounds to develop. Further work is needed to understand the need for and potentially develop suitable funding mechanisms to support this.
- Further research and innovation to increase the efficiency for hydrogen storage, develop the viability of more energy dense options at a variety of scales, and understand the safety and environmental impacts of different storage options.

What are we doing to deliver?

Government is committed to supporting research and innovation to enable hydrogen storage to fulfil its potential in the future energy system. We have supported hydrogen storage through the £33 million Hydrogen Supply Competition,[38] provided UKRI funding to support innovation from industry such as Project Centurion[39] (a hydrogen salt cavern storage demonstration project), and are discussing proposals from industry to store hydrogen in depleted gas fields and storage facilities.

Building on these early developments, **we recently launched an expression of interest for the £60 million Low Carbon Hydrogen Supply 2 competition.**[40] Similar to the first competition in 2018, this is an innovation competition open to support a range of demonstration projects including hydrogen storage technologies, alongside wider hydrogen supply solutions. **We have also launched our £68 million Longer Duration Energy Storage Demonstration competition,**[41] which aims to accelerate commercialisation of innovative longer duration energy storage projects at different technology readiness levels. Storing hydrogen produced from excess electricity as a means of providing key flexibility services to the UK power grid is included within the scope of the proposal, subject to eligibility criteria.

More broadly, understanding the views of industry and developing our understanding of possible storage needs in different hydrogen scenarios over time will be key to realising the potential of hydrogen storage. We recently published a *Call for Evidence on facilitating the deployment of large-scale and long-duration electricity storage*[42] seeking views from industry on the barriers that electricity storage technologies face, including hydrogen where this is used in the power system.

To build on this evidence including beyond the electricity system, **we will undertake a review of systemic hydrogen storage requirements in the 2020s and beyond, including its potential role as a critical enabler for some end use sectors.** The review will consider whether funding or other incentives are needed, whether further government regulation might be required to ensure that the necessary storage infrastructure is available when needed, and what form this might take. Working with technology developers, regulators, and other stakeholders via the Hydrogen Advisory Council and other forums, and informed by our consultation activities, this work will inform future government policy on storage. In the meantime, **the Hydrogen Business Model consultation that accompanies this strategy includes specific questions on the treatment of small-scale storage within the Hydrogen Business Model, as well as on the potential need for government intervention to facilitate investment in future larger scale storage.** Answers to these questions will help inform our storage review. **We will provide information on status and outputs of this review in early 2022, to facilitate further discussion with stakeholders.**

There is still much work to do to understand, develop and scale up the network and storage infrastructure required to support a thriving UK hydrogen economy and position hydrogen to support the wider decarbonisation of the energy system by the end of the decade. Getting it right will be help deliver our 2030 production ambition and contribute to emissions reduction across end use sectors, helping to achieve CB6 and put the UK on a pathway to net zero. Government will continue to work closely with industry, regulators, consumers and the research and innovation community over the coming months and years to make sure that we do.

2.4 Use of hydrogen

Key commitments

- We will launch a call for evidence on **'hydrogen-ready' industrial equipment** by the end of 2021.
- We will launch a call for evidence on **phase out of carbon intensive hydrogen production in industry** within a year.
- We will deliver Phase 2 of the **£315m Industrial Energy Transformation Fund**.
- We will launch a **£55 million Industrial Fuel Switching 2 competition** in 2021.
- We will prepare for hydrogen for heat trials – a **hydrogen neighbourhood by 2023**, **hydrogen village by 2025** and **potential pilot hydrogen town by 2030**.
- We aim to consult in 2021 on **'hydrogen-ready' boilers** by 2026.
- We will continue our **multi-million pound support for transport decarbonisation**, including for deployment, trials and demonstration of hydrogen buses, HGVs, shipping, aviation and multi-modal transport hubs.

As set out in Chapter 1, low carbon hydrogen will have an important complementary and enabling role alongside clean electricity in decarbonising our energy system, with potential to help decarbonise heavy industry and provide greener, flexible energy across power, heat and transport. The roadmap in Chapter 2.1 shows how we expect use of hydrogen across the economy to develop over the course of the 2020s and beyond, with early demonstration in industry, heat and power and limited use in transport applications in the earlier part of the decade developing into a wide range of uses across multiple sectors by the late 2020s and into the mid-2030s under CB6.

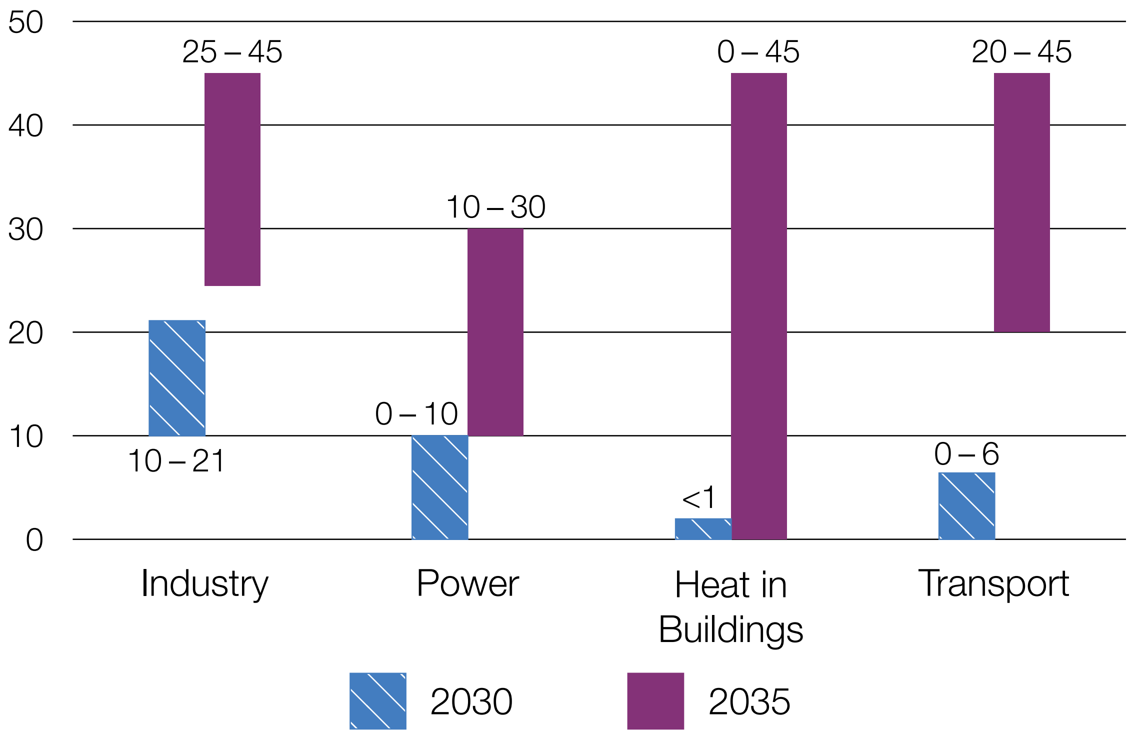
Unlocking the use of low carbon hydrogen can support efforts to deliver against many of the outcomes set out in Chapter 1.5, including decarbonising existing UK hydrogen production and use, establishing end-to-end systems with a diverse range of end users,

and supporting emissions reductions under CB4 and 5. The shift from fossil fuels to hydrogen can also be beneficial for the environment, including for air quality, although the extent of these benefits will depend on the mix of hydrogen technologies deployed. As such, deployment of hydrogen will need to consider these wider environmental costs and benefits.

In line with our strategic principles, we will support research, innovation and commercialisation of hydrogen technologies across a wide range of end uses, alongside testing and at-scale deployment, to help overcome the barriers facing low carbon hydrogen alternatives while allowing the market to determine the optimal technology mix. In doing so, we are aware that current early markets, for example road and depot-based transport, may differ from those where we expect hydrogen to play a more significant role in the longer term, such as in heavy industry. Our roadmap will help us design policy that encourages early use cases while bringing forward applications with the greatest strategic potential to support deep decarbonisation of the UK economy.

The state of current technology development, characteristics of hydrogen in relation to other low carbon energy sources and potential for cost reductions provide some indication of how the use of hydrogen in the UK is likely to develop in the near- to medium-term. Our analysis suggest potential hydrogen demand of up to 38TWh by 2030 split across sectors, not including use of hydrogen for blending into the gas grid. This could rise to 55-165TWh by 2035 under CB6 (see Figure 2.4 below).

Figure 2.4: Illustrative hydrogen demand in 2030 and 2035



Source: BEIS analysis (see analytical annex). Note: figures do not include blending into the gas grid.

We expect that industry will form a lead option for both early hydrogen use and in the longer term, with demand from hydrogen fuel switching picking up from the middle of this decade and hydrogen playing a key role in further decarbonisation of industry by the mid-2030s under CB6 and on the pathway to net zero.

Hydrogen is likely to play an important enabling role in a fully decarbonised power sector, through the system flexibility that electrolytic production and hydrogen storage can provide and the potential for flexible power generation using hydrogen as a fuel – helping to balance a more variable renewables-based electricity grid. We could see use of hydrogen in power in this way by the late 2020s with further scale up by the mid-2030s.

Hydrogen could also provide an important low carbon alternative – alongside electrification – to the UK's largely natural gas-based domestic heating sector, and government is supporting major studies and testing projects, including first-of-a-kind heating trials, to fill important evidence gaps on the costs, benefits and feasibility of using hydrogen for heating. This will be used to inform broader strategic decisions on heat decarbonisation in the middle of this decade. We are also exploring the option of blending hydrogen into the gas grid, with a decision to be taken in 2023 following testing of the safety, technical and economic case (see gas blending box in Chapter 2.5).

Finally, hydrogen is likely to be fundamental to achieving the full decarbonisation of transport, with particular potential in areas of heavy transport 'that batteries cannot reach'. Hydrogen buses are already in use in some UK towns and cities, and feasibility studies are underway for the use of hydrogen and other zero emission technologies in heavy goods vehicles (HGVs) with the aim of undertaking future years trials (subject to funding). We expect hydrogen to play a significant role in decarbonising international shipping and aviation, with demonstration and trials already underway, potential for early stage uses in shipping and aviation by the end of the decade, and an increasing role from the 2030s.

Given the wide range of applications and the strategic enabling role that hydrogen can play in an increasingly decarbonised economy, the 2020s will be critical to developing, testing and scaling up the use of low carbon hydrogen in the UK. The following sections set out how government and industry will work together to unlock the potential that hydrogen holds to decarbonise these important UK sectors.

2.4.1 Use of hydrogen in industry

It is clear that UK industrial sectors will play a vital role in developing a hydrogen economy over the next decade. Industry produced 16 per cent of UK emissions in 2018,[43] and hydrogen will be critical to decarbonise industrial processes that would be hard to abate with CCUS or electrification. The *Industrial Decarbonisation Strategy* published earlier this year sets out the policy and technology principles to decarbonise industry by 2050, including the installation of deep decarbonisation infrastructure such as hydrogen and CCUS networks in the 2020s.

Our industrial heartlands will likely lead the way for large scale low carbon hydrogen supply, and industrial users are expected to provide the most significant new demand for hydrogen by 2030 through industrial fuel switching. Today's hydrogen economy will need to scale up from its current base in the oil refining and chemical sectors, to enter other parts of industry and the wider energy system. We will develop policy to support and deliver this change, and to drive the decarbonisation of existing industrial hydrogen use.

Decarbonising current hydrogen production and use in industry

To meet our net zero ambition and develop the new low carbon hydrogen economy, we need to decarbonise existing industrial production of carbon intensive hydrogen. Today, hydrogen is mainly produced by steam methane reformation (without CCUS) for use as a feedstock, or as a by-product of other industrial processes. The most appropriate option to decarbonise existing production will vary for different types of industrial sites and will depend on factors such as the life cycle of current assets and the production method used. As the oil refining and chemical sectors are today often both producers and consumers of hydrogen, they could be important drivers of the transition to a low carbon hydrogen economy.

We will support hydrogen producers to decarbonise through, for example, the Industrial Carbon Capture and Hydrogen Business Models. Furthermore, we will finalise the design elements of a UK standard for low carbon hydrogen by early 2022.

We will also publish within a year a call for evidence to explore with industry the further interventions needed to phase out carbon intensive hydrogen and transition to low carbon production methods and sources, at the required pace to meet net zero.

Switching to low carbon hydrogen as an industrial fuel

Low carbon hydrogen can also provide an alternative to natural gas and other high carbon fuels currently used for industrial heating. This includes both indirect heating applications,

for example, using hydrogen to fuel steam boilers and combined heat and power (CHP) systems, and direct heating processes, such as melting glass in a furnace. Low carbon hydrogen is a good option for processes that are more expensive or harder to electrify, given its potential to replace natural gas.

The *Industrial Decarbonisation Strategy* set out that we expect, at a minimum, 20TWh per year of fossil fuel use to be replaced with low carbon alternatives, including hydrogen, electrification and biofuels, in 2030. Our latest analysis suggests that by 2030 demand from industry for low carbon hydrogen as a fuel could range from around 10TWh per year if supply is limited to clusters, up to around 20TWh per year if some dispersed sites are connected to pipelines.[44] Further demand could be realised from sites sourcing hydrogen from local electrolytic production. Fuel switching to low carbon hydrogen could yield carbon savings of around 3MtCO_2e per year by 2030, equivalent to taking 1.4 million cars off the road.

To meet CB6, we anticipate that industrial demand for low carbon hydrogen would need to continue to grow, reaching up to 45TWh by 2035. This increase would be driven by a growing number of sites with access to low carbon hydrogen, continued technology development to expand the range of processes capable of using hydrogen, and a shift in associated costs, such as the price of carbon, to make hydrogen an increasingly competitive fuel option. By 2050, in a scenario with widespread access to low carbon hydrogen across the UK, consumption in industry could be as high as 105TWh by 2050.

This strategy covers the full range of UK industrial sectors: metals and minerals, chemicals, food and drink, paper and pulp, ceramics, glass, oil refineries, and less energy-intensive manufacturing.[45] The greatest potential demand for low carbon hydrogen in 2030 arises from sectors such as chemicals and steel.

As set out in the *Industrial Decarbonisation Strategy*, decarbonising the steel sector will be essential to the decarbonisation of UK industry. The main options for doing so include using electric arc furnace technology coupled with hydrogen direct reduced iron, or CCUS. In collaboration with the Steel Council, we are considering the implications of the recommendation of the CCC to "set targets for ore-based steelmaking to reach near-zero emissions by 2035" and will provide an update in the forthcoming Net Zero Strategy.

Hydrogen could also be used to help abate the 6MtCO_2 emissions associated with the use of industrial non-road vehicles such as excavators and diggers used in a range of sectors. Machinery manufacturers are already developing equipment capable of using hydrogen, which alongside electrification may be an important way to decarbonise this sector. The adoption of hydrogen as a solution will depend on the development of wider hydrogen infrastructure.

We recognise that industry faces several barriers in fuel switching to low carbon hydrogen, even where it may offer the best decarbonisation option. These include the higher cost of low carbon hydrogen supply compared with fossil fuels; the capital cost of retrofitting or replacing equipment to be hydrogen-ready; the operational disruption of conversion and the subsequent costs associated with optimising new processes using hydrogen; and the operational risks associated with the security of supply of low carbon hydrogen, particularly in the short term while the market develops.

Demonstrating the technical performance of hydrogen, without compromising process efficiency or product quality, is also essential. As hydrogen has a distinct chemical composition and physical characteristics compared to current fuels, further research and testing will be needed in the 2020s. This will help industry to better understand how hydrogen transfers heat, how to limit any pollutants released during combustion (including NOx) and how this might impact materials and end products. In practice this will involve building on existing research with more lab-based studies, followed by at scale trials for distinct industrial processes.

What are we doing to deliver?

Given the scale of industrial emissions and the likely importance of hydrogen in replacing high-carbon fuels used in industry, it is critical that we demonstrate and scale up fuel switching to low carbon hydrogen on industrial sites during the 2020s. Government is already providing a range of funding opportunities that could support industry to switch to low carbon technologies including hydrogen, which complement the existing academic and private sector led initiatives in this area:

- The **£315 million Industrial Energy Transformation Fund** is supporting the uptake of technologies that improve efficiencies and reduce the carbon emissions associated with industrial processes. Hydrogen projects, subject to contract, were supported as part of Phase 1 of the competition.[46] The Fund aims to de-risk key technologies including hydrogen fuel switching by providing support for feasibility and engineering studies, and capital support for first movers to upgrade their industrial equipment. It will increase readiness for the hydrogen economy by building demand for hydrogen in industry and helping to develop the commercial case for low carbon hydrogen projects.

- The **£20 million Industrial Fuel Switching Competition** has allocated innovation funding to stimulate early investment in fuel switching processes and technologies. It has been highly successful in progressing the development of new fuel switching technologies across a range of sectors, including cement, refineries, glass and lime. The latest round of funding was awarded in winter 2019, with four projects moving from feasibility studies to demonstration, including the Mineral Products Association's world first demonstrations of firing hydrogen at commercial fuel supply scale for the manufacture of cement and lime.

- The **Green Distilleries Fund is providing £10 million of new innovation funding** to help distilleries go green. The programme is taking a portfolio approach and aims to fund a range of different solutions which could include electrification, hydrogen, biomass or waste. Nine of the 17 feasibility studies funded at Phase 1 are for projects using low carbon hydrogen.

Case study: Unilever demonstrates a hydrogen-fired industrial boiler

As part of the BEIS funded HyNet Industrial Fuel Switching competition, Unilever, working alongside Progressive Energy, is running a trial to switch an onsite natural gas fired boiler to hydrogen. The boiler, located at the Port Sunlight facility on the Wirral, raises steam needed for the manufacture of home and personal care products.

Switching to low carbon hydrogen allows the site to cut carbon emissions, with no change to manufacturing operations. This trial will provide Unilever with the evidence and confidence to convert existing boilers to run on low carbon hydrogen, once a supply is available. It seeks to demonstrate consistent steam production at the required temperature and pressure, reliable boiler operations, and adherence to NOx emissions limits.

Following successful trials on a representative boiler system at Dunphy Combustion's test site in 2021, a new 7MWth dual fuel (hydrogen and natural gas) burner will be installed in Unilever's boiler. The proportion of hydrogen fuel gas will be increased from 0 to 100 per cent over four days, with verification of steam quality and NOx emissions performance taking place, followed by several weeks of 100 per cent hydrogen firing for up to eight hours a day, providing steam for the Port Sunlight works.

Building on these successes, later this year we will launch a number of further funds to support industry to switch to hydrogen and other low carbon fuels:

- **We will provide further grant funding to support fuel switching technologies, including low carbon hydrogen, through Phase 2 of the £315m Industrial Energy Transformation Fund.**
- **We will launch a new £55m Industrial Fuel Switching 2 Competition to develop and demonstrate innovative solutions for industry to switch to low carbon fuels such as hydrogen.**
- **We will launch a new £40 million Red Diesel Replacement Competition to fund the development and demonstration of innovative technologies that enable Non-Road Mobile Machinery (NRMM) used for quarrying, mining, and construction to switch from red diesel to hydrogen or other low carbon fuels.**

Throughout the early 2020s, we will also be supporting the engineering and technical design elements of decarbonisation projects across the UK's industrial clusters through UKRI's **Industrial Decarbonisation Challenge**, to accelerate the deployment of technologies such as CCS and hydrogen fuel switching.

Building on this substantial existing industrial decarbonisation support, we will need additional dedicated support for fuel switching to hydrogen, including for further research and innovation, and demonstration and deployment of early use cases in the 2020s. To accelerate fuel switching to low carbon hydrogen, **we will seek to support research and innovation through the existing Net Zero Innovation Portfolio and initiatives led by the Industrial Decarbonisation Research & Innovation Centre (IDRIC). We will also**

engage with industry later this year on possible requirements for a research and innovation facility to support hydrogen use in industry and power.

Due to infrastructure requirements, demand will likely be concentrated in large industrial clusters during the 2020s, a significant proportion of which could arise from a small number of sites. These sites could act as 'pathfinders', proving the viability of hydrogen as a fuel at commercial scale, and helping to foster an initial market for low carbon hydrogen close to supply. **We will work with cluster projects to better understand the opportunities that pathfinder sites present, so to maximise the benefit to the sites themselves and the associated clusters.**

Initially, hydrogen will likely be used to fuel indirect heating technologies such as steam boilers and CHP units. Given the range of sectors that use steam as part of an industrial process, our analysis indicates that boilers and CHPs could make up around two thirds of demand for hydrogen fuel switching by 2030. We will therefore focus on policies to unlock the fuel switch potential for these technologies, taking into account replacement cycles of existing equipment. Work is ongoing to establish the role of hydrogen in decarbonising CHPs, and **by the end of this year we will launch a new call for evidence on 'hydrogen-ready' industrial equipment.**

Later in the decade, hydrogen could replace methane in different parts of the gas grid, either partially through blending or fully with 100 per cent hydrogen (see Chapter 2.5 for further detail on blending). Among the current users of the gas network, industry has the most variation in terms of types of equipment and uses of natural gas. Government is working with industry and with regulators to identify the changes that would be necessary to transition to full or blended hydrogen in the gas grid, and how this could impact industrial settings. **We will work with industrial end users to ensure their needs and the potential impacts of a full or partial transition to hydrogen via the gas grid are well understood.**

Collectively, this extensive set of measures will help UK industrial sectors better understand the challenges and opportunities of switching to low carbon hydrogen. Unlocking demand for low carbon hydrogen in industry will deliver significant carbon savings and help scale up the hydrogen economy. Demand from industry can act as an anchor to stimulate production, which will in turn help decarbonise other end use sectors in both industrial clusters and dispersed sites across the UK.

2.4.2 Use of hydrogen in power

As set out in the *Energy White Paper*, government is aiming for a fully decarbonised, reliable and low-cost power system by 2050, which will require the rapid growth in renewables which has been a key driver of emissions reductions to date. To meet CB6 on the way to this, we must aim for a largely decarbonised power sector by the mid-2030s. Deployment of renewables and other forms of low carbon generation is projected to further scale up, demand for electricity will increase as more sectors shift to electrification, and power generation will become more decentralised, variable and intermittent as we become increasingly dependent on wind and solar. To support this transition, we will need more flexible, low carbon generation and flexible technologies such as energy storage and demand-side response to manage demand peaks and to balance electricity supply and demand.

Low carbon hydrogen can play an important strategic role in meeting these future power system needs, and developing and scaling hydrogen in power during the 2020s can reduce the burden on other technologies such as renewables, CCUS and nuclear. While not a 'silver bullet', there are two key roles that hydrogen could play in the power system:

- **Flexible power generation** ('Gas to Power'): Low carbon hydrogen can play an important role in providing flexible power generation such as such as through rapid operating 'peaker' plants and larger scale but less flexible Combined Cycle Gas Turbines (CCGTs), helping to meet short- and longer-term peaks in demand. This hydrogen could be used either as a blend or at 100 per cent and would be supplied by pipeline or through access to storage. Our analysis[47] indicates that by 2030, we could see a small but important role for low carbon hydrogen to generate power, with demand for hydrogen in power ranging from 0-10TWh. We expect to see further ramp up beyond 2030: hydrogen demand could increase to 10-30TWh in 2035, and 25-40TWh by 2050. Using hydrogen in this way could also play a role in establishing secure offtake for hydrogen production projects in the near term.

- **System flexibility through electrolysis and storage** ('Power to Gas', 'Power to Gas to Power'): Electrolytic hydrogen production can also provide grid flexibility by drawing on 'excess' renewable or low carbon electricity that would otherwise be constrained or curtailed (where power cannot be transmitted) and where there is an economic case to do so. In this way electrolytic hydrogen can allow excess electricity to flow across different parts of the system, from power to gas, to transport or industry (often referred to as 'sector coupling'). This unlocks a wide range of system benefits and can provide an additional route to market for new and existing renewables capacity. Coupling this electrolytic production with storage, including long duration storage where hydrogen is a lead option (see Chapter 2.3.2), can help integrate hydrogen further into our power system by helping to balance the grid when generation from renewables is higher or lower than demand.

How will we develop and scale up hydrogen in power over the 2020s?

Use of hydrogen in power will need to rapidly scale up through learning by doing in the 2020s to support further decarbonisation by the 2030s and to realise this strategic role in a fully decarbonised power sector in the long term.

From the mid-2020s, as demand for flexible power generation increases, we expect hydrogen blends to be the primary use of hydrogen in the power sector, shifting to the first 100 per cent hydrogen turbines later in the decade. At smaller scales, we could see hydrogen fuel cells playing a role, replacing high carbon alternatives such as diesel generators to provide flexibility and backup generation for off grid locations and in cities, building on limited deployment to date. From 2030, we expect that low carbon hydrogen, and potentially ammonia (subject to meeting air quality and emissions standards), will play an increasing role in providing peaking capacity and ensuring security of supply.

As the need for flexibility and renewables deployment increases out to 2030, we expect to see increasing deployment of electrolyser capacity, both contributing to delivering our 5GW ambition and supporting decarbonisation of power and other sectors where there is an economic case to do so. The 2020s will be focused on deploying a future generation of electrolysers which will be larger and better adept at operating variably in line with renewables. Throughout the 2020s and out to 2030 we anticipate long duration hydrogen storage coming online and scaling up, integrating hydrogen into our power system and coupled with flexible generation where this is needed.

To achieve this integration of hydrogen in the power sector by 2030, we will need to tackle the key barriers to deployment in the early part of this decade:

- *Technology and user readiness:* We need to demonstrate a range of technologies across the hydrogen value chain, including next-generation electrolysers, large scale hydrogen storage, and 100 per cent hydrogen turbines, which are not yet commercially available in the UK. We also need to ensure hydrogen or ammonia firing is aligned to wider emissions standards. Secure availability of hydrogen will be critical to addressing this barrier.

- *Designing supporting policy and market frameworks:* We need to better understand the role of hydrogen across the power system, and drive investment in hydrogen power applications alongside hydrogen production, primarily through existing or planned policy frameworks to help unlock demand in the power sector.

- *Availability of networks and storage:* The location of hydrogen power generation and system flexibility in the 2020s and out to 2035 will in part be driven by the availability of hydrogen network and storage infrastructure, including non-pipeline distribution for smaller scale applications.

What are we doing to deliver?

There are currently few examples of low carbon hydrogen use in the power sector, despite hydrogen technologies being eligible to participate in electricity markets including the Capacity Market and balancing services, some fuel cells and turbines already being capable of accepting hydrogen, and testing underway to commercialise 100 per cent hydrogen turbines at larger scales. The Industrial Decarbonisation Challenge is also supporting the development of hydrogen power generation as part of wider cluster proposals.

In light of this, government has recently undertaken a series of actions to better understand the role of, and the support needed for, hydrogen in power, including:

- Publishing our **Modelling 2050 - Electricity System Analysis report**[48] alongside the Energy White Paper in December 2020 which focused on building our evidence base to better understand the implications of net zero on our power system, and included exploring the potential role of hydrogen in our changing energy system.

- Publishing a **Call for Evidence on enabling a high renewable, net zero electricity system** in December 2020,[49] which explored options to evolve the current Contracts for Difference (CfD) mechanism for future allocation rounds, including coupling of technologies that can deliver increased flexibility, such as electrolysis.

- Publishing a **Call for Evidence on 'Decarbonisation Readiness' for new power generation** in July 2021,[50] which sought views on removing the 300MW threshold and expanded the technology types covered to the majority of combustion equipment. The proposals include hydrogen conversion as an alternative decarbonisation route alongside CCUS. New build plants would need to be capable of accepting either hydrogen blends of 20 per cent or be 'CCUS ready' from initial operation. From 2030, plants would be expected to be capable of accepting 100 per cent hydrogen.

- Publishing a **Call for Evidence on facilitating the deployment of large-scale and long-duration electricity storage**, in July 2021,[51] which sought views on barriers that electricity storage technologies face, including information regarding hydrogen technologies that are used in the power system.

- Publishing **Capacity Market 2021: a Call for Evidence on early action to align with net zero** in July 2021,[52] particularly focusing on actions to bring forward more low carbon capacity in the future such as hydrogen-fired generation.

In addition to this evidence gathering activity, we recognise the need to take further concrete and coordinated action now to develop and scale up hydrogen use in the power sector. Building on recent announcements, **we will engage with industry to understand the economics and system impacts of introducing hydrogen into the power sector, including sector coupling and hydrogen energy storage.** Further updates will be published in due course, including the response to our recently published Decarbonisation Readiness Call for Evidence.

We will review the progress of our recent actions, and engage with relevant stakeholders and hydrogen projects early to ensure there is suitable support for hydrogen in the power sector to deliver against our vision for 2030.

We will also take steps to demonstrate the technologies needed for hydrogen use in power. As detailed in the Chapter 2.3, **subject to competition we are supporting innovation in energy storage through electrolysis via our £68 million Long Duration Storage Competition.** As set out in Chapter 2.4.1 above, **we will also engage with**

industry on possible requirements for a research and innovation facility to support hydrogen use in industry and power.

By building our evidence base, and taking early action to support research and innovation, demonstration and deployment of low carbon hydrogen technologies in power, we can support further decarbonisation of the power sector by 2030 and for CB6 and help to establish a reliable, long term source of low carbon hydrogen demand.

2.4.3 Use of hydrogen in heat in buildings

Heating comprises 74 per cent of buildings emissions in the UK and about 23 per cent of all UK emissions.[53] While the electricity that powers our lighting and appliances is decarbonising fast, the majority of buildings still rely on fossil fuels – largely natural gas – for space heating, hot water and cooking. Meeting our net zero target by 2050 will therefore require us to switch to low carbon alternatives to heat the 30 million residential, commercial, industrial and public sector buildings in the UK.[54]

Given the scale of this challenge, it is essential that we start the transition now to meet our emissions reductions targets cost-effectively, minimise disruption, and ensure that households continue to enjoy a reliable and comfortable heating system. Over the 2020s and early 2030s, our aim is to move to only installing low carbon heat systems that are compatible with our net zero target, and we will keep pace with the natural replacement cycles of heating systems throughout the rest of the 2030s and into the 2040s. Our forthcoming *Heat and Buildings Strategy* will set out how we plan to decarbonise heat in buildings in the UK.

How will we develop the potential use of hydrogen for heat over the 2020s?

While we are clear on the need to decarbonise heating to meet net zero, there is still a degree of uncertainty over the best route to decarbonising heat at scale in the UK. Low carbon hydrogen could be one of a few key options for decarbonising heat in buildings, alongside more established technologies such as electricity and heat networks. While there is more work to do to test the feasibility of using hydrogen, it could become a like-for-like alternative for buildings currently heated by natural gas from the grid.

We will need to be flexible in how we decarbonise heat in buildings given the diversity of heat demand across different building types and geographies in the UK. We are taking action to build heat pump and heat networks markets, especially in areas where we do not expect hydrogen to play a major role. Delaying action could prevent us from meeting near-term carbon budget and fuel poverty targets, making it harder to achieve our targets in later years.

Before hydrogen for heating can be considered as a potential option to decarbonise heat in buildings, we need to generate further evidence on the costs, benefits, safety, feasibility, air quality impacts and consumer experience of using low carbon hydrogen for heating relative to other more established heat decarbonisation technologies. The 2020s will be critical for understanding hydrogen's potential role, and government is working with industry, network operators and local partners on major studies and testing projects to help establish the evidence required.

Although we expect overall the demand for low carbon hydrogen for heating by 2030 to be relatively low (<1TWh), if the feasibility and positive case for hydrogen heating is established, heat in buildings could become a very significant source of future demand for hydrogen with implications for the design and timing of hydrogen production, storage and network infrastructure: our analysis suggests hydrogen demand for heat in buildings could be up to 45TWh by 2035.[55]

What are we doing to deliver?

A wide range of relevant work is already underway. For example, ongoing industry-led projects are exploring the distribution and transmission of hydrogen within gas networks, such as the HyNet project in the North West of England and H21 project on distribution across the North of England, and HyNTS and LTS Futures projects on transmission led by National Grid (see Chapter 2.3.1 for more detail). Additionally, the BEIS-funded £25m Hy4Heat programme, which is due to end this year, has supported the development and demonstration of '100 per cent hydrogen-ready' appliances and components. The Hy4Heat programme has also developed a framework for skills accreditation for heating engineers working with hydrogen.

As set out in the *Ten Point Plan*, **we are supporting industry to conduct first-of-a-kind hydrogen heating trials, including a neighbourhood trial by 2023 and a village scale trial by 2025.** The village trial will look to build on learning from the neighbourhood trial, involving a larger and more diverse range of consumers, and conversion of existing local area gas infrastructure to 100 per cent hydrogen.

The trials will provide evidence on the practical, logistical and technical issues involved in converting buildings and appliances. In particular, they will test and demonstrate how consumers experience the installation and use of hydrogen for heating in their homes and workplaces; the conversion, operation and performance of gas networks using hydrogen; and the skills and training required to deliver a conversion.

By 2025 we will also develop plans for a possible hydrogen heated town before the end of the decade. This planning work will also contribute important evidence on the feasibility and costs of converting from natural gas to hydrogen heating. We anticipate that if the case is made for wide scale conversion of the gas grid to full hydrogen, it would begin with converting a pilot town in the late 2020s and accelerate from the early 2030s, taking into account the practical implementation experience gained through the pilot.

The local trials and planning work, together with the results of our wider research and development and testing programme, will enable strategic decisions by 2026 on the role of hydrogen for heat and whether to proceed with the hydrogen town.

Case Study: hydrogen for heat in homes

H100 Fife Neighbourhood Trial: This Levenmouth, Fife-based project will deliver the world's first hydrogen-to-homes gas network in 2023. The trial will provide hydrogen to 300 homes for heating and cooking on an opt-in basis, switching from natural gas. The hydrogen used in these trials will be produced locally from offshore wind power. This ground-breaking project led by gas network SGN is collaboratively funded by SGN and its GDN partners Cadent, NGN and WWU, Ofgem and the Scottish Government. The H100 project will also provide evidence to assess consumers' experience of using hydrogen in the home and provide key learning on gas networks, such as constructing and operating a hydrogen network, that can be applied to future grid conversion projects.

We will continue to support research and innovation on hydrogen heating. Our new Net Zero Innovation Portfolio will allow further support to be directed towards innovation for end-users of hydrogen heating as needed, following on from Hy4Heat endpoints.

We are also accelerating work to consider how a market for hydrogen heating could operate, recognising the need to start adapting legislative and regulatory frameworks in advance of any strategic decisions being made on the role of hydrogen in heat. We are working with key regulators, including HSE and Ofgem, to ensure that we understand the regulatory changes, including timelines, that may be needed to roll out any future scenario for hydrogen heating.

Alongside wider market policy, we are actively considering the value of specific interventions to support the commercialisation of hydrogen heating products. **We aim to consult later this year on the case for enabling, or requiring, new natural gas boilers to be easily convertible to use hydrogen ('hydrogen-ready') by 2026.** We will also use this consultation to test proposals on the future of broader boiler and heating system efficiency and explore the best ways to reduce carbon emissions from our gas heating systems over the next decade.

Hydrogen has the potential to play a key role in decarbonising heat in buildings in the UK. We are rapidly delivering major studies and testing work to understand the feasibility of using hydrogen for heating, to inform broader strategic decisions in 2026 on heat decarbonisation.

2.4.4 Use of hydrogen in transport

Hydrogen is likely to be fundamental to achieving net zero in transport, potentially complementing electrification across modes of transport such as buses, trains and heavy goods vehicles (HGVs). It is also likely to provide solutions for sectors that will not be able to fully decarbonise otherwise, including aviation and shipping.

Low carbon hydrogen can provide an alternative to petrol, diesel and kerosene as it can be used directly in combustion engines, fuel cells and turbines or as feedstock for production of transport fuels, including ammonia and sustainable aviation fuels. We expect low carbon hydrogen to play a key role in decarbonising the sector, which is the largest single contributor to UK domestic GHG emissions and was responsible for 27 per cent of emissions in 2019.[56]

Transport is also a crucial early market for hydrogen, driving some of the earliest low carbon production in the UK. There are over 300 hydrogen vehicles on UK roads, mostly passenger cars and buses, and the government is supporting hydrogen use in transport with a **£23 million Hydrogen for Transport Programme**.[57]

Our latest analysis places transport as one of the biggest components of the hydrogen economy in future, with 2050 demand potentially reaching up to 140TWh.[58]

How will we develop and scale up hydrogen in transport over the 2020s?

We expect that the role of hydrogen in transport will evolve over the course of the 2020s and beyond. To date, road transport has been a leading early market for hydrogen in the UK. Going forward, we expect hydrogen vehicles, particularly depot-based transport including buses, to constitute the bulk of 2020s hydrogen demand from the mobility sector. Fuel cell hydrogen buses have a range similar to their diesel counterparts. Back-to-depot operating means hydrogen refuelling infrastructure can be more centralised and is likely to be compatible with distributed hydrogen production expected in this period. Concurrently, we will undertake a range of research and innovation activity which will focus on difficult to decarbonise transport modes, such as heavy road freight. As we demonstrate and understand these larger-scale applications we are likely to see more diversity in transport end uses in the late 2020s and early 2030s.

By 2030, we envisage hydrogen to be in use across a range of transport modes, including HGVs, buses and rail, along with early stage uses in commercial shipping and aviation. Our analysis shows there could be up to 6TWh demand for low carbon hydrogen from transport in 2030. Beyond this we expect to see an increased role for hydrogen in aviation and shipping decarbonisation which could become a large component of the overall hydrogen demand in the long term.[59] To meet CB6 in 2035 we estimate the demand from transport could be 20-45TWh.[60]

We recognise that the longer-term role for hydrogen in transport decarbonisation is not yet clear, but it is likely to be most effective in the areas where energy density requirements or duty cycles and refuelling times make it the most suitable low carbon energy source. Key challenges in this area include technology uncertainty, lack of existing hydrogen infrastructure, cost differentials and low numbers of hydrogen powered vehicles. Continued investment in research and innovation by government and industry will help to overcome these. As we learn more about ways in which hydrogen can be used in transport, we will need to put policy in place to support this technology rollout.

What are we doing to deliver?

Throughout the 2020s, government is taking forward a programme of development and demonstration of hydrogen technologies across different transport modes, to support commercial readiness and create real-world learning about the opportunities and barriers for any larger scale rollout.

Public transport

Approximately two per cent of England's local operator bus fleet is now zero emission – battery electric or hydrogen fuel cell.[61] **We will deliver the National Bus Strategy and its vision of a green bus revolution, including setting an end date for the sale of new diesel buses and the Zero Emission Bus Regional Areas (ZEBRA) scheme. ZEBRA will provide up to £120 million in 2021/22 to begin delivery of 4,000 new zero emission buses, either hydrogen or battery electric, and the infrastructure needed to support them.**

Rail is already one of the greenest ways of moving people and goods, and government is committed to making it even greener, in line with our net zero target by 2050. To decarbonise currently unelectrified parts of the network, electrification will likely be the best solution because electrified trains are faster, quicker to accelerate, more reliable and cheaper. There will also be a role for new traction technologies, like battery and hydrogen trains, on some lines where they make economic and operational sense.

Heavy Goods Vehicles

Large long-haul HGVs are the most challenging segment of the road sector for developing zero emission options due to their long journey distances and heavy payload requirements. Some vehicles are in constant use and therefore require fast refuelling to meet operational requirements. **We are investing up to £20 million this financial year in designing trials for electric road system and hydrogen fuel cell HGVs and to run a battery electric trial to establish the feasibility, deliverability, costs and benefits of these technologies in the UK.** To further support the shift away from fossil fuels, government is also consulting on the phase out date for the sale of new non-zero emission HGVs.

Shipping and aviation

Shipping and aviation are responsible for approximately five per cent of global emissions[62] and are some of the most difficult areas of transport to decarbonise.

Hydrogen in shipping

Low carbon hydrogen and hydrogen-derived fuels like ammonia and methanol are likely to play a crucial role in the decarbonisation of the maritime sector. Analysis commissioned by the Department for Transport (DfT) estimated that by 2050 there could be 75-95TWh of demand for hydrogen-based fuels (principally in the form of ammonia) from UK domestic and international shipping.[63] Coupled with decarbonisation of road and rail freight, hydrogen use in shipping could help create an end-to-end low carbon freight system from port to door.

The potential for adopting battery electric technology in the maritime sector is mostly constrained to domestic navigation: the size and weight required for battery powered ships means that their range is limited and they are not a compatible option with larger ship types.[64] Hydrogen could be used to decarbonise ships directly, through combustion or in fuel cells, or as feedstock for methanol or ammonia. Liquid ammonia is more energy dense than hydrogen meaning less storage volume is required on vessels, which may represent an effective option for larger ships on long-distance routes. Ammonia is also already internationally transported on ships so some infrastructure and supporting regulations are in place (although this ammonia is currently not low carbon).

Additionally, as set out in DfT's *Clean Maritime Plan*, research has estimated that the global market for the elements of alternative fuel production technologies in which the UK has a particular competitive advantage (for example, upfront design) could rise to around $11–15 billion per year (£8–£11 billion per year) by the middle of the century. If the UK were able to maintain its current export market share (estimated to be around 5 per cent of relevant global markets), this could result in economic benefits to the UK of around $490–690 (£360–£510) million per year by the middle of the century. This research also found that while there are significant opportunities for the UK across all abatement options considered, the UK has the strongest competitive advantage in hydrogen and ammonia production technologies, alongside onboard batteries and electric engines.[65] **Government launched the £20 million Clean Maritime Demonstration Competition in March this year, which aims to accelerate the design and development of zero emission vessels in the UK and will lay the foundations for a network of technology demonstrations, fast-tracking maritime decarbonisation.**[66]

Government is also exploring the establishment of a UK Shipping Office for Reducing Emissions (UK-SHORE). This is a dedicated unit within the Department for Transport focused on decarbonising the maritime sector. UKSHORE will build on the success of the Clean Maritime Demonstration Competition, delivering a suite of interventions inspired by our experience with decarbonising other transport modes, looking at programmes such as the Office for Zero Emission Vehicles and the Future Fuels for Flight and Freight Competition.

UK-SHORE aims to transform the UK into a global leader in the design and manufacturing of clean maritime technologies and fuels such as hydrogen and ammonia. Government will continue to engage with industry to consider how the establishment of this programme in cooperation with UKRI and Innovate UK could unlock the necessary industry investment in clean maritime technologies, tackling supply- and demand-side barriers as well as developing infrastructure and consumer confidence.

Case Study: hydrogen in shipping

HySeas III is the final development stage of a programme to deliver a procurement-ready design for what the team hopes will be the world's first sea-going vehicle and passenger ferry to employ carbon-free hydrogen as its energy source. The vessel is planned to operate in and around Orkney and will use hydrogen which is currently being produced on the islands from renewable energy. The HySeas project is supported by approximately £10.8 million in funding, of which £8 million is provided by the European Union Horizon 2020 programme.

Hydrogen in aviation

The proportion of UK GHG emissions from aviation is expected to increase in the future as other sectors decarbonise. We need to tackle these emissions and are keen to do so in a way that capitalises on UK strengths in the aerospace and aviation sectors. To realise this, government has established the Jet Zero Council, a partnership between industry and government, to focus efforts on accelerating decarbonisation, including with an aim to deliver zero emission transatlantic flight within a generation. More recently, in July 2021 we published our 'Jet Zero Consultation' which seeks view on our proposed approach to reaching net zero aviation.

While there are technological challenges to overcome before hydrogen is used in aviation, interest from the aviation industry is significant. Airbus have announced their ambition to develop and launch a zero-emission large commercial aircraft, powered by hydrogen propulsion, by 2035.[67] Alongside this, through the *Aerospace Technology Institute (ATI) programme*, government is supporting a number of projects in this area.

Case Study: Aerospace Technology Institute funded aviation innovation

HyFlyer I and II (£15m): This landmark project provided ZeroAvia with funding to retrofit a small (six seat) aircraft with a hydrogen fuel cell powertrain, which completed the first-ever hydrogen powered flight of commercial-grade aircraft in September 2020. The flight also showcased a full zero-carbon emission ecosystem, with onsite hydrogen production via electrolysis. The funding is also supporting the company to scale up their technology for use in a 19-seat aircraft. ZeroAvia plan to have a commercial product by 2024.

FlyZero (£15m): An in-depth study to help UK aerospace develop a zero-carbon emission aircraft by 2030. The ATI-led project will bring together expertise from across the UK supply chain and universities to explore the design challenges and market opportunity of potential zero-carbon emission aircraft concepts and will be key in answering questions on the role and importance of hydrogen in decarbonising aviation.

H2GEAR (£27m): This ongoing project aims to develop a liquid hydrogen propulsion system – where liquid hydrogen is converted within a fuel cell system - for a sub-regional aircraft that could be scaled up to larger aircrafts. The programme is led by GKN Aerospace, alongside a number of industry and academia partners, from their Global Technology Centre in Bristol. GKN Aerospace believes the entry into service of hydrogen powered aircraft could be as early as 2026.

Additionally, hydrogen can be used to refine and produce Sustainable Aviation Fuels (SAF).[68] SAF could play a key role in emissions reduction in the short and medium term and the development of a SAF industry in the UK could see thousands of new jobs across the country.[69] **In March this year, we launched the £15 million 'Green Fuels, Green Skies' competition to support the production of first-of-a-kind SAF plants in the UK.** Government has set out its proposed ambition for SAF uptake in its SAF blending mandate consultation, which was recently published.[70]

A multi-modal place-based approach

Areas with particularly strong hydrogen potential could help to improve our understanding of the role of hydrogen in transport, drive local industrial strategies and jump start green recovery. **The UK's first 'Hydrogen Transport Hub' in Tees Valley will bring together government, industry and academia to focus on future hydrogen research and development, real world testing and demonstrations.** The Hub, supported by £3 million of initial government development funding this year, will bring a number of hydrogen vehicles to public roads and waterways, alongside the associated refuelling infrastructure. **In March this year we also announced that we will provide £4.8 million (subject to business case) to support the development of a hydrogen hub in Holyhead, Wales.** This will pilot the creation of hydrogen from renewable energy and its use as a zero-emission fuel in HGVs.

Case Study: a 'living lab' for hydrogen powered transport

Tees Valley Hydrogen Transport Hub: The hub will act as a living lab to understand hydrogen's role in decarbonising the transport sector, through large scale trials across different transport modes and use cases. The first of its kind in the UK, this project will comprise of a set of facilities for the production, storage and distribution of green hydrogen to supply a network of refuelling stations and support operational trials of hydrogen powered vehicles including road, waterways and aviation. The hub brings together government, industry and academia, and is expected to be fully operational by 2025 (subject to funding). This year the Tees Valley area will see various pilot projects of hydrogen vehicle demonstrations across modes and use cases including, but not limited to, forklifts, cars, buses, HGVs and marine vessels.

Supporting policy: the Renewable Transport Fuel Obligation

The Renewable Transport Fuel Obligation (RTFO) aims to increase the use of renewable transport fuels. Hydrogen produced by electrolysis using renewable electricity, as well as biohydrogen, for example produced through methane reformation of biomethane, are supported through the scheme. In March 2021, government published a consultation on the amendments to the scheme which sought views on a number of issues related to hydrogen support, including expanding the scope of the RTFO to make renewable fuels from non-biological origin used in maritime, rail and non-road vehicles eligible for support. Government's response to the consultation was recently published, with changes intended to come into effect from January 2022.

Hydrogen is a key alternative to the use of fossil fuels in transport – as well as in industry, power and heat – and will be essential to meeting our CB6 and net zero targets. We will continue to build on our strengths in research and innovation and expertise along the hydrogen value chain to fully realise the potential of hydrogen to support decarbonisation across end use sectors over the coming decade and beyond.

2.5 Creating a market

Key commitments

- We will set out further detail on the **revenue mechanism** which will provide funding for the Business Model in 2021.
- We will establish a **Hydrogen Regulators Forum** in 2021.
- We will assess **market frameworks** to drive investment and deployment of hydrogen, and provide an update in early 2022.
- We will assess **regulatory barriers** facing hydrogen projects, and provide an update in early 2022.
- We will complete an indicative assessment of the value for money case for **blending up to 20 per cent hydrogen into the existing gas network** by late 2022, and aim to make a final policy decision in late 2023.

The development and scaling up of each part of the hydrogen value chain will rest on policy frameworks to support the early expansion of a low carbon hydrogen market over the 2020s, and its later evolution to a dynamic, competitive, integrated and liquid market from the 2030s onwards.

Energy markets have evolved significantly over time, from the move to privatisation in the 1980s, to the transformation brought about by the Electricity Market Reform (EMR) programme set out in the Energy Act 2013, which set the path for rapid UK power sector decarbonisation. We have also seen the market respond to the decline in domestic gas production from the North Sea by building new natural gas terminals and pipelines to improve diversity of supply.

EMR and the changes in supply of gas happened against the backdrop of an already functioning market, albeit one that faced significant challenges to enable the long term decarbonisation ambitions set out in the Climate Change Act 2008.[71] Now, with more stringent CB6 and net zero targets, we need to reach for a new set of technologies like CCUS and low carbon hydrogen, which must be supported by complex new infrastructure systems. These newcomers to the UK energy landscape, as enablers for a deeply decarbonised and deeply renewable system, require a whole-system approach to development, with new support models to stimulate nascent markets.

There is much we can learn from the evolution of the gas and electricity markets, particularly from EMR. However, the hydrogen market is both complex and in its infancy. Reform of energy markets takes time, as will the growth of the hydrogen market. It would be near impossible to design a fully functioning hydrogen market for 2050 today – not

least because there remains significant uncertainty about its precise role and scale on this timeframe.

As the CCC's and our own analysis makes clear, rapid progress and learning by doing in the 2020s is vital. The roadmap at Chapter 2.1 highlights a challenging trajectory to meet our 2030 ambition and CB6 beyond this. While government intervention across the hydrogen value chain will be essential, we remain committed to market-led approaches that build and maintain competitive tension. Given the nascent state of the hydrogen market, it will be important that we learn and evolve, just as we have in the renewables market. In this, we will work closely with private sector partners to develop policy and signal next steps to attract the investment required. While this strategy package sets out the initial steps, there is far more to do, and we will continue to develop policy over coming months and years.

As set out in Chapter 1.5, a key strategic principle for government will be to take a 'holistic approach' to delivering our 2030 ambition and creating a thriving market for low carbon hydrogen. This means that any decision or action taken across the hydrogen value chain will inform and be informed by broader objectives and plans for the UK energy system, environment, economy and society including those set out in the forthcoming Net Zero Strategy. We will consider the implications of decisions and changes in the wider energy system, including dependencies on the deployment of energy infrastructure such as CCUS or offshore wind, as well as the impact of low carbon hydrogen on the wider system, for example in the potential for hydrogen to support integration of renewables with added benefits for energy security and resilience. This systemic approach to policy development is critical for success, both for developing a thriving hydrogen economy and to deliver our broader net zero objectives.

Our approach will therefore not be limited to the commercialisation and application of new hydrogen technologies. Government action will be required to put in place a wider policy framework covering regulations and, where needed, market support mechanisms in production, demand and supporting network and storage infrastructure, taking account of evolution in the electricity and gas markets and linkages to wider economic activity and networks. It will also be essential to raise consumer awareness, seek buy-in and to work through key issues such as policy governance and fair distribution of the costs and benefits of low carbon hydrogen.

Features of the emerging hydrogen market

The hydrogen market is currently limited to specific industrial settings, with high carbon production and use typically co-located. At much lower volumes, small scale electrolytic hydrogen is also starting to be used in the transport sector. Low carbon hydrogen value chains will differ according to location and circumstances, and be driven by production method, network infrastructure availability and demand profile. Creating a hydrogen market fit to serve a deeply decarbonised energy system will require concerted action to bring forward the necessary private investment across the value chain and enable the balance of supply and demand in a nascent market.

As set out in the roadmap at Chapter 2.1, the hydrogen market can be expected to grow and change significantly over the 2020s and out to the mid-2030s. For this evolution to happen, we will need to overcome a number of barriers across the value chain, especially in the early phases of market development. Consistent with challenges set out in previous sections of this strategy and in detail in the analytical annex, these barriers include:

- *High production and user costs*, relative to high-carbon counterfactuals.
- *Demand uncertainty*, overall and arising from specific end-use sectors – with BEIS analysis for CB6 suggesting 250-460TWh of hydrogen could be needed in 2050.
- *Policy and regulatory uncertainty*, which in this nascent market may deter investments across the value chain, especially as the regulatory framework is complex, including regulations relating to the environment, safety, markets, competition, planning, and specific end uses.
- *First mover disadvantage*, with early adopters taking significant initial risks but ‘sharing’ benefits with later entrants.
- *Technology uncertainty*, with most hydrogen technologies yet to be commercially demonstrated at scale.
- *Investor uncertainty*, both on the production and demand side, as well as for supporting network and storage infrastructure.
- *Lack of hydrogen* distribution and storage (covered in more detail in Chapter 2.3).

To overcome these challenges, government intervention will be required, both specifically to bring forward investment in new hydrogen production capacity in line with our 2030 5GW ambition, and more widely across the value chain through targeted support and regulation. Such policies will seek to enable the low carbon hydrogen market to grow from fragmented initial stages to a highly integrated, competitive, transparent and liquid end state where hydrogen can compete against other technologies without support.

Different types of government intervention are likely to be required as the hydrogen market matures and expands, for instance to facilitate new end uses, noting that early uses may differ from those that will be most significant in the long term. The market failures and barriers faced by first-of-a-kind hydrogen projects operating in small, highly localised markets are unlikely to be the same as those faced by nth-of-a-kind projects operating in larger regional, national or even international markets. Greater price discovery and convergence, alongside cost reductions and learning by doing, will also affect the nature and structure of the market and policies that frame and support it. In time, the low carbon hydrogen market has the potential to become substantial, highly liquid and subsidy-free.

2.5.1 Developing the market framework for hydrogen

The market framework for low carbon hydrogen can be understood as the policies and interventions that directly or indirectly support or impede the supply and use of low carbon hydrogen, including the regulations that guide what markets it can be sold into, for instance in industry, power, heat or transport. This strategy and accompanying consultations, most notably on the Hydrogen Business Model, provide the first steps in developing the market framework for hydrogen. These are the steps we consider to be most important to kick-start the UK hydrogen economy, having worked closely with a wide range of stakeholders in recent years.

What are we doing to deliver?

In developing the market framework for low carbon hydrogen, we will need to balance policy certainty for investors with adapting and building flexibility to respond to future changes to the energy system. We will use the strategic principles outlined in Chapter 1.5 to inform the ongoing development of the market framework across the value chain.

Supporting innovation for first-of-a-kind projects

We are currently supporting hydrogen innovation through a number of mechanisms including the HySupply competitions, Industrial Fuel Switching competition and Hy4Heat programme. Supporting technical improvements and commercialisation of new hydrogen technologies will remain a key priority as government develops the £1 billion Net Zero Innovation Portfolio. Hydrogen project developers have to date also been able to access government co-investment through the £315m Industrial Energy Transformation Fund, £170m Industrial Decarbonisation Challenge and £10m Green Distilleries Fund which all support deployment of low carbon technologies including hydrogen.

Supporting hydrogen production

Our 2030 5GW ambition represents a step change in the scale of the UK hydrogen economy, and we are developing new policies to support the delivery of this ambition. In the near term, and as set out in Chapter 2.2 and the consultations published alongside this strategy, we are proposing two key interventions that will help to bring down the costs of producing hydrogen relative to high carbon alternatives:

- The **Net Zero Hydrogen Fund**, designed to provide initial co-investment for new low carbon hydrogen production, with the aim of de-risking private sector investment and reducing the lifetime costs of low carbon hydrogen projects;

- Our **Hydrogen Business Model**, to provide longer term revenue support to hydrogen producers to overcome the cost gap between low carbon hydrogen and higher carbon counterfactual fuels, with the aim of enabling producers to price hydrogen competitively and helping to bring through private sector investment in hydrogen projects. **We intend to provide a response to our consultation on a Hydrogen Business Model alongside indicative Heads of Terms in Q1 2022.**

Demand-side interventions: carbon pricing, standards and sector-specific policies

While capital and revenue support for production will help to support investor confidence, it is likely that barriers to the development of the market will remain, most notably on the demand side. These can be mitigated through a range of other decarbonisation policies across different parts of the energy system. For instance:

- **Carbon pricing**, such as through the UK Emissions Trading Scheme (ETS) and Carbon Price Support (CPS), which send clear long-term signals that carbon will become an increasing cost for industry, thus promoting investment in low carbon technologies including hydrogen as a route to reducing these costs. We have already committed to exploring expanding the ETS to the two thirds of UK emissions not currently covered by the scheme as an important means of strengthening this long-term price signal, and will set out our aspirations to continue to lead the world on carbon pricing in the run up to COP26.

- A **Low Carbon Hydrogen Standard**, which can help to support the demand for low carbon hydrogen by providing confidence to end users that the hydrogen purchased is a low carbon alternative to existing fuels. We are also considering whether in time, this could also be used to underpin international trade. We are publishing a consultation on a UK low carbon hydrogen standard alongside this strategy, as explained in Chapter 2.2.

- **Sector-specific policies**, such as the Renewable Transport Fuel Obligation (RTFO) in transport, the Capacity Market (CM) in the power sector, or the Industrial Energy Transformation Fund (IETF) in industry, which can also support the use of low carbon hydrogen for particular sectors.

We will continue to engage with industry stakeholders and monitor progress as the market grows and our understanding of the pathways to CB6 and net zero continues to develop. In doing so, we will consider if further government action is required for the hydrogen market overall to evolve in line with our roadmap, and as we continue to review the existing energy policy landscape for consistency with CB6 and net zero.

Specifically, **we will undertake further work to understand and develop appropriate market frameworks to drive investment and deployment, considering how**

these should evolve over time to bring forward first-of-a-kind and nth-of-a-kind projects across the value chain, and transition to longer term competitive market frameworks. We will aim to publish initial conclusions and proposals in our next strategy update in early 2022.

Taking a whole-system approach

As we do this it may be appropriate to kick start the hydrogen economy through stimulation of early demand from sectors for which hydrogen may not be a significant decarbonisation solution in the longer run. For instance, blending hydrogen into the existing gas network could potentially facilitate access to a significant source of early demand, ahead of longer term decisions of the decarbonisation of heat in buildings (see gas blending box below). Hydrogen storage facilities may also play a role in providing greater demand-side certainty, especially when coupled with flexible power generation, which we will consider further as we assess future commercial arrangements for storage (see Chapter 2.3).

The coordination of supply and demand, particularly the sequencing and geographical location of production and end-users, will also be critical, driven to a large extent by the evolution of the hydrogen networks and storage infrastructure, but also wider system considerations. For instance, hydrogen producers or users in particular locations might provide valuable electricity grid balancing services.

In designing policy, it will be important to not create market distortions that would overly incentivise hydrogen relative to other decarbonisation routes. As and when we design new support schemes, we will need to carefully consider how they interact with the existing policy landscape. **We will work across government to highlight the potential role of hydrogen in the future energy system and consider whether and how this should be reflected in the design of wider energy markets and policies (such as the capacity market or the green gas support scheme).**

Creating a market: Gas blending to facilitate an early use case for hydrogen

Government is considering whether to support blending of low carbon hydrogen into the current gas network, to help with the initial development of the hydrogen economy. The *Ten Point Plan* set commitments to complete necessary testing of blending up to 20 per cent hydrogen into the gas grid by 2023.[72] Similarly, the *Energy White Paper* notes ambitious intentions to enable up to 20 per cent hydrogen blending on the networks by 2023 (subject to trials and testing).[73]

Use of hydrogen in our gas network is not new. Until the late 1960s, most of UK gas was 'town gas', which contained around 50 per cent hydrogen (mixed with methane and carbon monoxide). Town gas was typically manufactured locally from coal or oil, and consequently had a high carbon footprint and significant variability from one town to another.

The discovery of significant reserves of natural gas in the North Sea led to the rollout of an extensive national gas transmission and distribution system, meaning that today our gas system is much larger, more interconnected and better regulated. Today, around 85 per cent of households use gas central heating,[74] and a variety of industrial users have specific gas requirements.

Under the Gas Safety (Management) Regulations 1996, current hydrogen content in the gas networks is limited to 0.1 per cent by volume.[75] A deliberate effort to safely blend new gases into the existing gas network therefore requires evidence gathering and Health and Safety Executive (HSE) approval, prior to any live deployment.

Government and industry must continue to work together to overcome several critical technical, regulatory and commercial hurdles that will confirm whether blending *should and could* be an early use case for low carbon hydrogen.

Safety demonstrations, such as HyDeploy[76] and FutureGrid,[77] are underway to explore the potential for blending at distribution and transmission network pressures, in addition to investigating impacts on end use. The current phases of both trials are due to conclude in 2023. A comprehensive value for money assessment is required to assess the costs and benefits of blending. This will include evaluating crucial timings envisaged for potential future use of 100 per cent hydrogen for heat. The current gas system is not yet designed to accommodate hydrogen. Consequently, government is working closely with key delivery partners to assess the regulatory, physical and system changes required across the gas market to facilitate blending.

While blending could yield potential strategic benefits, some of which may be contingent on wider developments in the hydrogen value chain and existing gas market, there are also limitations. The relative balance between these may change as we continue to understand the pathway to CB6 and net zero, and as the market for hydrogen matures.

Strategic role	Potential benefits	Limitations and contingencies
Supporting low carbon hydrogen production & early development of hydrogen economy	Blending could facilitate access to a significant source of demand for early low carbon hydrogen producers, potentially functioning as a useful sink for excess production (as an 'offtaker of last resort'). We recognise that blending could offer security for hydrogen production investment decisions, by providing a commercial option to sell hydrogen for gas consumer use.	As there are other 'demand offtakers' for hydrogen (such as in industry or power), depending on the blending value for money case, alternative offtakers might provide a preferable longer term use for hydrogen.
Transferable insights for future use of 100 per cent hydrogen for heat	Blending hydrogen into existing gas networks could accelerate some technical, regulatory and commercial changes that may facilitate a smoother transition to the potential use of pure hydrogen as a heating fuel. This might include reforming gas consumer billing methodologies or potentially altering governance of the Gas Safety (Management) Regulations 1996. Blending may also improve consumer awareness of the benefits and ease of using hydrogen as a heating fuel.	A use of 100 per cent hydrogen for heating scenario is still not certain and even if the UK proceeds with this option, further enabling changes would be required across all technical, regulatory and commercial areas.
GHG emissions reductions	Low carbon hydrogen is less carbon intensive than natural gas, and thus blending could help decarbonisation of the existing gas grid in the near term.	Hydrogen has a lower volumetric energy density compared to natural gas. This means that a significantly larger volume of hydrogen would need to be blended and deployed to make substantial carbon savings. Blending is not a sufficient route to long term gas decarbonisation required by net zero.

Government recognises that, should blending be rolled out, industry will need early sight of how it should be implemented. We are proposing five principles for delivery:

- Blending low carbon hydrogen across the existing gas network, or parts thereof, would remain within safe limits set by the HSE (likely up to 20 per cent by volume); and any proposed changes to gas quality and infrastructure would meet all safety requirements.
- Any proposed changes to gas quality and infrastructure should maintain existing system, pipeline, and consumer appliance operability.
- Blending should not prohibit a secure supply of gas for consumers.
- Any costs to consumers should be affordable (ensuring value for money).
- Blending could support initial development of the low carbon hydrogen economy, but blending is not a preferred long term offtaker.

Government, Ofgem, existing gas networks and wider industry must continue to share information and work closely on evidence gathering and aligning understanding on safety, physical roll out models and value for money. Forthcoming actions range from:

- Addressing safety, operability and technical concerns.
- Proposing an optimal, practical model for blending.
- Conducting a value for money assessment.
- Comparing the merit of blending versus other end uses for low carbon hydrogen.
- Creating a regulatory and commercial framework, for example – a new billing methodology.

This is essential work that we will prioritise in the coming years.

If there is a value for money and safety case for blending, government's intention is to enable blending of hydrogen into the existing gas grid at the earliest from 2023, as a measure to help bring forward early hydrogen production.

We will engage with industry and regulators to develop the safety case, technical and cost effectiveness assessments of blending up to 20 per cent hydrogen (by volume) into the existing gas network. Ahead of the completion of safety trials, we aim to provide an indicative assessment of the value for money case for blending by autumn 2022, with a final policy decision likely to take place in late 2023.

Ensuring appropriate funding mechanisms to support a developing hydrogen market

Low carbon hydrogen is currently more expensive than counterfactual fuels, and the additional costs cannot be directly passed onto customers if hydrogen is to be a competitive alternative. Funding must come from elsewhere to make hydrogen production and use commercially viable, and deciding how this is paid for and who bears the cost is a key question that must be addressed. The complex nature of the hydrogen market means that the impacts of a chosen funding mechanism must be considered across a range of different end use sectors and consumers, including their ability to absorb these costs, and the impact that additional costs would have on demand. **Further details of the revenue mechanism, which will provide funding for the Hydrogen Business Model, will be provided later this year.**

2.5.2 Ensuring a supportive regulatory framework

The regulatory framework as it relates to hydrogen is broad and complex, including rules and regulations relating to the environment, safety, markets, competition, planning and specific end uses. While early projects can be expected to operate within existing regulatory regimes, new rules and regulations may be required to facilitate the further expansion of the market and maintain competitive pressure over the course of the 2020s and beyond, especially should hydrogen networks connect to the existing gas network in the future, for instance, to enable blending or grid conversion.

What are we doing to deliver?

Government is working with regulators and industry to develop a common understanding of how current regulation supports or impedes the production and use of low carbon hydrogen – for instance, through the working group on standards and regulations under the Hydrogen Advisory Council. Projects such as HyLaw have analysed the legal and administrative processes applicable to hydrogen in several countries and identified the legal barriers to the deployment of hydrogen applications in the UK.[78]

Through such channels, we are considering both the immediate regulatory barriers to the initial development of the hydrogen economy, but also the broader regulatory framework for hydrogen, and how it will need to evolve as the hydrogen and wider energy markets develop over the course of the 2020s, to the mid-2030s and out to net zero in 2050. This work will allow government to plan and prioritise regulatory changes and provide clarity on the roles and responsibilities of different regulators. In doing so, we will consider and address four overarching and interdependent regulatory issues for the hydrogen economy.

Addressing regulatory barriers facing first-of-a-kind hydrogen projects

First-of-a-kind projects can act as critical innovators in the development of the technologies and policy interventions that will underpin the future hydrogen economy. However, they may encounter unexpected regulatory barriers, for instance relating to safety, planning, licensing or access to end use markets (for example, different regulations and regulators for households versus industry, transport versus heat). Such unforeseen barriers can significantly hinder early project development and related innovation.

Building on initiatives such as HyLaw and the experience of early industrial 'pathfinder' projects (see Chapter 2.4.1), **government will continue to work with industry and regulators in the early 2020s to identify and address regulatory barriers faced by first-of-a-kind hydrogen projects and consider changes needed to unlock hydrogen investment and deployment across the value chain. We will aim to publish initial conclusions and proposals in our next strategy update in early 2022.**

Using regulation to unlock access to new markets for hydrogen

Regulatory changes may also be required to unlock new markets for hydrogen (such as potentially mandating hydrogen-ready appliances in some areas), or to address regulatory barriers that limit the option of low carbon hydrogen (such as changing the Gas Safety Management Regulations (1996) to allow for hydrogen blending into the gas grid).

Government will continue to work with industry and regulators to consider what regulatory changes may be appropriate across the hydrogen value chain, in line with other commitments made in this strategy.

We will also work across government to highlight the potential role of hydrogen in the future energy system and consider whether and how this should be reflected in wider regulatory and policy changes (such as any future changes to the Gas Act 1986).

Identifying who should regulate an evolving future market for low carbon hydrogen, and how and when

As hydrogen networks expand out of initial clusters in the 2020s, and with critical decisions being made on blending hydrogen into the existing gas grid by 2023 (subject to trials and testing) and on the potential for use of 100 per cent hydrogen in heating in the mid-2020s, the nature and scale of hydrogen networks may alter significantly, potentially reaching right into people's homes. This would have important implications for the applicable regulatory and legal frameworks, with bespoke arrangements likely to be required, overseen and administered by new statutory bodies or existing ones with new powers.

The applicable regulations in the initial stages of market and network expansion may need to evolve as the market grows and matures. Identifying when changes are needed to enable the market to progress through phases of integration and expansion will be critical, and likely long lead-in times for regulatory changes will need to be taken into account. While we expect some regulatory changes will be required by the mid-2020s to support early network expansion, the long-term arrangements will likely not be in place until the late 2020s. Working through these issues will be an iterative process, and **we will formalise our engagement through the creation of a Hydrogen Regulators Forum, with representation across the relevant regulatory areas (including environmental, safety, markets, competition and planning).**

Ensuring that the potential role for hydrogen is considered in broader reviews of regulation

Any action to support and frame the hydrogen economy will need to be reflected in the broader energy system. This includes the rules, regulations and governance that guide how the energy system functions. As outlined in the *Energy White Paper*, there are numerous pieces of legislation and guidance that will need to be reviewed as the UK transitions to an affordable, secure and reliable energy system which delivers our net zero ambitions – for instance in relation to gas, electricity, CO_2 transport and storage and planning. **We will work across government and with regulators to ensure that the interlinkages between hydrogen and broader governance and regulatory changes are appropriately considered. We will consult this year on the institutional arrangements governing the energy system over the long term, including system operation and energy code governance.**

Developing a regulatory framework for the hydrogen economy that incentivises investment, provides long term certainty, maintains competitive pressure and supports integration with a wider net zero energy system will take time and work. Government will continue to work with regulators and industry to ensure that this regulatory framework can evolve over time in a way that supports our 2030 ambition and positions the hydrogen economy for scale up beyond this for CB6 and net zero.

2.5.3 Raising awareness and securing buy-in

Hydrogen has been used in the UK for many years, as described in Chapter 1, but its future role will be very different. Many potential users are not yet aware that hydrogen could be a low carbon solution for them. Even those who are aware would not find it easy to identify a reliable source of hydrogen, or its cost and carbon intensity. Similarly, many of the technologies users would need to switch to hydrogen, such as boilers and trucks, are not yet commercially available. This means that a critical part of our action in the early 2020s to create the market for hydrogen will be to ensure that energy consumers and businesses understand the potential of low-carbon hydrogen and how it operates, and to provide assurance that its development and rollout are underpinned by systems and frameworks appropriate for any energy carrier and related technologies.

What are we doing to deliver?

The transition to any new low carbon technology brings both opportunities and challenges for different stakeholders. We will draw on lessons learnt from raising awareness of other new and low carbon technologies, such as smart meters and electric vehicles, to ensure businesses and consumers can access and drive forward the low carbon hydrogen economy.

Additionally, we will work with industry to maximise the positive outcomes for the climate and environment that the growth of a low carbon hydrogen economy could bring, including for air quality, and will ensure that any potential trade-offs between the two are minimised. For example, we will support industry to work with the Environment Agency and other regulators to reduce the creation of nitrogen oxide (NOx) emissions that the combustion of hydrogen in an engine or boiler creates, helping to deliver on our air quality targets to deliver cleaner air for all.

We recognise the need for targeted engagement going forward to understand and work through key priorities for industry, businesses, civil society and households to secure buy-in and enable the use of low carbon hydrogen across different parts of the energy system. To help with this, we have established the Hydrogen Advisory Council which reflects a cross section of expertise on low carbon hydrogen across the value chain. We are also engaging with a wide range of stakeholders outside of this forum, recognising the importance of different perspectives in shaping this nascent policy agenda.

Broad and early stakeholder engagement allows for important public discourse on different aspects of our 2030 ambition and broader plans to deliver CB6 and reach net zero. We will continue to engage citizens and use the expertise of others to inform policy development by considering conclusions of citizen's assemblies which provide feedback from a representative sample of the UK (such as Climate Assembly UK's report, 'The Path to Net Zero).

This approach has already yielded important insights with technologies associated with low carbon hydrogen production. For example, in collaboration with UKRI and Sciencewise, last year we commissioned a public dialogue study to explore citizens' perceptions towards CCUS at both a local and non-local level. Public engagement will help us to understand different perspectives towards the substantial infrastructural and behavioural changes that are needed to decarbonise our energy system over the next 30 years, including in relation to the potential role of hydrogen.

While we recognise the crucial role that government can play in raising public awareness of the importance of decarbonising our energy system, including through low carbon hydrogen, we are mindful that this will be most effective carried out collaboratively with local communities to understand the priorities of and opportunities for different stakeholders. These groups are well placed to help us assess the fairness and affordability of different policy decisions to support the hydrogen economy as it grows.

Regulators and industry will also be engaging in activity to raise awareness for potential new uses case for hydrogen. Through the safety workstream of the Hy4heat programme, government is working with HSE on a project to assess the safe use of hydrogen gas in certain types of domestic properties and buildings (detached, semi-detached and terraced houses of standard construction), as part of preparation for the first community trials using hydrogen as a heating source.

The Hy4heat programme, in collaboration with NGN and Cadent, is also supporting the construction of two unoccupied homes in Gateshead that will feature Hy4Heat-funded prototype boilers, hobs, cookers, fires and meters to showcase the potential use of 100 per cent hydrogen for domestic heating. Members of the public will be able to see how these appliances compare with like-for-like ones that run on natural gas. Building on this learning, we are delivering a programme of work to assess the feasibility, costs and consumer experience of 100 per cent hydrogen heating (see Chapter 2.4.3). These include consumer trials which will be key to understanding how consumers could experience hydrogen heating.

The government sees this strategy as a significant step towards improving awareness, both of the potential role that hydrogen can play in decarbonising our energy system, and of the challenges involved in bringing this about. We will continue to explore opportunities for dialogue and information sharing on the challenges and opportunities for low carbon hydrogen, including in relation to other low carbon technologies. Public engagement is an important priority for government in the run up to COP26, and as we look to publish our forthcoming Net Zero Strategy.

Chapter 3: Realising economic benefits for the UK

Key commitments

- We will prepare a **Hydrogen Sector Development Action Plan**, including for UK supply chains, by early 2022.
- We will establish an **Early Career Professionals Forum** under the Hydrogen Advisory Council.
- We will support hydrogen innovation as one of the ten key priority areas in the **£1bn Net Zero Innovation Portfolio**.
- We will work with the Hydrogen Advisory Council Research & Innovation Working Group to develop a UK **hydrogen technology R&I roadmap**.
- We will deliver as one of the co-leads of Mission Innovation's new **Clean Hydrogen Mission**.

The UK's geography, geology, infrastructure and expertise make it particularly suited to rapidly developing a low carbon hydrogen economy. This offers a great opportunity for companies, communities and individuals. This chapter sets out our plans to maximise the economic benefits to the UK from this shift – supporting jobs and regional growth, making the best of our research and innovation strengths, and ensuring that businesses across the country are in a position to tap into the growing global hydrogen market.

The hydrogen economy is in the very early stages of development in the UK and globally. This presents an opportunity to put a focus on economic benefits at the heart of our approach from the outset as we look to deliver our 2030 ambition and contribute to achieving our CB6 and net zero targets.

We can draw on lessons from the development of other low carbon technologies to ensure that our companies, communities and individuals can be at the forefront of this opportunity – promoting world-class, sustainable supply chains and creating high value, skilled jobs. We will also make the UK an attractive place to invest in hydrogen and seek to maximise the export potential of our technologies and expertise. In doing so, we will support the government's *Plan for Growth*, driving local and regional opportunities, and helping to level up across our industrial heartlands and throughout the UK.

We will work in partnership with industry, the academic and research and innovation community, devolved administrations, local authorities, workers and civil society to harness the best of the UK's skills and capabilities. We will share these with – and learn from – expertise elsewhere, and capitalise on our world-leading academic and industrial research and innovation base.

Government will work to bring together the various existing and emerging businesses critical to enabling the hydrogen economy. Some of these will be well-established firms in the transport, industrial and oil and gas sectors; others will be emerging innovators designing and building fuel cells, electrolysers, and new components for the distribution and storage of hydrogen.

We want to see UK companies at the forefront of the growing global hydrogen market, and we are developing policy that will attract and secure investment in a pipeline of British projects, driving rapid progress to foster our exportable strengths and get ahead in the global market.

Analysis[79] suggests that in 2030 the UK hydrogen economy could be worth £900m and support over 9,000 jobs. Around a quarter of these jobs could be driven by British supply chain exports.

By 2050, under a high hydrogen scenario, the hydrogen economy could be worth up to £13 billion and support up to 100,000 jobs, with exports growing in relative importance.

3.1 Building a world class supply chain

Government will work to promote the growth of world-class, sustainable supply chains to underpin the deployment of early commercial scale UK hydrogen projects over the 2020s, and to be ready to support expansion of the sector from the 2030s.

The UK is well positioned to grow and develop supply chains across the full low carbon hydrogen value chain, from production, through to transportation, distribution and storage, and across various end uses in industry, power, heat and transport. These supply chains will be vital to underpinning our vision of growth in the hydrogen economy across the 2020s, and to position it for significant ramp up in the 2030s in line with CB6 and net zero.

To make sure that the UK can capitalise on these opportunities, we have carried out an initial assessment of current UK low carbon hydrogen supply chain capability and strengths, to identify opportunities and barriers to companies being able to thrive and support the full hydrogen value chain as it develops in line with our 2020s roadmap (see Figure 3.1 below).

Seizing the opportunity

We will work with industry, academia and other stakeholders to build on insights from other energy sectors to assess what actions government, industry and the research and innovation community could take to seize the supply chain opportunities presented by the early development of a low carbon hydrogen economy, and for UK businesses to position themselves at the forefront of the hydrogen economy. **We will set out more detail in a Hydrogen Sector Development Action Plan by early 2022.**

We will learn lessons from the development of the UK's world-leading oil and gas sector, driven in part through measures introduced in the 1970s. Similarly, we will draw on the expansion of other low carbon sectors, such as offshore wind, where early opportunities for UK investment, regional growth and job creation were not built in and capitalised on from the start, even while the UK has become a world leader in deployment.

Figure 3.1: UK supply chain development over the 2020s

Early 2020s	Mid 2020s	Late 2020s onward
• British supply chain companies lay the foundation to support our vision for the hydrogen economy in the near and long term. • The UK builds on its strengths in electrochemical technologies (fuel cells and electrolysers). British companies are exporting these technologies to markets in Europe and SE Asia. • Domestically, these are deployed in small-scale electrolytic production projects and in transport. • World-leading supply chains supporting other sectors, such as oil and gas, pivot towards supporting the hydrogen economy, offering opportunities to make use of UK skills, capabilities and technologies.	• The UK has the opportunity to deploy blue hydrogen projects, linked closely to the development of CCUS supply chains, as set out in the CCUS roadmap, taking advantage of UK CO_2 storage potential. • Supply chains across the value chain gear to support scaled-up deployment, and are positioned to support future growth of the domestic hydrogen economy. • UK continues to build on its world-class innovation. For instance, domestic hydrogen boilers which have the potential to serve the domestic market.	• Continued growth in low carbon hydrogen production, complemented by growing UK strengths in distribution and end-use markets such as in vehicles and industrial applications. • UK takes advantage of its natural assets, for instance in seizing opportunities for hydrogen storage. • UK supply chains and skills base are well positioned to support accelerated domestic deployment in support of net zero in the 2030s and beyond, and to seize opportunities to export technology, expertise, and hydrogen itself. • The hydrogen sector plays an important role in supporting other sectors, such as construction, automotive and steel, to anchor their supply chains in the UK by making it possible for them to decarbonise and develop a low-carbon proposition that will ultimately be exportable.

- Throughout, the breadth of the hydrogen value chain offers opportunity to seize on UK expertise in other sectors, such as high-end manufacturing, oil and gas, renewables, chemicals, safety, engineering, procurement and construction management (EPCm) and our functional strengths of planning, legal, professional and financial services.

In doing so, we will also focus on developing the next generation of technologies that will help fill the gaps in the supply chain, reduce costs and put the UK on a footing to grow at scale in the 2030s.

This work will include supply chains that currently support high carbon industries, which have the opportunity to pivot and build on their base capabilities and expertise to meet the needs of the UK hydrogen sector, as well as internationally. This will not be limited to CCUS-enabled hydrogen but will include strengths in process engineering, offshore engineering and re-purposing of offshore assets, and gas safety management. The new UK Energy Supply Chain Taskforce[80] will focus on ensuring UK supply chain companies can take advantage of clean growth opportunities in the UK and overseas.

The oil and gas sector's voluntary commitment through the *North Sea Transition Deal* to aim towards 50 per cent local content across the lifecycle of projects, including for hydrogen, will help safeguard long-established UK supply chains – and world-leading skills, capabilities, and innovation – that will be crucial to realising both the decarbonisation and economic benefits of the UK's transition to net zero.

Our expectation of industry

We will seek to introduce economic benefit assessments into the Net Zero Hydrogen Fund and Hydrogen Business Model. Consultations on the NZHF and the Hydrogen Business Model are taking place alongside the publication of this strategy. Our expectation is that hydrogen developers across the full value chain will work to ensure that competitive UK companies, including SMEs, are in a fair position to bid into hydrogen projects.

In establishing these assessment criteria, we will recognise that the hydrogen market is in its infancy and that intervening too firmly for first-of-a-kind projects could stifle cost-competitive growth. Over time, however, we anticipate that hydrogen will follow in the footsteps of established sectors like offshore wind and oil and gas to be able to put in place bold commitments to UK content.

Such measures might follow along the lines of the changes to the renewables supply chain plans being introduced through the Contract for Difference (CfD) allocation process. These will require a supply chain plan to be submitted to the Secretary of State before participation in CfD auctions, building on the offshore wind sector's voluntary commitment to 60 per cent local content through the *Offshore Wind Sector Deal*.

We will actively monitor the extent to which competitive UK businesses are benefitting as the hydrogen sector matures. If necessary, we will consider what options are open to ensure a fair playing field that includes UK businesses. **We will set out more detail on this in our Action Plan.**

Project visibility

To be successful, low-carbon hydrogen supply chains will also need to have good visibility of the opportunities ahead, across the full hydrogen value chain. **We will work with industry to improve visibility of the low carbon hydrogen project pipeline across the supply chain, learning from the success of initiatives in other low carbon sectors.**

3.2 Creating jobs and upskilling industry

Developing a hydrogen economy is a key component of the opportunity offered by our net zero target to transform the UK's industrial regions, attract investment, and create secure, good quality green jobs across the UK. Developing this nascent sector will require existing and important new skills to be available in the right place at the right time. We will work with partners to identify skills requirements and intervene if necessary, including to support workers from transitioning high carbon sectors.

Creating a successful hydrogen sector could support 9,000 direct jobs across the UK by 2030, with up to 100,000 supported directly by 2050.

These jobs, with additional indirect and induced[81] employment benefits, will help drive local economic growth and support the delivery of government's commitment to level up the UK.

Ensuring the right skills are available in the right place at the right time

Ensuring that the UK has the right skills and capabilities will be critical to achieving our hydrogen ambition.

As part of our work to develop the low carbon hydrogen sector, we will assess the opportunities for hydrogen employment across the UK. Over the next year, in collaboration with stakeholders, we will work to understand the profile of required skills over the 2020s and into the 2030s, in line with our roadmap set out in Chapter 2.1. **We will work with industry, trade unions, the devolved administrations, local authorities, and enterprise agencies to support sustained and quality jobs and ensure that there is effective and targeted investment in relevant skills.**

Creating good-quality[82] jobs in the hydrogen sector, particularly where these are in our industrial heartlands, will make a significant contribution to ensuring people do not have to relocate to succeed. As set out in the *Plan for Growth*, we will catalyse centres of excellence and help people connect to opportunity as a way to drive regional and local growth.

We believe that initiatives to invest in growing the skills base are best when led locally, to ensure skills are tailored to demand. The government's *Skills for Jobs: Lifelong Learning for Opportunity and Growth White Paper*[83] recognises that there are skills gaps at higher technical levels which might affect our ability to grow the green economy. Investing in these skills at both a local and a national level will be critical. **We will work with industry, education providers and local and regional authorities to explore opportunities for relevant skills programmes, including apprenticeships and re-skilling programmes.**

In doing so, we will work to ensure that the recent recommendations from the *Green Jobs Taskforce*[84] will inform the UK's forthcoming Net Zero Strategy, many of which are pertinent to the hydrogen sector. These recommendations aim to:

- Ensure the UK has the immediate skills needed to kick-start and deliver a green recovery.

- Develop a long-term plan to chart out skills requirements ahead of net zero.

- Ensure jobs in the green economy, such as the hydrogen sector, are high quality and inclusive.

- Support opportunities for workers in high carbon sectors, supporting them through the transition to zero carbon sectors.

To attract and retain talent, we will also work with the sector to ensure that equality of opportunity is considered from the outset. We are mindful of the *Offshore Wind* and *Nuclear Sector Deals'* diversity ambitions[85] and see no reason why the hydrogen sector cannot be at least as ambitious.

In support of this, **we will set up an Early Career Professionals Forum under the Hydrogen Advisory Council.** As an emerging sector, it will be important to ensure that early career professionals in the hydrogen economy are engaged and able to advise government.

Re-skilling workers from high carbon industries

Hydrogen provides an opportunity for those who have previously worked or are currently working in high carbon sectors to transition to support the green industrial revolution.

As an example, Oil & Gas UK has estimated that, between 2018 and 2030, the number of jobs directly and indirectly supported by the UK's offshore oil and gas industry could reduce from 147,000 to around 105,000.[86] Many skills in this industry will be transferable to clean growth industries, and hydrogen will provide significant opportunities – including project management, process engineering, repurposing of infrastructure and gas safety.

The recent *North Sea Transition Deal*[87] committed the government to continue to champion the role of the oil and gas sector and its workforce in the energy transition, supporting work on the sector's Integrated People and Skills Plan. In March 2021, the government announced £27m of funding for the Aberdeen Energy Transition Zone and £5m for a 'Global Underwater Hub', which will help support the industry's transition to renewable and low carbon energy technologies such as offshore wind, hydrogen and CCUS. We will work to support other initiatives in relevant sectors, and will support work to ensure portability and mutual recognition of professional qualifications to enable people to transition to new sectors such as hydrogen without re-certification.

We will work with industry and others to support workers in need of training so that they can access the new jobs that will become available. We will also work collaboratively with industry and education providers to explore what high-intensity up-skilling and re-training opportunities could be provided.

We will continue to support the work of the Energy Skills Alliance (ESA) established in 2019, which is working to produce a clear forecast of energy skills in the short term, deliver

an integrated energy apprenticeship scheme and develop a roadmap for aligning training and standards. The Hy4Heat programme has also developed a framework for skills accreditation for heating engineers working with hydrogen.

Our expectation of industry

We are aware of – and welcome – several initiatives being taken forward by developers and industry to support skills development. Many of these are tied to emerging hydrogen and CCUS clusters, providing opportunities for the UK skills base to thrive in industrial regions across the UK and maximising opportunities for jobs in the sector.

It is our expectation that the hydrogen sector, as it grows, will invest in growing its skills base and in supporting good-quality jobs, with equality of opportunity as a core focus from the outset.

To support this in the near term, we will seek to introduce measures through the Net Zero Hydrogen Fund, and in due course we would expect to do the same for the proposed Hydrogen Business Model. Our aim is to incentivise project developers to demonstrate how they intend to grow relevant skills and support good quality jobs and equality of opportunity throughout the supply chain.

We will continue to monitor this as the hydrogen sector matures and consult if necessary to identify barriers to sufficient private sector investment in growing the UK skills base and supporting good quality jobs and EDI.

3.3 Maximising our research and innovation strengths

Supporting research and innovation (R&I) will be key to cost-effective acceleration of the UK hydrogen economy and ensuring it can create and stimulate economic opportunities where the UK has expertise. We will take a whole-system approach to R&I throughout the 2020s to be able to deploy and integrate hydrogen technology and systems holistically in the context of wider social, environmental and economic developments.

The UK's existing hydrogen research base is strong. As the second most active country in hydrogen and fuel cell research in Europe, we are well placed to capture part of the global innovation potential in the hydrogen value chain and position the UK as a leading hydrogen technology developer.

Enhancing the ability of the UK R&I ecosystem to support commercialisation

We recognise that the technology journey – from idea to commercialisation – seldom moves from discovery research through to development (learning by research) and demonstration (learning by doing) in a linear way. It is an iterative process which must be further enabled to support the de-risking of current technology while next generation technology is developed.

UK government investment in internationally recognised hydrogen R&I projects has already enabled the development of many key hydrogen technologies, including those promoted by a handful of UK firms, such as Bramble Energy, Ceres Power and ITM Power, who have positioned themselves at the forefront of the global shift to hydrogen.[88]

We want to see others follow in the footsteps of these companies, for example by making the most of opportunities such as our **£1 billion Net Zero Innovation Portfolio (NZIP)**, which has made hydrogen one of ten key priority areas. NZIP itself represents a doubling of the UK's £505 million Energy Innovation Programme over the past five years. We aim for this new funding to be complemented by up to £3.5 billion of matched and follow-on funding from the private sector. **One of the first schemes to be launched under the NZIP is the £60 million Hydrogen Supply 2 Competition**, which will support the development of a wide range of innovative low carbon hydrogen supply solutions in the UK, and identify and scale up more efficient solutions for making clean hydrogen from water using electricity.

To provide crucial long-term certainty for researchers and innovators, we have also already committed to increasing our investment in research and development (R&D) to 2.4 per cent of GDP by 2027 and to increasing public funding for R&D to £22 billion per year by 2024. This will further boost the UK R&I ecosystem, including hydrogen-related activity.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Public sector funding is often key to leveraging private sector investment in innovation, and even more so in the context of unlocking commercialisation and creating a market for hydrogen. **We will work with the Hydrogen Advisory Council and other partners to better understand the scale, scope and type of private sector investment into hydrogen R&I in the UK, and how it can be further promoted.** Our new Innovation Strategy, which will be published later this year, will further outline how we intend to promote private sector investment in R&I more broadly in the UK.

With such a critical role to play in enabling the UK hydrogen economy, it is important that a joined up and strategic approach is taken to hydrogen R&I investment and prioritisation. Government has already established governance mechanisms through a Net Zero Innovation Board to ensure a coordinated, strategic approach to R&D and demonstration funding across public funding bodies, and to enhance the alignment of public and private sector innovation in support of net zero. Building on this, **we will work with experts, including through the newly established R&I working group under the Hydrogen Advisory Council, to develop a strategic and cross-cutting Hydrogen R&I Roadmap to inform public and private sector R&I investment and prioritisation.**

UK R&I in the global landscape

We recognise that the UK's world-leading R&I sits at the heart of a global network of excellence: UK expertise both benefits from and drives forward advances beyond our own borders. We believe that by engaging actively and openly to share research, progress in R&I can be accelerated and its benefits maximised.

We will use our role as one of the co-leads of Mission Innovation's new Clean Hydrogen Mission – and coordinator of its R&D pillar of activities – to champion this approach from the top down. Our commitment to the Mission affords us a unique opportunity to showcase UK R&I expertise and to leverage its outputs to spur further technological progress, and ensure innovation is commercialised in a way that can push forward hydrogen technology development. In Chapter 4 of this strategy, we set out how we will work to ensure this 'push' boost of R&I progress is joined-up with policy, regulatory and demand-focused actions that 'pull' its contributions through the value chain.

We will also continue to foster collaborative international research and information exchange on the production and deployment of hydrogen as a global energy carrier, through our active membership of the International Energy Agency (IEA) Hydrogen Technology Collaboration Programme (Hydrogen TCP).[89]

3.4 Attracting investment

The development of a UK hydrogen economy fit for net zero presents unique opportunities for investment in UK projects, associated infrastructure, supply chain companies, technologies and innovation. We will work to create an attractive environment to secure the right investment in UK projects, with benefits to UK business and communities.

We are confident that UK strengths and assets, including potential for rapid scale up across the domestic value chain, coupled with our strategic and policy approach, will create the right conditions to unlock the significant scale of private investment that will be needed to develop and grow the UK hydrogen economy. The development of other clean growth energy industries can give a sense of the scale of investment needed to develop and grow new low carbon sectors such as hydrogen: for example, according to Wind Europe[90] over the ten years to 2020 the UK leveraged €56 billion (around £47 billion) in our world-leading offshore wind industry, almost half of all European investment in the sector.

As a start, the *Ten Point Plan* outlined that over £4 billion of private investment could be unlocked over the 2020s, positioning the UK hydrogen sector to deploy at scale in the 2030s and supporting our ambitions in the context of the growing global market. Alongside this strategy, we are consulting on the primary means to stimulate deployment of – and investment in – hydrogen projects through the Net Zero Hydrogen Fund and the proposed Hydrogen Business Model.

The new UK Infrastructure Bank[91] launched in June this year will provide leadership to the market in the development of new technologies including hydrogen, particularly in scaling early-stage technologies that have moved through the R&D phase. The Bank will have an initial £12 billion of capital, and will invest in local authority and private sector infrastructure projects, as well as providing an advisory function to help with the development and delivery of projects. Through these investments the Bank will 'crowd-in' private investment to accelerate our progress to net zero whilst helping to level up across the UK.

The government has also established a new Office for Investment (OfI), which will support high value investment opportunities into the UK which align with key government priorities

– including the hydrogen sector and associated infrastructure – to drive economic recovery and growth across the UK, as well as advancing R&D. We will work closely with the OfI to support the aims and direction set out in this strategy.

We will also continue to champion the UK hydrogen sector, technologies and projects through our world-class UK trade networks, promoting opportunities for foreign investment.

Through these and our ongoing engagement and policy activity, we will continue to work with the investment community to support investment across the hydrogen value chain and its supply chains, with a view to ensuring that the UK hydrogen sector remains a world-class investment case.

3.5 Realising export opportunities

The green industrial revolution has created a once-in-a-generation opportunity for the UK, as well as globally. We will capitalise on our strengths, skills, capabilities, technologies, innovation and investment to position UK companies to springboard into the expanding global hydrogen economy.

Our vision is clear: maximise the investment, growth and export potential of the green industrial revolution. We want to see a lasting and sustainable clean energy sector that can exploit global clean growth opportunities such as those associated with low carbon hydrogen. This will, in turn, support the broader sustainability of the sector and drive down costs.

Analysis suggests that around a quarter of UK jobs in the hydrogen sector, and around 30 per cent of economic opportunity, could be driven by exports by 2030, with these growing in relative importance by 2050. The UK is already an exporter of fuel cell and electrolyser technologies, and our world class engineering, procurement and construction management (EPCm) services sector is well geared to support international opportunities

as the global hydrogen economy grows. Our regulatory framework and decades of experience in gas management and safety are strengths from which the rest of the world can learn and which we are well geared to support internationally.

While our focus in the near term will be on securing domestic deployment of both electrolytic and CCUS-enabled hydrogen projects, we expect that through this UK companies will be increasingly well-positioned to seize opportunities in other markets. We are already working through UK Export Finance, the UK's export credit agency, to support UK hydrogen companies to seize such opportunities – with £2 billion earmarked to finance clean growth projects overseas to create export opportunities for British businesses. UKEF is able to provide favourable financing terms for clean energy projects, as well as working capital and contract bond support for exporting SMEs in the clean growth sector.

New trading relationships will offer further avenues for our businesses to experience the benefits of exporting. We will seize the opportunities for the UK hydrogen sector presented by Global Britain as we advance new Free Trade Agreements.

To help make the most of these opportunities, we will look to work with countries that, like the UK, have an established oil and gas sector that can transition to a low carbon future through hydrogen, sharing learning and establishing common investment and export opportunities.

We will also look to position the UK so that it is able to seize opportunities to export hydrogen itself. A further export opportunity will lie in ammonia produced from low carbon hydrogen, building on trade links that exist for high carbon ammonia today. To put the UK in a position of strength to unlock and benefit from these opportunities for the longer term, we will work to identify any necessary requirements, such as certification, and any constraints, for instance around ports and infrastructure.

The Department for International Trade (DIT) is uniquely placed to promote UK businesses and associated supply chains to access global opportunities, working in 117 separate overseas markets.

DIT works to connect businesses to encourage exporting globally. Its staff use their local expertise, networks and government-to-government relationships to reduce market access barriers for UK businesses and connect businesses with overseas buyers. DIT can link UK-based engineering expertise to emerging global CCUS opportunities, providing intelligence on projects and advice on the supply chain value to the UK. It can also connect the UK industrial clusters to overseas projects.

We are clear that by working closely with industry, academia, and other stakeholders to foster a strong UK low carbon hydrogen sector; create jobs and develop relevant skills and capabilities; and exploit our world-leading innovation, investment and export opportunities, we will position the UK to take a clear global leadership role in hydrogen. The next chapter sets out how we will work with our international partners to help unlock the economic and decarbonisation benefits of hydrogen for the UK, while supporting the scale up of a global hydrogen economy.

Chapter 4:
Demonstrating international leadership

Climate change is a global challenge, and requires a global response. The UK leads the world by example – we were the first major economy to legislate for net zero, and are achieving larger and faster emissions reductions than any comparable economy. The ambitions and commitments set out in this strategy demonstrate our similar determination to develop a low carbon hydrogen economy that will be a key part of our transition to net zero. We are equally determined to play a key role in international collaboration – learning from others and sharing our experience and expertise to help scale up further and faster – so that low carbon hydrogen can help with the wider global transition to net zero.

Coordinated international action on the deployment of low carbon hydrogen technologies will make the transition to net zero faster, easier and cheaper for all. Governments have a crucial role in supporting the coordination of the 'push' and 'pull' needed to develop and then move these technologies into the marketplace, ensure safe deployment and support early demand. By collaborating, we can accelerate progress towards these goals.

Today, low carbon hydrogen technologies remain at a relatively early stage of deployment. This makes international collaboration especially important, to help mitigate first-mover risks and create larger shared markets for the deployment of low carbon hydrogen. The UK is keen to work with other leading hydrogen proponents, both to share our own expertise, and to learn from the experience and knowledge of others. We will take an open and active approach to hydrogen collaboration and cooperation. We believe that:

- By sharing the outcomes of cutting-edge research, we can accelerate the supply 'push' of technological developments and cost reductions needed to allow production and deployment across sectors at scale.

- Through developing common technical and emissions codes and standards, we can support economies of scale – and facilitate a truly global market, with trade, energy security and climate benefits.

- By joining up policy and regulatory activity, we can expedite the creation of markets for low carbon hydrogen, 'pull' forward innovation and investment, and lay the groundwork for an integrated, competitive global hydrogen market.

While we recognise that the global market for low carbon hydrogen will take time to mature, the recent proliferation of national strategies and private sector commitments reflects substantial international ambition. The IEA estimates that in a scenario in line with the Paris Agreement, global low carbon hydrogen demand could reach 2,000TWh in 2030, and 10,500TWh in 2050.[92] In this scenario, hydrogen could meet seven per cent of final energy consumption and deliver 1.6 $GtCO_2$ per year of greenhouse gas abatement in 2050.[93] Other analysis suggests demand could be even higher: BNEF estimate that in a scenario with a strong policy framework supporting hydrogen, demand could reach 27,400TWh by 2050, meeting 24 per cent of final energy usage.[94] These projections underline hydrogen's potential to make a key contribution to global net zero. We must act together now to fully realise that potential.

The UK in international partnerships

The UK plays an active role in many of the key institutions driving multilateral collaboration on hydrogen innovation, policy and standards. These include Mission Innovation (MI), the Clean Energy Ministerial (CEM), the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE), the Hydrogen Energy Ministerial, the International Energy Agency (IEA) and the International Renewable Energy Agency (IRENA).

The UK co-leads the MI Clean Hydrogen Mission, launched in June this year with a goal to foster innovation gains that enable clean hydrogen end-to-end costs of 2 USD/kg in the most competitive regions by 2030. This end cost is achievable, with production costs of USD 1.6-2.3/kg projected by 2030 for CCUS-enabled and electrolytic hydrogen in average regions respectively.[95] The Mission's focus on aligning and targeting innovation funding and research and demonstration programmes towards cost reduction across the supply chain

will help accelerate the development of a comprehensive, international value chain. We will continue to drive global collaboration through MI that facilitates these cost reductions, recognising that this will help accelerate global low carbon hydrogen deployment and the decarbonisation and economic benefits it brings. We are also a core member of the MI Zero Emission Shipping Mission, which aims to have at least 5 per cent of the global deep-sea fleet running on zero-emission fuels such as low carbon hydrogen, green ammonia, green methanol and advanced biofuels by 2030.

We will complement the work of the MI Clean Hydrogen Mission through participation in other forums. We are committed to driving implementation of the 'Tokyo Statement' and Global Action Agenda developed under the Hydrogen Energy Ministerial, whose activities are aimed at promoting hydrogen deployment and encouraging better coordination amongst member countries. We are a member of the CEM Hydrogen Initiative, and will champion its efforts to raise international policy ambition and advance low carbon hydrogen deployment at scale. We will continue to participate actively in IPHE discussions that bring together policymakers and stakeholders in pursuit of regulatory, standards, safety and education objectives, and where we are already contributing to exploring the requirements for future rules governing trade in hydrogen.

These partnerships are making strong progress, but we believe that together, we can go further. The UK will work with partners to strengthen the alignment of individual strands of international collaboration, seeking to develop a globally coordinated 'push-pull' strategy to drive development and deployment of low carbon hydrogen as swiftly and efficiently as possible. Governments are uniquely placed to support both innovation and deployment of technologies to increase supply ('push') and demonstrate and incentivise demand ('pull'), stimulating further private sector investment in research and innovation, production and end use. With strengths across the hydrogen value chain from research to commercial actors and a strong global network, the UK is well placed to work with other leading hydrogen proponents to galvanise this enhanced activity.

We will use our 2021 Presidency of the G7 and co-Presidency of COP26 to advance these international efforts. **Through the G7, we will reaffirm the importance of low carbon hydrogen in the clean energy transition, and seek commitments to increase its production and deployment.** This will support the establishment of a future international hydrogen market, based on recognition of the job-creation and sustainable growth potential of low carbon hydrogen.

Through our global climate leadership, including through our co-Presidency of COP26, we will seek to bring together public and private actors who recognise the crucial role that hydrogen can play in tackling emissions and unleashing clean growth, to facilitate greater coordination and progress across international hydrogen innovation, deployment and policy activity. This approach will include developing countries, and both public and private sector initiatives – sending a clear signal about hydrogen's place in the future global energy mix to give investors and innovators across the value chain confidence, certainty and clarity.

Opportunities for bilateral and regional collaboration

Alongside multilateral collaboration, we are keen to work with key partner countries to develop shared research and innovation activities, complementary policy frameworks and future trade opportunities. We recognise that, in cases of particularly well-matched hydrogen interests or shared challenges, more specific and in-depth collaboration can build on and complement the work of multilateral forums. We will embrace these opportunities.

Working with our North Sea and European neighbours will be key to developing common approaches that will support UK hydrogen investment and facilitate regional trade through interconnectors, pipelines and shared infrastructure. Opportunities include:

- Activities which build on, and complement, multilateral activities. For example, as co-leads of MI's Clean Hydrogen Mission, the UK and European Commission – and individual European partners – could expand on its work on regional value chains.
- Collaboration with North Sea partners to realise the region's potential significance for hydrogen production, storage and transportation, including facilitation of future North Sea trade.
- Activity under Horizon Europe. The UK played a strong role in the Fuel Cells and Hydrogen Joint Undertaking (FCH JU), and will continue to make an active contribution to the Clean Hydrogen Partnership for Europe.

We will also continue to work with key global partners to develop our respective hydrogen economies and establish a global hydrogen market. Opportunities include:

- Joint research and innovation, especially where we share common interests – such as in decarbonising industrial sectors – or hold complementary expertise.

- Developing common regulatory approaches and other policies where appropriate – including by pooling insights on policy development and the feasibility of new use cases.

- Facilitating long-distance trade in hydrogen. As a leading maritime nation, the UK is well-positioned to build on existing trade in ammonia and to develop new trade routes in hydrogen derivatives to realise global trading opportunities.

Ensuring fair distribution of shared gains and supporting hydrogen through trade agreements

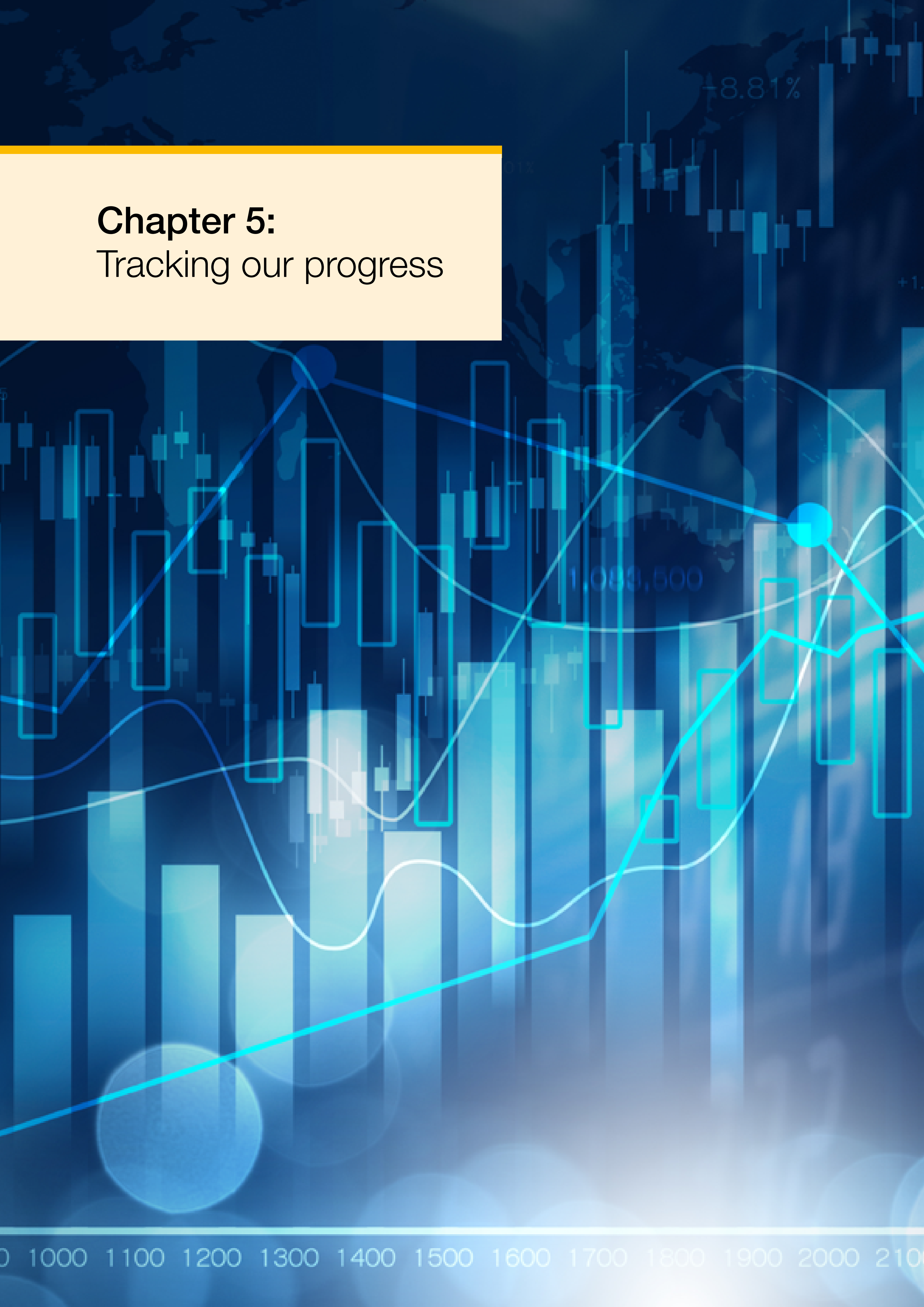
We will continue to support hydrogen-enabled low carbon transitions and share relevant UK expertise through Official Development Assistance, building on our work to date. This includes support to develop hydrogen roadmaps in Mexico and South Africa through the UK Partnering for Accelerated Climate Transitions programme, and UK Clean Energy Innovation Facility support for scoping green hydrogen production, priority uses and export opportunities in Morocco. Under our international CCUS programme, a global decarbonising natural gas study is analysing the use of CCUS across the natural gas value chain, including for hydrogen generation.

The UK will also use its position as a leading advocate for free trade to galvanise action on hydrogen. We will seize opportunities, including through Free Trade Agreements and our place in the World Trade Organization, to support the development of a global low carbon hydrogen market. This means ensuring an attractive trade regulation environment, reducing technical barriers to trade, and facilitating investment in hydrogen technologies and trading infrastructure. This approach is a natural extension of the support we will provide to the UK's own hydrogen sector, as set out in Chapter 3, and will allow our world-leading commercial sector to fulfil its potential to contribute to the global deployment of clean energy technologies.

Climate champion, proven partner: primed for hydrogen

The UK has a proven record of leadership in developing and deploying innovative clean energy solutions, supporting research, development and deployment activities that bring down costs, and creating the policy frameworks to enable scale-up. This has resulted in rapid decarbonisation while supporting clean growth. We have consistently shared our experience and lessons with the world, and sought to learn from and build on the achievement of others in turn. Our net zero ambition and collaborative approach will ensure that by 2030, the UK can stand with our partners at the heart of a new global low carbon hydrogen success story.

Chapter 5:
Tracking our progress



This strategy sets out the key steps needed in the 2020s to deliver our 5GW ambition by 2030 and create a thriving low carbon hydrogen economy in the UK to support our CB6 and net zero targets. We have detailed a number of commitments and actions that we will take to make this happen. The strategy is an ambitious, first of its kind document for hydrogen in the UK. It signals our long-term commitment to developing low carbon hydrogen as a credible, safe and affordable energy option in our journey to net zero.

The UK Hydrogen Strategy outlines a range of policies and initiatives already underway, and other commitments which we will take forward over the coming years (summarised at the end of the strategy), that will support the delivery of our 2030 ambition and the role of hydrogen in CB6 and net zero. We will design and implement these as well as any future policies following best practice guidance outlined in the HM Treasury Green Book.[96]

We will use the principles set out in Chapter 1.5 – long term value for money for taxpayers and consumers, growing the economy whilst cutting emissions, securing strategic advantages for the UK, minimising disruption and cost for consumers and households, keeping options open, adapting as the market develops and taking a holistic approach – to guide the actions we take over the coming decade. This includes the development of hydrogen-specific policies, for example the design of the Net Zero Hydrogen Fund and Hydrogen Business Model, as well as ensuring that the role of and opportunity for hydrogen is appropriately reflected in broader energy system developments, such as in delivering our goal of deploying CCUS in four industrial clusters and our aim for 40GW of offshore wind by 2030.

Our approach

Tracking our progress is essential to ensure that we are developing a UK hydrogen economy in line with the outcomes set out in Chapter 1.5 and our roadmap. As such, we will monitor progress against the outcomes while also supporting data collection on low carbon hydrogen more broadly, for example through incorporating data on its deployment into existing BEIS energy systems publications.[97] Our approach to monitoring aims to be flexible and transparent but also efficient – with a view to minimising reporting burdens on government and industry by, for example, making use of established data collection processes. This supports BEIS' vision, outlined in its monitoring and evaluation framework, to create the conditions for proportionate, good quality monitoring and evaluation across the department's policies.[98]

Flexible

As the market for low carbon hydrogen is still nascent, we will need to be flexible and adaptable in our approach to monitoring and evaluation. The success of UK offshore wind[99] shows how new low carbon technologies can defy expectations and analytical projections. The lesson is that we cannot know with certainty if the outcome measures and success indicators in this strategy will reflect the UK context in 2030. The exact mix of technologies, end use and locations which will make up the hydrogen economy is still unclear, as is how low carbon hydrogen will compare to and compete with other new low carbon technologies. We will remain alert to changes and market developments and be willing to amend our indicators and metrics if necessary.

Transparent

We want to make sure that our progress in developing a hydrogen economy is well understood, and we welcome public accountability. We are already following best practice guidance on sharing information for publicly funded hydrogen innovation projects. Sharing information and data in a transparent and open way can yield significant benefits. For example, sharing commercially appropriate insights from 'first-of-a-kind' projects will enable new project developers to better understand the conditions for success (which can make it easier to attract investment). Additionally, research conducted to date (primarily in the context of use of hydrogen for heat) has highlighted considerable public unfamiliarity with hydrogen as a technology and fuel source. The more we collect and share information, the more readily we can socialise this new decarbonisation option with the public. This strategy has signalled where there are gaps in our understanding and how we are initiating work to fill those gaps. As our understanding and delivery evolves, we will continue to keep the public informed on the progress of decarbonisation and the development of the hydrogen economy in the UK. The government will aim to publish a review of this strategy every five years, with regular updates to the market on policy development in the interim.

Efficient

This strategy details how developing a hydrogen economy cuts across a number of existing areas of economic, energy and climate policy. This means that data collected in relation to low carbon hydrogen will have multiple uses which can inform policy design and strategic prioritisation of government activity. To reflect the increasingly important role of hydrogen as a key energy vector we will incorporate data on its deployment into existing BEIS energy systems publications.[100] Similarly, we will mainstream hydrogen indicators into future monitoring frameworks, including implementation plans for the NZHF and the Hydrogen Business Model work.

Forward looking

The UK Hydrogen Strategy signals a step change in government's policy activity on hydrogen. Data collection and metrics will allow us to develop strong monitoring and evaluation processes for future policies. Evidence gathered through monitoring will develop our understanding of the hydrogen economy and will feed into the policy development cycle to ensure that future policies are evidence-based and effective.[101]

Outcomes

We will track progress against our outcomes through a set of key indicators and broader metrics where available (see Table 5 below). Given the early state of low carbon hydrogen deployment we will need to develop metrics and collect new information against many of the outcomes. Tracking a range of data will help us provide a comprehensive picture of the strategy's impact across the economy.

Table 5: Hydrogen strategy outcomes and indicative metrics

Strategy outcome	Potential indicators and metrics
Progress towards 2030 ambition	• Low carbon hydrogen capacity installed (GW) • Volume of hydrogen produced (TWh) • Breakdown by technology (such as electrolysis and methane reformation)
Decarbonisation of existing UK hydrogen economy	• Remaining volume of fossil fuel hydrogen produced (TWh)
Lower cost of hydrogen production	• Levelised cost (£/MWh)
End to end hydrogen system with diverse range of users	• Estimated volume of hydrogen used in the UK (TWh by sector)
Increased public awareness	• Percentage of people aware of/familiar with hydrogen

Promote UK economic growth and opportunities (including jobs)	• We are exploring using metrics such as:
	  • Number of low carbon hydrogen jobs available in different regions of UK and/or percentage of people trained or retrained into 'green' jobs within the sector
	  • R&D spend and patents
	  • Gross Value Added (GVA)

Emissions reduction under Carbon Budgets 4 and 5	• CO_2 emissions reduction from hydrogen
Evidence-based policy making	• Quantitative and qualitative data collected • Engagement with stakeholders and expert advice

We will develop clear metrics in line with Table 5 above to enable us to monitor progress against our outcomes and commitments in this strategy, including incorporating data on hydrogen production into the Digest of UK Energy Statistics (DUKES).

We recognise that industry, investors and other stakeholders will value and need further clarity on what government is doing to support the hydrogen economy as it develops and scales up over the course of the decade and beyond. As indicated in Chapter 1.5, we intend to provide regular updates to the market as our policy develops. The first of these is expected in early 2022, where we intend to provide a response to our Hydrogen Business Model consultation and indicative heads of terms, our hydrogen production strategy and finalised design elements of the low carbon hydrogen standard. This approach will support learning by doing and maintain ongoing dialogue and engagement, providing early certainty and clarity where possible while developing the sustainable, long term underpinnings of a dynamic, world-leading hydrogen economy and securing strategic advantages for the UK.

Delivering a thriving UK hydrogen economy

Low carbon hydrogen has a key role to play in the UK's net zero energy future. The 2020s will be critical for laying the groundwork to develop a thriving hydrogen economy by 2030, positioned for further ramp up to help meet CB6 and set us on a pathway to net zero by 2050. This strategy sets out our whole-system approach to meeting this ambition. This includes working closely with industry and the research and innovation community to scale up along the value chain and put in place the wider policy frameworks to support this, and to secure the economic opportunities that the hydrogen economy holds for the whole of the UK. In doing so, we will work with our international partners to ensure that low carbon hydrogen can contribute to the global transition to net zero, and we will track our progress to make sure that we deliver on our objectives. Building a thriving UK hydrogen economy is a once-in-a-lifetime opportunity to help create a new, clean energy industry of the future which can play a key role in the UK's transition to net zero and deliver real economic opportunities across the UK.

Full list of commitments

Chapter	Commitment
2.2 Production	We will work with industry to deliver our ambition for 5GW of low carbon hydrogen production capacity by 2030. In doing so, we would hope to see 1GW of production capacity by 2025.
	We will provide £240m for the Net Zero Hydrogen Fund out to 2024/25 for co-investment in early hydrogen production projects. We intend to launch this Fund in early 2022.
	We will provide up to £60 million under the Low Carbon Hydrogen Supply 2 competition, which will develop novel hydrogen supply solutions for a growing hydrogen economy.
	We intend to finalise the design elements of a UK standard for low carbon hydrogen by early 2022.
	We intend to provide a response to our consultation on a Hydrogen Business Model alongside indicative Heads of Terms in Q1 2022. We aim to finalise the business model in 2022, enabling the first contracts to be allocated from Q1 2023.
	We will develop further detail on our production strategy and twin track approach, including less developed production methods, by early 2022.
2.3 Networks & storage	We will continue to support research, development and testing projects to explore development of hydrogen network infrastructure.
	We will review the overarching market framework set out in the Gas Act 1986 to ensure appropriate powers and responsibilities are in place to facilitate a decarbonised gas future.
	We are reviewing gas quality standards with a view to enabling the existing gas network to have access to a wider range of gases in future, potentially including hydrogen.
	We will launch a Call for Evidence on the future of the gas system this year.
	We will undertake a review of systemic hydrogen network requirements in the 2020s and beyond, including need for economic regulation and funding. We will provide information on the status and outputs of this hydrogen network review in early 2022.
	We will provide up to £68 million for the Longer Duration Energy Storage Demonstration competition, with storing hydrogen produced from excess electricity in scope (subject to eligibility criteria).
	We will undertake a review of systemic hydrogen storage requirements in the 2020s and beyond, including need for economic regulation and funding. We will provide information on the status and outputs of this review in early 2022.
	We will use the Hydrogen Business Model consultation to seek views on a number of questions which will feed into our hydrogen network and storage reviews.
	We will provide up to £60 million under the Low Carbon Hydrogen Supply 2 competition, which will develop novel hydrogen supply solutions, including storage technologies.

Chapter	Commitment
2.4.1 End use: industry	Within a year, we will publish a Call for Evidence to explore with industry the further interventions needed to phase out carbon intensive hydrogen and transition to low carbon production methods and sources, at the required pace to meet net zero.
	We will provide grant funding to support fuel switching technologies, including low carbon hydrogen, through Phase 2 of the £315m Industrial Energy Transformation Fund.
	We will launch a new £55 million Industrial Fuel Switching 2 Competition later this year to develop and demonstrate innovative solutions for industry to switch to low carbon fuels such as hydrogen.
	We will launch a new £40 million Red Diesel Replacement Competition to fund the development and demonstration of innovative technologies that enable Non-Road Mobile Machinery (NRMM) used for quarrying, mining, and construction to switch from red diesel to hydrogen or other low carbon fuels.
	We will provide support for research and innovation to support use of hydrogen in industry through the Net Zero Innovation Portfolio and initiatives led by the Industrial Decarbonisation Research & Innovation Centre.
	We will work with cluster projects to better understand the opportunities that pathfinder sites present, so to maximise the benefit to the sites themselves and the associated clusters.
	By the end of this year we will launch a new Call for Evidence on 'hydrogen-ready' industrial equipment.
	We will work with industrial end users to ensure their needs and the potential impacts of a full or partial transition to hydrogen via the gas grid are well understood.
2.4.1&2 End use: industry & power	We will engage with industry later this year on possible requirements for a research and innovation facility to support hydrogen use in industry and power.
2.4.2 End use: power	We will engage with industry to understand the economics and system impacts of introducing hydrogen into the power sector, including the impacts of sector coupling and utilising hydrogen energy storage.
	We will review the progress of recent actions in the power sector, and engage with relevant stakeholders and hydrogen projects early to ensure there is suitable support for hydrogen in the power sector.
2.4.3 End use: heat in buildings	We will deliver hydrogen for heat trials (neighbourhood by 2023, village by 2025 and potential pilot town by 2030), with a view to inform our 2026 strategic decision point on the future of hydrogen for heat.
	We aim to consult later this year on the case for enabling, or requiring, new natural gas boilers to be easily convertible to use hydrogen ('hydrogen-ready') by 2026.

Chapter	Commitment
2.4.4 End use: transport	We will provide up to £120 million this year through the Zero Emission Bus Regional Areas (ZEBRA) scheme towards 4,000 new zero emission buses, either hydrogen or battery electric, and infrastructure needed to support them.
	We will provide up to £20 million this year to design trials for both electric road system and hydrogen long haul heavy road vehicles (HGVs) and to run a battery electric trial to establish the feasibility, deliverability, costs and benefits of each technology.
	We will provide up to £20 million this year for the Clean Maritime Demonstration Competition, to accelerate the design and development of zero emission marine vessels in the UK.
	We will provide up to £15 million this year for the 'Green Fuels, Green Skies' competition to support the production of first-of-a-kind sustainable aviation fuel plants in the UK.
	We will provide £3 million this year to support the development of a Hydrogen Transport Hub in Tees Valley, and £4.8 million (subject to business case) to support the development of a hydrogen hub in Holyhead, Wales.
2.5.1 Creating a market: market framework	We intend to provide a response to our consultation on a Hydrogen Business Model alongside indicative Heads of Terms in Q1 2022. We aim to finalise the business model in 2022, enabling the first contracts to be allocated from Q1 2023. We will provide further detail on the revenue mechanism which will provide funding for the Business Model later this year.
	We will undertake further work to understand and develop appropriate market frameworks to drive investment and deployment and transition to longer term competitive market frameworks. We will aim to publish initial conclusions and proposals in early 2022.
	We will work across government to highlight the potential role of hydrogen in the future energy system and consider how this should be reflected in the design of wider energy markets and policies (e.g. capacity market, green gas support scheme).
	We will continue to work with industry and regulators in the early 2020s to identify, prioritise and address regulatory barriers faced by hydrogen projects, and consider changes needed to unlock hydrogen investment and deployment across the value chain. We will aim to publish initial conclusions and proposals in early 2022.
Case study: gas blending	We will engage with industry and regulators to develop the safety case, technical and cost effectiveness assessments of blending up to 20 per cent hydrogen (by volume) into the existing gas network. Subject to completion of safety trials, we aim to provide an indicative assessment of the value for money case for blending by Q3 2022, with a final policy decision likely to take place in late 2023.

Chapter	Commitment
2.5.2 Creating a market: regulatory framework	We will continue to work with industry and regulators to consider what regulatory changes may be appropriate across the hydrogen value chain.
	We will work across government to highlight the potential role of hydrogen in the future energy system and consider whether and how this should be reflected in wider regulatory and policy changes.
	We will establish a Hydrogen Regulators Forum, with representation across the relevant regulatory areas (environmental, safety, markets, competition and planning).
	We will work across government and with regulators to ensure that interlinkages between hydrogen and broader governance and regulatory changes are appropriately considered. We will consult this year on the institutional arrangements governing the energy system over the long term, including system operation and energy code governance.
3.1 Economic benefits: supply chains	We will actively monitor the extent to which competitive UK businesses are benefitting as the hydrogen sector matures. If necessary, we will consider what options are open to ensure a fair playing field that includes UK businesses. We will set out more detail on this in our Hydrogen Sector Development Action Plan by early 2022.
	We will work with industry to improve visibility of the low-carbon hydrogen project pipeline across the supply chain, learning from the successes of initiatives in other low-carbon sectors.
3.2 Economic benefits: jobs and skills	As part of our work to develop the low carbon hydrogen sector, we will assess the opportunities for hydrogen employment across the UK.
	We will work with industry, trades unions, the devolved administrations, local authorities, and enterprise agencies to support sustained and quality jobs and ensure that there is effective and targeted investment in relevant skills.
	We will work with industry, education providers and local and regional authorities to explore opportunities for relevant skills programmes, including apprenticeships and re-skilling programmes.
	We will set up an Early Career Professionals Forum under the Hydrogen Advisory Council.
	We will continue to monitor skills as the hydrogen sector matures and consult if necessary to identify barriers to sufficient private sector investment into growing the UK skills base and supporting good quality jobs and equality of opportunity.

Chapter	Commitment
3.3 Economic benefits: maximising UK R&I strengths	We will support hydrogen innovation as one of the ten key priority areas in the £1bn Net Zero Innovation Portfolio.
	We will work with the Hydrogen Advisory Council and other partners to better understand the scale, scope and type of private sector investment into hydrogen R&I in the UK, and how it can be further incentivised.
	We will work with experts including the newly established R&I Working Group under the Hydrogen Advisory Council to develop a hydrogen technology R&I Roadmap to inform public and private sector R&I investment and prioritisation.
	We will use our role as one of the co-leads of Mission Innovation's new Clean Hydrogen Mission to champion open and active international engagement and research sharing to accelerate hydrogen R&I progress and maximise its benefits.
	We will continue to foster collaborative international research and information exchange through our active membership of the International Energy Agency (IEA) Hydrogen Technology Collaboration Programme (Hydrogen TCP).
4 International: demonstrating global leadership	Through the G7, including our Presidency this year, we will reaffirm the importance of low carbon hydrogen in the clean energy transition, and seek commitments to increase its production and deployment.
	Through our global climate leadership, including through our co-Presidency of COP26, we will seek to bring together public and private actors who recognise the crucial role that hydrogen can play in tackling emissions and unleashing clean growth to facilitate greater coordination and progress across international hydrogen innovation, deployment and policy activity.
5 Tracking our progress	We will develop metrics to enable us to monitor progress against our outcomes and the commitments in this strategy, including incorporating data on hydrogen production into the Digest of UK Energy Statistics.

Endnotes

1 Internal BEIS analysis based on the Energy Innovation Needs Assessment (EINA) methodology with updated domestic and global scenarios; figures consider the direct GVA and jobs linked to hydrogen production, stationary CHP fuel cells and domestic distribution only; EINA methodology provided by Vivid Economics (2019), 'Hydrogen and fuel cells (EINA sub-theme)' (viewed 1 June 2021)
2 Data from the Fuel Cells and Hydrogen Observatory suggests less than one per cent of hydrogen production capacity in the UK is from electrolysis, the carbon intensity of which depends on the electricity source; see Fuel Cells and Hydrogen Observatory (2021), 'Hydrogen Supply Capacity' (viewed 9 June 2021)
3 Fuel Cells and Hydrogen Observatory (2021), 'Hydrogen Demand' (viewed 9 June 2021)
4 Department for Business, Energy and Industrial Strategy (2021), 'Carbon Budget 6 Impact Assessment' (viewed 9 June 2021)
5 Hydrogen as a proportion of final energy consumption in 2050 in agriculture, industry, residential, services and transport sectors; excludes energy demand for resources, processing and electricity generation
6 Department for Business, Energy and Industrial Strategy (2021), 'Final UK greenhouse gas emissions national statistics' (viewed 9 June 2021)
7 HM Government (2020), 'The Ten Point Plan for a Green Industrial Revolution' (viewed 22 June 2021)
8 Based on estimates of carbon captured by trees over 10 year period; see Forestry Commission (2020), 'Responding to the Climate Emergency with New Trees and Woodlands' (viewed 16 June 2021); Forestry Commission (2019), 'Government Supported New Planting of Trees in England' (viewed 16 June 2021)
9 Internal BEIS analysis based on EINA methodology with updated domestic and global scenarios (see Figure 1)
10 HM Government (2020), 'The Ten Point Plan for a green industrial revolution' (viewed 1 June 2021)
11 Internal BEIS analysis based on EINA methodology with updated domestic and global scenarios (see Figure 1)
12 Scottish Government (2020), 'Scottish Hydrogen Assessment' (viewed on 21 June 2021)
13 Scottish Government (2020), 'Scottish Government Hydrogen Policy Statement' (viewed 21 June 2021)
14 UK Government (2021), 'Heads of Terms for the Islands Growth Deal' (viewed 21 June 2021)
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APPENDIX 5 UK HYDROGEN SAFETY LAW: THE DEVELOPING FRAMEWORK

Pinsent Masons

OUT-LAW GUIDE 9 min. read

UK hydrogen safety law: the developing framework

28 Feb 2023, 4:31 pm

As the UK's fledgling low carbon hydrogen industry develops, a combination of existing health and safety laws and additional, hydrogen-specific standards and guidance seems like the most likely route to effective safety regulation.

As the world looks to decarbonise there has been increased attention on the development and use of low carbon hydrogen. However, as investment and projects are brought forward, policymakers are conscious that there is a need to overcome the negative public perception of hydrogen as not being 'safe'. This seems to be based on media reporting and striking images of high profile safety incidents often from decades ago.

To ensure that safety issues are not seen as some sort of handbrake on energy diversification a case needs to be made that this perception does not match up with the reality, with many industries already safely managing high-risk substances, keeping workers safe and maintaining the confidence of both the public and investors.

The inherent natural properties of hydrogen do make it a substance which requires particular safety management. These include:

- a hydrogen flame is hard to see in daylight and doesn't emit a large amount of heat, meaning it is hard to detect without flame detection colourant;
- hydrogen lacks smell, again making it hard to detect without added odorant;
- hydrogen is buoyant and therefore rises rapidly, which may lead to explosive mixtures quickly forming;
- hydrogen is easier to transport in cryogenic liquid form rather than gas due to its large volume – this requires specialist training for all handlers;

- mixtures of air and hydrogen forming accidentally within contained systems must be avoided due to their high volatility – this impacts on maintenance which will need to be well planned rather than reactive;
- hydrogen corrodes certain materials – for example, steel – more quickly than its natural gas counterpart, meaning that careful consideration must be given to the materials used in storage and transportation of hydrogen.

This of itself does not mean that hydrogen is any more or less safe than natural gas or petroleum-based products. However, it does mean that hydrogen-specific consideration must be given to storage, transportation and utilisation with specific controls in place to prevent corrosion, gas escapes and ignition. As the use of low carbon hydrogen increases, understanding the safety issues and implementing these controls becomes ever more important.

Why the need for low carbon hydrogen?

The increasing cost of fossil fuels and natural gas has led to soaring prices in European energy markets, and highlighted the urgent need to move towards more sustainable fuels.

At the same time, the cost of energy crisis has highlighted the absence of clear and available alternatives to hydrocarbons in many parts of the energy system, even as the European Commission and many national governments – including the UK – set net zero emissions targets.

Laura White
Senior Associate

There is no hydrogen specific safety legislation in the pipeline. It seems clear the UK hydrogen market will get underway utilising current legislation, along with hydrogen specific standards and guidance

To meet these targets and reduce emissions there needs to be low-carbon fuel alternatives, and UK and European policymakers have set their sights on low-carbon hydrogen as one of them.

Although hydrogen today is mostly made via carbon-intensive steam methane reforming methods, its emissions can be curtailed by adding carbon capture and storage (CCS) to the process, or by making the gas from water through electrolysis.

The UK Government Hydrogen Strategy states that low carbon hydrogen is fundamentally necessary to net zero. However, entirely new infrastructure systems are required to make this a reality. There are existing safety regulatory frameworks for electricity and gas which are applicable for hydrogen but for hydrogen production, use and transport at scale may need to be enhanced over time.

Creating infrastructure for the transport and storage of hydrogen is crucial, along with repurposing existing infrastructure.

The UK government's energy security strategy, published in April 2022, sets out how Great Britain will accelerate the deployment of wind, new nuclear, solar and hydrogen, while supporting the production of domestic oil and gas in the nearer term – which could see 95% of electricity by 2030 being low carbon.

The UK is looking to set up a hydrogen certification scheme by 2025, to demonstrate high-grade British hydrogen for export and ensure any imported hydrogen meets the same high standards that UK companies expect.

What health and safety laws currently apply to UK hydrogen activities?

The UK gas network is commercially regulated by the Gas and Electricity Markets Authority, operating through Ofgem. Hydrogen falls in the definition of 'gas' under the Gas Act 1986 and is therefore regulated as part of the gas network, and anyone engaging in any hydrogen operations must have a licence under the Gas Act. There is also an established legislative regime and framework governing gas and pipelines, which apply to hydrogen.

A number of pieces of safety legislation apply to hydrogen:

- the Planning (Hazardous Substances) Act 1990 and Planning (Hazardous Substances) Regulations 2015 regulate the storage of hydrogen, including a requirement for consent where two or more tonnes of hydrogen are to be stored.
- the Dangerous Substances and Explosive Atmosphere Regulations (DSEAR) 2002 place duties on employers to eliminate or control the risks from explosive atmospheres in the workplace, and require employers to eliminate or control the risks from dangerous substances. DSEAR also gives effect to the two EU directives for controlling explosive atmospheres, together known as ATEX.
- the Pipeline Safety Regulations 1996 set out requirements for pipeline design, construction, installation, operation, maintenance, and decommissioning, while the Notification of Installations Handling Hazardous Substances Regulations 2002 places restrictions on handling hazardous substances in quantities exceeding a threshold.
- the Gas Safety (Management) Regulations (GSMR) 1996 require any transporters of gas, including hydrogen, to submit a safety case to the Health & Safety Executive (HSE) identifying hazards and risks and how they are controlled.
- the Control of Major Accident Hazards Regulations 2015 also regulate the storage of hydrogen. It requires operators to take all measures necessary to prevent major accidents and to limit consequences for human health and the environment.
- the Carriage of Dangerous Goods and Use of Transportable Pressure Equipment Regulations 2004 apply to the carriage of dangerous goods, including hydrogen, by road and rail and places general duties on everyone with a role in transporting the goods.
- the Alternative Fuels Infrastructure Regulations 2017 SI 2017/825 apply to the provision of certain alternative fuel infrastructure. The infrastructure relates to electricity and hydrogen for vehicles and seagoing ships at berth.

The Health and Safety at Work etc. Act 1974, Construction (Design and Management) Regulations 2015, and Building Regulations 2010 are also likely to apply in certain instances.

What possible approaches are there for further regulating hydrogen in the UK?

Bearing in mind there is no hydrogen specific safety legislation in the pipeline it seems clear the UK hydrogen market will get underway utilising current legislation, along with hydrogen specific standards and guidance.

Notably, the GSMR only currently permits 0.1% hydrogen to be introduced to the existing gas network. For greater amounts this needs to be permitted by way of direct exemption from the HSE – something which is currently being trialled.

Exemptions are allowed for increased use of hydrogen only where it can be shown that the health and safety of any person likely to be affected by the exemption will not be prejudiced in any way.

What does the hydrogen health and safety regulation picture look like internationally?

Internationally a wide range of hydrogen safety programmes are well established and developing swiftly.

In Europe, the European Hydrogen Safety Panel (EHSP) was launched in 2017 to support the EU's Fuel Cells and Hydrogen Joint Undertaking in projects and programmes. The EHSP focuses on promoting safety in the production, storage, distribution and use of hydrogen, recognising that any failure would have a serious impact on the public's perception of hydrogen and fuel cell technologies.

The EHSP's general protection objective is to exclude or at least minimise potential hazards and associated risks to prevent impacts on people, property and the environment.

In the US, the Department of Energy's Hydrogen Program seeks to ensure the safe operations of hydrogen research and development, and identify and address needs for new knowledge and technology in the future hydrogen economy.

The programme has developed a free best practices and training resource for emergency responders dealing with hydrogen-related incidents, as well as providing up-to-date, credible information relating to hydrogen safety.

In Australia, Standards Australia is instrumental in development and adoption of hydrogen standards which includes safety aspects, working closely with key stakeholders to move Australia towards a more sustainable future. It adopted eight key hydrogen standards in 2020, and work to bring further guidance to the sector is ongoing. These include safety considerations – for example safety aspects of hydrogen generators; the construction, safety and performance of systems to produce hydrogen by the electrolysis of water; and design and safety features of systems to purify hydrogen to meet quality standards.

What is the experience of using hydrogen so far?

One thing which is essential for hydrogen safety is international collaboration on safety methods, including materials usage and communicating outcomes of serious incident investigation. Several investigations undertaken after hydrogen safety incidents have been published online, and these are invaluable in aiding understanding of the particular features to be aware of in hydrogen safety and primary incident causes from past events.

A significant hydrogen safety event took place in the US in the summer of 2019 during a gaseous hydrogen fill of a modular multi-cylinder trailer. Hydrogen was accidentally released from an open pipe following an unauthorised attempt to repair a leaking valve and a subsequent miscommunication between the two drivers filling the trailer. A hydrogen-air mixture explosion occurred within seconds of the release, followed by a high-pressure gas jet fire. The fire and explosion caused pipe damage and activation of hydrogen cylinder temperature-pressure relief devices, adding additional hydrogen fuel to the incident, and eventually spreading to other materials on adjacent vehicles.

Two individuals sustained minor injuries during the incident, and there was significant property damage on-site. Personnel initiated a shutdown and isolation of other trailers and tanks to prevent further releases.

The reported primary causes of the incident were:

- unauthorised maintenance performed by personnel not following proper procedures; and
- miscommunication between the two drivers filling the trailer.

The improvement measures implemented by the affected business ring true for many health and safety related incidents outside of innovative energy markets; the improved training of the drivers, filing procedures, and evaluated and modified some equipment for better use with hydrogen. So while the nature of hydrogen caused this incident unexpectedly, the safety steps which need to be taken are very familiar to those already working with hazardous substances and in high risk industries.

Other research shows that the main causal factors in hydrogen incidents are lack of training and a poor understanding of hydrogen hazards. Clearly the nature of hydrogen means that the impact of such incidents has high potential but the control methodologies available allow the frequency of them to be greatly reduced. With an increase in hydrogen production and usage anticipated, hydrogen specific training will also need to be increased proportionately. For example for maintenance or emergency response.

Just under two thirds of incidents are in the chemical and petrochemical sectors, which reflects current hydrogen usage. Clearly the broader range of sectors hydrogen is utilised in the increased risk of hydrogen incidents to those sectors.

What is being done to assess hydrogen safety in practice?

In Scotland, chemicals company INEOS and Scottish Gas Networks have started a 29km pipeline project to show how natural gas pipelines can be repurposed to distribute hydrogen.

At Keele University, a £7 million zero carbon hydrogen injection gas network to heat homes is now fully operational. The 20% blend feed will heat 100 homes and 30 faculty buildings.

At Winlanton, near Gateshead in the north of England, a Cadent/Northern Gas Networks partnership is delivering a 20% hydrogen blend to 670 homes for cooking and heating. The last two projects are also in partnership with the HSE.

Other areas the HSE are working on are:

- ensuring the safety of hydrogen vehicles in tunnels and confined spaces
- helping the Port of London develop a national hydrogen highway network
- researching into the safe use of liquid hydrogen

In addition the HSE are hosting the first Safe Net Zero at the QEII Centre in London from 21-22 March 2023, bringing together a wide range of organisations who are developing and deploying hydrogen technologies

CONTACT AN ADVISER

Jon Cowlan

Health & Safety Manager

[redacted]

[redacted]@pinsentmasons.com

Laura White

Senior Associate

[redacted]

[redacted]@pinsentmasons.com

Pinsent Masons

APPENDIX 6 BCGA CODE OF PRACTICE CP 33

BCGA CODE OF PRACTICE CP 33

The Bulk Storage of Gaseous Hydrogen

at Users' Premises

Revision 1: 2012

British Compressed Gases Association

BCGA CODE OF PRACTICE CP 33

The Bulk Storage of Gaseous Hydrogen

at Users' Premises

Revision 1: 2012

BRITISH COMPRESSED GASES ASSOCIATION

4a Mallard Way
Pride Park
Derby
DE24 8GX

Website: www.bcga.co.uk

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PREFACE

The British Compressed Gases Association (BCGA) was established in 1971, formed out of the British Acetylene Association, which existed since 1901. BCGA members include gas producers, suppliers of gas handling equipment and users operating in the compressed gas field.

The main objectives of the Association are to further technology, to enhance safe practice, and to prioritise environmental protection in the supply and use of industrial gases, and we produce a host of publications to this end. BCGA also provides advice and makes representations on behalf of its Members to regulatory bodies, including the UK Government.

Policy is determined by a Council elected from Member Companies, with detailed technical studies being undertaken by a Technical Committee and its specialist Sub-Committees appointed for this purpose.

BCGA makes strenuous efforts to ensure the accuracy and current relevance of its publications, which are intended for use by technically competent persons. However this does not remove the need for technical and managerial judgement in practical situations. Nor do they confer any immunity or exemption from relevant legal requirements, including by-laws.

For the assistance of users, references are given, either in the text or Appendices, to publications such as British, European and International Standards and Codes of Practice, and current legislation that may be applicable but no representation or warranty can be given that these references are complete or current.

BCGA publications are reviewed, and revised if necessary, at five-yearly intervals, or sooner where the need is recognised. Readers are advised to check the Association's website to ensure that the copy in their possession is the current version.

This document has been prepared by BCGA Technical Sub-Committee 1. This document replaces BCGA CP 33: 2005. It was approved for publication at BCGA Technical Committee 143. This document was first published on 29/06/2012. For comments on this document contact the Association via the website www.bcga.co.uk.

CONTENTS

* Throughout this document numbers in brackets refer to references in Section 7. Documents referenced are the edition current at the time of publication of this Code of Practice.

TERMINOLOGY AND DEFINITIONS

Shall	A mandatory requirement for compliance with this Code of Practice.
Should	A preferred requirement but this is not mandatory for compliance with the Code of Practice.
May	An option available to the user of this Code of Practice.
Hydrogen storage	A gaseous hydrogen storage system is one in which the contents have sufficient hydrogen to be flammable when mixed with air and are stored or discharged in a gaseous form. The system includes containers, pressure regulators, instruments, safety-relief devices, manifolds, inter-connecting piping and controls. The storage system terminates at the point where hydrogen, at nominal service pressure, enters the distribution piping.
Bulk storage	For the purposes of this document bulk storage is defined as hydrogen storage which consists of fixed cylinders manifolded together, or tubes which may be either fixed in place or mounted on a transportable trailer, or one or more medium pressure vessels.
Cylinder	Transportable pressure receptacle of up to 150 litres water capacity.
Tube	Seamless transportable pressure receptacle of between 150 and 3000 litres water capacity.
Medium pressure vessel	A hydrogen storage vessel designed for fixed installation only and working at up to 100 bar operating pressure.
Bundle	A cylinder bundle, or manifolded cylinder pallet, consists of a number of cylinders permanently manifolded to a common outlet and contained in a rigid, protective framework for ease of handling by forklift truck or crane.

BCGA CODE OF PRACTICE CP 33

The Bulk Storage of Gaseous Hydrogen at Users' Premises

1 SCOPE

This Code of Practice covers the location, design, installation, commissioning, operation and maintenance of equipment for the bulk storage and supply of compressed hydrogen gas at users' premises.

This includes:

a) The issues surrounding safety distances around hydrogen installations, including security, electrical classification, vehicle access, fire fighting, planning and notification of relevant authorities.

b) Criteria for the design of the storage vessels, pressure and flow control equipment.

c) Safety issues associated with the installation and commissioning of the equipment.

d) Guidance on safe operation of the installation, both for the user and the gas supplier.

e) Maintenance, including both preventive and routine, covering specific requirements of UK legislation. This includes frequency and method for in-service inspection.

f) Fixed systems refilled on site consisting of transportable pressure receptacles (including cylinders, tubes or bundles) or medium pressure vessels.

Reference is made to relevant legislation, Codes of Practice and Standards, which are listed in Section 7. The hazards and properties of compressed hydrogen are summarised in Appendix 1.

Compliance with the Pressure Equipment Regulations (PER) (4), The Equipment and Protective Systems Intended for Use in Potentially Explosive Atmospheres Regulations (1), The Dangerous Substances and Explosive Atmospheres Regulations (7) and the Pressure Systems Safety Regulations (PSSR) (6) is mandatory. The materials and pressurised equipment used for the installations will need to comply with the essential safety requirements specified in the Regulations.

Compliance with the Management of Health & Safety at Work Regulations (5) will require risk assessments to be carried out, which may include a formal HAZOP, during the process of installation of bulk hydrogen systems.

This code does not include:

g) Liquid hydrogen. A summary of the requirements for safe operation with liquid hydrogen is given in the European Industrial Gases Association (EIGA) document 6/02 (14) or the USA National Fire Protection Association document 55 (18).

h) Systems consisting only of transportable pressure receptacles that are not fixed storage. For these systems see BCGA Code of Practice CP 4 (16).

2. LOCATION OF HYDROGEN INSTALLATION

The installation should whenever practicable be located outside in the open air. Other locations may be considered after a suitable and sufficient risk assessment has been completed. Detailed guidance on considerations for location inside buildings is given in Appendix 3.

Hydrogen installations shall not be placed in pits where there is any restriction of the means of escape in an emergency.

The installation shall be located so that it is readily accessible to delivery vehicles, to authorised personnel and to emergency services. However, it shall be protected against physical damage and access by unauthorised personnel. Fencing shall be provided unless there is adequate control to prevent access by unauthorised persons.

On controlled sites with sufficient supervision fencing is optional.

Where fencing is provided the minimum clearance between the fence and the installation shall be 0.6 m to allow free access to and escape from the enclosure.

The safety distances given in Table 1 will apply regardless of the position of the fence.

Timber or other readily combustible materials should not be used for fencing. The height of the fencing should be at least 1.8 m.

Any gates should be outward opening and wide enough to provide for an easy access and exit of personnel.

a) The main gate should have two wings, each at least 0.6 m wide.

b) The emergency exit gate should have one wing, at least 0.8 m wide.

Gates shall be locked during normal operation. Consideration should be given to the provision of an additional emergency exit where the size of fenced area or equipment location necessitates this.

All the control equipment for the safe operation of the installation shall be easily accessible to the plant operations personnel and delivery driver and all instrumentation shall be clearly visible.

A site specific risk assessment shall be conducted to establish the acceptability of near by electrical equipment or other sources of ignition.

Minimum separation distances of the installation from various hazards are given in Table 1.

NOTE: Table 1 does not apply to a delivery vehicle when the driver is present throughout the delivery process.

Trailers which form part of the fixed installation shall comply with the safety distances.

Approval may be required for the installation from the local planning authority, the fire authorities and the Health & Safety Executive. These requirements should be resolved with the owners of the premises where the installation is planned.

3 DESIGN OF INSTALLATION

3.1 General

The design and installation shall comply with The Equipment and Protective Systems Intended for Use in Potentially Explosive Atmospheres Regulations (1), The Dangerous Substances and Explosive Atmospheres Regulations (7), The Pressure Systems Safety Regulations (6) and The Pressure Equipment Regulations (4).

3.1.1 The installation consists usually of fixed storage, which may be provided either by a number of high pressure cylinders, tubes or bundles manifolded together or by medium pressure vessel(s), together with a pressure control station feeding the customer pipeline. The refilling of the fixed storage is usually achieved by cascade from a transport trailer, with control of the cascade process also carried out via the pressure control station. An alternative is for the storage to be refilled by local hydrogen generation and compression. In certain circumstances the fixed storage is replaced by the use of multiple trailers. In all cases, the pressure-reducing and control equipment shall be as close as practicable to the storage.

3.1.2 The installation shall be designed with a proper allowance for the manoeuvring of the transport trailer and shall have adequate lighting.

3.1.3 The foundations of the fixed storage shall be designed to allow for the loading imposed by the cylinders or medium pressure vessel(s). If cylinders are used as the fixed storage they should be supported in a manner to prevent corrosion resulting from standing in water, for example on metal gratings or suitable supports.

3.1.4 In the case of multiple trailer installations, the trailers should be sited to achieve adequate separation. This will mean at least 3.5 m between centres.

3.1.5 To prevent damage to equipment from the trailer, it is required, where such a risk exists, to provide a "bump-stop" to alert the driver when the trailer is in position, with at least 1 m clearance from the hazard.

3.1.6 Where two or more medium pressure vessels are required in an installation the vessels shall be separated by at least 1 m at their closest point. This does not apply to bundles.

3.1.7 An area classification drawing shall be prepared, indicating the requirements for the use of appropriately classified electrical equipment, as required under The Dangerous Substances and Explosive Atmospheres Regulations (7). All electrical equipment shall then comply with these requirements. BS EN 60079 (12) provides information.

3.1.8 A fire risk assessment shall be carried out. The assessment shall identify fire-fighting requirements such as the volume and pressure of available water. An emergency procedure shall also be drawn up following completion of the risk assessment.

3.1.9 Adequate means of escape in case of emergency shall be provided. In cases where personnel could be trapped inside compounds there shall be not less than two separate outward opening exits remote from each other and strategically placed with respect to the source of the hazard.

3.1.10 Notices shall be positioned so that they are visible from all sides of approach to the installation. They should read:

HYDROGEN – FLAMMABLE GAS

NO SMOKING – NO NAKED FLAMES

These notices shall include "pictorial" symbols in accordance with the Health and Safety (Safety Signs & Signals) Regulations (2). Compliance with these Regulations is mandatory. These signs shall be supplemented by a flammable material warning triangle. Examples are shown in Figure 1.

Figure 1. Examples of pictorial symbols.

3.1.11 The area within 3 m of any hydrogen installation shall be kept free of weeds and vegetation. If weed killers are used, chemicals such as sodium chlorate, which is a potential source of fire danger, should not be used.

3.1.12 Adequate means of giving alarm in the event of a fire shall be provided. These should be clearly marked and suitably located at all emergency exit points.

3.1.13 When the hydrogen is supplied from a tube trailer, a suitable and sufficientanti-tow-away system must be provided.

3.2 Cylinders, tubes and medium pressure vessels.

Details of design requirement of cylinders, tubes and medium-pressure vessels are not included in this document. Attention is drawn to the EIGA document 15/06 (15) for information on medium-pressure vessel design requirements. Appendix 5 of that document specifies, in Clause A.2.1.1, a maximum yield-strength of 420 MPa. Compliance with this BCGA Code of Practice requires the adoption of 360 MPa for this type of vessel and the use of post weld stress relief by heat treatment.

3.3 Piping

3.3.1 Piping and fittings shall be suitable for hydrogen service at the pressure and temperature involved. Cast iron pipe and fittings shall not be used. The design shall be to an appropriate, recognised design code.

3.3.2 Permanent joints (i.e. welded or brazed) are recommended. Flanged or screwed joints are acceptable but their use should be minimised. Compression fittings are generally not recommended, except where essential for small bore instrument lines, when the manufacturer's instructions for assembly shall be strictly observed.

3.3.3 Vents shall be provided to enable the system to be depressurised in a safe manner, for purging and at high and low points for testing.

3.3.4 All vents, including those of pressure relief devices, shall be designed or located so that moisture cannot collect and freeze in a manner which could interfere with the proper operation of the device.

3.3.5 Vents, including those of pressure relief devices, shall be arranged to discharge in a safe place, into the open air. Normally this will be above head height so as to prevent impingement of escaping gas upon any personnel and structure. Pressure relief vents shall be piped individually without manifolding, though manual vents may be manifolded where design permits. They shall not discharge where gas could accumulate, such as below the eaves of buildings. It should be noted that hydrogen can easily ignite; vents should, therefore, be orientated to avoid any flame impinging on vulnerable equipment, or the effects of radiated heat.

3.3.6 Cabinets or housings containing hydrogen control or operating equipment shall be adequately ventilated, particularly at high level, to prevent accumulation of hydrogen in the event of leakage. They shall be positioned so that, in the event of a leak, the gas can disperse in a safe manner and the effects of any resultant fire can be minimised. If the necessary ventilation is provided by mechanical systems then the ventilation air shall be drawn from a safe place and an appropriate detection / alarm system should be installed to detect the failure of the ventilation system or the presence of hydrogen well before a flammable concentration is reached.

3.3.7 Relief valves shall be sized to allow for the worst foreseeable case, i.e. regulator failure combined with full storage developed pressure at 60 °C.

3.3.8 Pipes should be installed above ground whenever practicable. Where lines must be buried they shall be below the frost level. If pipes must be run under roads or railways they shall be placed in pipe sleeves, which are vented above ground to a minimum height of 3 m in a safe place. The distribution pipework shall be in accordance with BCGA Code of Practice CP 4 (16).

3.3.9 Isolation valves shall be provided so that the hydrogen source can be shut off safely in the event of an emergency. This is particularly important where hydrogen lines enter buildings.

3.3.10 The entire system must be continuously electrically earthed with a maximum resistance to earth of 10 Ω or in accordance with national standards whichever is the most stringent. The earthing connections should be in position prior to a flammable mixture being present and also during filling with, or emptying of, a flammable fluid. This shall include effective earthing of the delivery vehicle. The earth rod for static earthing must be solidly connected to earthing rods for electrical supplies or lightning discharges. For lightning protection the installation should comply with BS EN 62305 (13).

3.3.11 Pressure gauges. If bourdon tube type gauges are used the tube must be specified to be either beryllium copper or phosphor bronze.

3.4 Testing

3.4.1 After installation all piping and fittings shall be, where practicable, hydraulically and pneumatically tested. The system shall be thoroughly dried out after these tests. Where it is not practicable to carry out a hydraulic test prior to the pneumatic test, appropriate precautions shall be taken as described in HSE Guidance Note GS-4 (10). The system shall be helium leak tested or other suitable leak detection methods adopted prior to the introduction of hydrogen.

3.4.2 A final function test with hydrogen at maximum operating pressure should be carried out after all pressure tests have been completed. Before introducing hydrogen into the system all air shall be purged out using inert gas. It shall be noted that hydrogen is an intensely searching gas and this test should, therefore, be carried out in stages at progressively increased pressure, checking carefully at each stage using an approved leak-detection fluid.

4 COMMISSIONING

Before introducing hydrogen the whole system must be purged to ensure that air is removed to a level safe for hydrogen operation. This shall be established by testing that the residual oxygen concentration is less than 1 %.

Prior to the commissioning of a new hydrogen installation a thorough check shall be made to ensure that:

a) The appropriate pressure and leak tests have been carried out and documented.

b) A check has been made that the installation conforms to the process and instrumentation diagram.

c) A check has been made that the correct safety devices are fitted.

d) A check has been made that all warning and identification labels are clearly displayed and that they are correct for the product being stored.

e) An ageing pressure equipment assessment in accordance with BCGA CP 39 (17) has been conducted to identify the in-service requirements.

f) A written scheme of examination in accordance with the Pressure Systems Safety Regulations (6) has been drawn up by a competent person. A written scheme of examination shall be required for the system. The responsibility for providing and complying with this scheme lies with the user. Where systems are leased or hired the user may transfer his responsibility to the owner by written agreement (in accordance with the Pressure Systems Safety Regulations, Schedule 2 (6)).

g) An initial examination has been completed if required by the above written scheme.

h) Product release is minimised and controlled as far as is practicable.

i) Confirm that electrical equipment associated with the installation has been certified by a competent person.

j) Confirm with the user that downstream pipework and equipment is compatible with the default supply temperature and pressure conditions.

5 HANDOVER AND OPERATION

Operating instructions and flow sheets shall be permanently available at the installation and accessible to drivers and operators.

Emergency telephone numbers and emergency procedures shall be prominently displayed. Warning notices must be clearly visible from all sides of the installation.

The customer shall be instructed on the general safety aspects of hydrogen operation and on the detailed operating instructions for the specific installation. Copies of the safety data sheet shall be provided (Appendix 1 gives an example).

This may include warnings on the use of mobile phones, torches and test equipment, and the use of anti-static footwear and clothing i.e. no nylon jackets.

The requirements of the Dangerous Substances and Explosive Atmospheres Regulations (7) shall be complied with.

The owner or the installer shall be responsible for the handover to the user.

5.1 The handover. This shall include:

a) Training of user personnel in accordance with Section 6 , this may include a demonstration of the correct operation of the equipment.

b) The provision of a contact address and telephone number should the user have any questions about his installation.

c) An emergency telephone number.

d) A check to ensure that the user understands his responsibilities under the Pressure Systems Safety Regulations (6) and has made arrangements for them to be fulfilled.

5.2 Handover documents. These shall include a minimum of:

a) A manual covering safe operation of the installation.

b) An appropriate Safety Data Sheet, which gives information in accordance with the requirements of the CHIP Regulations (8) and the REACH Regulations (9). Safety Data Sheets provide information on hazardous substances to help users conduct risk assessments. They describe the hazards the product presents, and give information on handling, storage and emergency measures in case of accident.

6 PERIODIC EXAMINATION AND MAINTENANCE

The installation will constitute a Pressure System within the Pressure Systems Safety Regulations (6). As such a Written Scheme of Examination shall be drawn up by a Competent Person, covering necessary checks and maintenance activities to ensure continued safety from release of stored energy. Unless a written agreement exists with the customer and the installation remains in the ownership of the Gas Company, the responsibility for producing this Written Scheme and of carrying out the inspections under it lies with the User, i.e. the customer. Many customers who do not wish to own the installation will prefer to agree in writing with the Gas Company that this responsibility should be transferred to the Gas Company.

Maintenance involving the use of heat or spark producing tools will require the system to be purged with inert gas. Where no such hazard exists maintenance can be carried out without purging.

Vessels, and other relevant parts of the system, shall periodically be examined in accordance with the Written Scheme of Examination. Cylinders not classed as transportable pressure receptacles, by virtue of their usage, shall also be included in the Written Scheme of Examination. They will be purged with nitrogen for transport, if necessary. Examples of Written Schemes of Examination for hydrogen installations are given in Appendix 2. An ageing pressure equipment assessment in accordance with BCGA CP 39 (17) shall be conducted to identify additional ageing related in-service requirements not included in the sample written scheme in Appendix 2.

In the case of installations including medium pressure vessel(s) a log shall be maintained of the pressure cycling experienced by the vessel(s) in service. This involves recording each fill carried out with the date and the pressure before and after filling. See Appendix 2.

7 REFERENCES

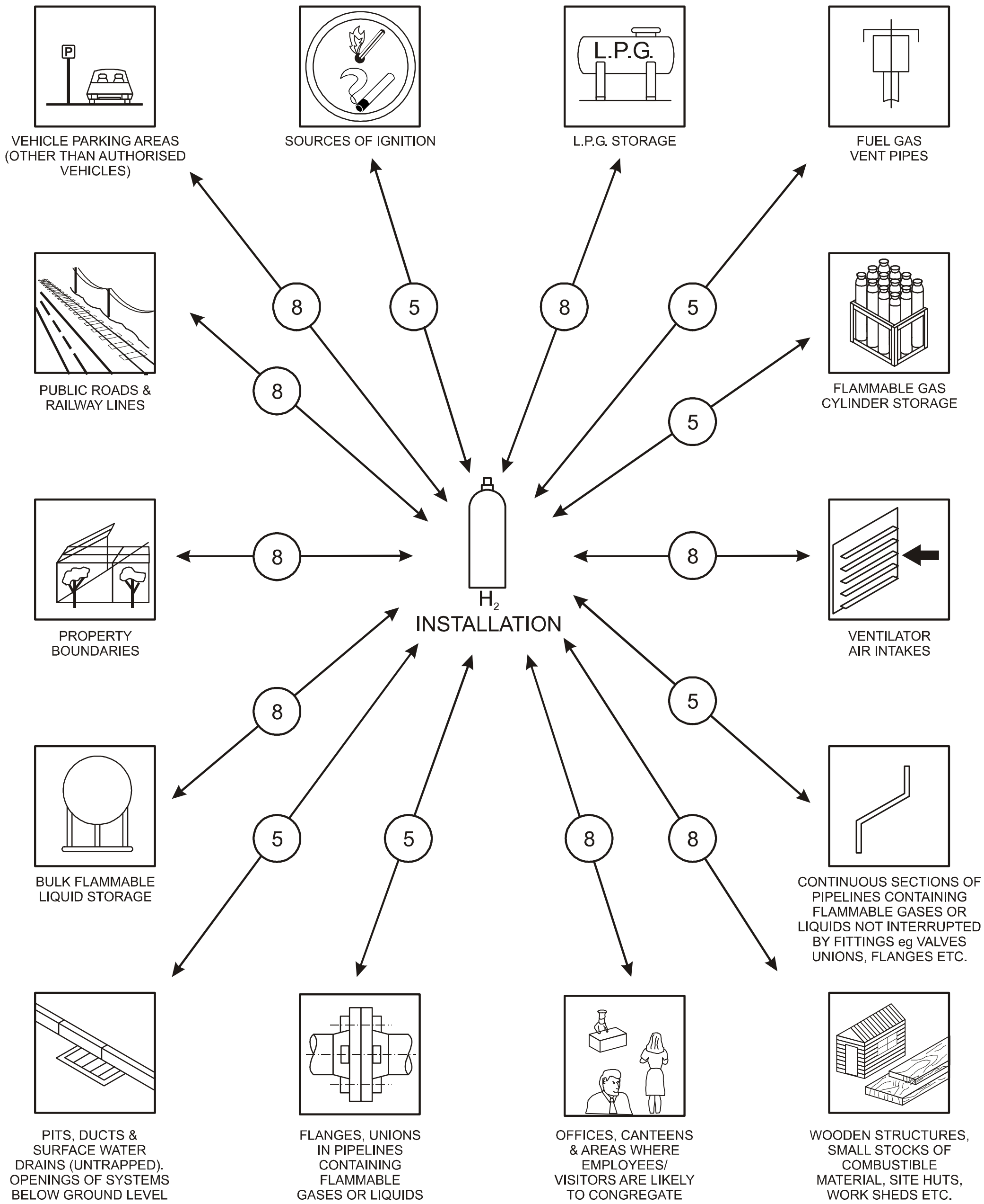
1.	SI 1996 No 192	The Equipment and Protective Systems Intended for Use in Potentially Explosive Atmospheres Regulations 1996.
2.	SI 1996 No. 341	The Health and Safety (Safety Signs and Signals) Regulations 1996.
3.	SI 1997 No. 1713	The Confined Spaces Regulations 1997.
4.	SI 1999 No. 2001	The Pressure Equipment Regulations 1999.
5.	SI 1999 No 3242	The Management of Health and Safety at Work Regulations 1999, as amended.
6.	SI 2000 No. 128	The Pressure Systems Safety Regulations 2000.
7.	SI 2002 No 2776	The Dangerous Substances and Explosive Atmospheres Regulations 2002.
8.	SI 2009 No. 716	The Chemicals (Hazard Information and Packaging for Supply) Regulations 2009 (CHIP Regulations).
9.	Regulation (EC) No 1907/2006	European Commission - Registration, Evaluation, Authorisation and restriction of Chemicals. (REACH), as amended.

10.	HSE Guidance Note GS4	Safety in pressure testing. 1998.
11.	BS 476	Fire tests on building materials and structures.
12.	BS EN 60079	Explosive atmospheres.
13.	BS EN 62305	Protection against lightning.
14.	EIGA IGC Document 6 / 02	Safety in storage, handling and distribution of liquid hydrogen.
15.	EIGA IGC Document 15 / 06	Gaseous hydrogen stations.
16.	BCGA Code of Practice 4	Industrial gas cylinder manifolds and distribution pipework (excluding acetylene).
17.	BCGA Code of Practice 39	In-service requirements of pressure equipment installed at user premises.
18.	NFPA 55	Compressed gases and cryogenic fluids code

Further information can be obtained from:

Health and Safety Executive	www.hse.gov.uk
HSE Books	www.hsebooks.co.uk
HMSO	www.hmso.gov.uk
BSi	www.bsigroup.co.uk
EIGA	www.eiga.eu
BCGA	www.bcga.co.uk
USA - National Fire Protection Association	www.nfpa.org

TABLE 1 - MINIMUM RECOMMENDED HORIZONTAL DISTANCES



If a firewall is used, a minimum separation distance of 3 m should be maintained between the wall and any part of the trailer or fixed installation that could provide a likely ignition point. The distances shown above are horizontal distances. Where specified hazards exist vertically above the installation special considerations apply. A formal risk analysis will be needed to assess the requirements.

EXAMPLE SAFETY DATA SHEET

HYDROGEN

1 IDENTIFICATION OF THE SUBSTANCE/PREPARATION AND OF THE COMPANY

MSDS Nr
067A
Product name
Hydrogen
Chemical formula
H_2
Company identification
see footer
Emergency 'phone numbers
see footer

2 COMPOSITION/INFORMATION ON INGREDIENTS

Substance/Preparation
Substance
Components/impurities
Contains no other components or impurities which will influence the classification of the product
CAS Nr
01333-74-0
EEC Nr (from EINECS)
2156057

3 HAZARDS INDENTIFICATION

Hazards identification
Compressed gas
Extremely flammable

4 FIRST AID MEASURES

Inhalation
In high concentrations may cause asphyxiation. Symptoms may include loss of mobility/consciousness. Victim may not be aware of asphyxiation.
Remove victim to uncontaminated area wearing self-contained breathing apparatus.
Keep victim warm and rested. Call a doctor.
Apply artificial respiration if breathing stopped.
Ingestion
Ingestion is not considered a potential route of exposure.

5 FIRE FIGHTING MEASURES

Specific Hazards
Exposure to fire may cause containers to rupture/explode
Burns with a colourless, invisible flame
Hazardous combustion products
None
Suitable extinguishing media
All known extinguishants can be used
Specific methods
If possible, stop flow of product. Move container away or cool with water from a protected position
Do not extinguish a leaking gas flame unless absolutely necessary. Spontaneous/explosive re-ignition may occur.
Extinguish any other fire.
Special protective equipment for fire-fighters
In confined space use self-contained breathing apparatus

6 ACCIDENTAL RELEASE MEASURES

Personal precautions
A flammable gas detector should be used before entering an area.
Evacuate area. Ensure adequate air ventilation.
Eliminate ignition sources.
Environmental precautions
Try to stop release.
Clean-up methods
Ventilate area

7 HANDLING AND STORAGE

Ensure equipment is adequately earthed.
Suck-back of water into the container must be prevented.
Purge air from system before introducing gas.
Do not allow back-feed into the container.
Use only properly specified equipment which is suitable for this product, its supply pressure and temperature. Contact your gas supplier if in doubt.
Keep away from ignition sources, including static discharge.
Segregate from oxidant gases and other oxidants in store.
Refer to supplier's container handling instructions.
Keep container below 50 ^{o}C in a well-ventilate place.

8 EXPOSURE CONTROLS/PERSONAL PROTECTION

Personal protection
Ensure adequate ventilation.
Do not smoke while handling product

9 PHYSICAL AND CHEMICAL PROPERTIES

Molecular weight
2
Melting point
-259 ^{o}C
Critical temperature
-240 ^{o}C
Relative density, gas
0.07 (air =1)
Relative density, liquid
0.07 (water =1)
Vapour pressure 20 ^{o}C
Not applicable
Solubility mg/l water
1.6 mg/l
Appearance/Colour
Colourless gas
Odour
None
Auto-ignition temperature
560 ^{o}C
Flammability range
4-75 vol % in air
Other data
Burns with a colourless, invisible flame

10 STABILITY AND REACTIVITY

Stability and reactivity
Can form explosive mixture with air.
May React violently with oxidants.

11 TOXICOLOGICAL INFORMATION

General
No known toxicological effects from this product.

12 ECOLOGICAL INFORMATION

General
No known ecological damage caused by this product.

13 DISPOSAL CONSIDERATIONS

General
Do not discharge into areas where there is a risk of forming an explosive mixture with air.
Waste gas should be flared through a suitable burner with flash-back arrestor.
Do not discharge into any place where its accumulation could be dangerous.
Contact supplier if guidance is required.

14 TRANSPORT INFORMATION

UN Nr
1049
Class/Div
2.1
ADR/RID Item No
ADR RID Item No
2, 1 ºF
ADR RID Hazard Nr
230
Labelling ADR
Label 3: flammable gas

Other transport information

Avoid transport on vehicles where the load space is not separated from the driver's compartment.
Ensure vehicle's driver is aware of the potential hazards of the load and knows what to do in the event of an accident or an emergency.
Before transporting product containers, ensure that they are firmly secured and:
- cylinder valve is closed and not leaking
- valve outlet cap nut or plug (where provided) is correctly fitted
- valve protection device (where provided) is correctly fitted
- there is adequate ventilation
- compliance with applicable regulations.

15 REGULATORY INFORMATION

Number in Annex 1 of Dir 67/548
001-001-00-9
EC Classification
F+;R12
Symbols
F+: Extremely flammable
R Phrases 12
S Phrases 9-16-33
Labelling of cylinders
Symbols Label 3: flammable gases
Risk phrases R12 Extremely flammable
Safety phrases S9/16/33 Keep container in well-ventilated place, away from ignition sources, including static discharge.

16 OTHER INFORMATION

Ensure all national / local regulations are observed.
Ensure operators understand the flammability hazard.
The hazard of asphyxiation is often overlooked and must be stressed during operator training.
Before using this product in any new process or experiment, a thorough material compatibility and safety study should be carried out.
Details given in this document are believed to be correct at the time of going to press
Whilst proper care has been taken in the preparation of this document, no liability for injury or damage resulting from its use can be accepted.

EXAMPLES OF SAFETY CHECKS AND WRITTEN SCHEMES FOR HYDROGEN INSTALLATIONS

1 Installations consisting of cylinder or trailer storage with pressure / flow control cabinet.

Safety Checks

Every year, carry out the following safety checks, which form part of normal, regular maintenance of the installation:

a) Where practicable, full leak check of system using approved leak detection fluid. If leaks are found the system shall be depressurised before repairs are carried out. Any hot work will involve purging out of hydrogen with inert gas and a re-test with nitrogen or water before re-introducing hydrogen.

b) Pressure gauges will be checked for correct operation.

c) Relief valves will be checked externally for correct seal in place, clear outlet and security of installation.

d) Physical inspection of whole system for any external damage

e) Inspect high pressure transfer hose for condition and replace if necessary.

Written scheme of examination

Every 5 years:

f) Replace high pressure transfer hose.

g) Replace relief valv*es with new or* refurbished unit.

Every 10 years:

h) Remove and replace cylinder manifolds with new or refurbished units.

i) Where necessary, purge cylinders with nitrogen, remove them and transport for re-testing.

2 Installations incorporating one or more medium pressure vessels with pressure / flow control cabinet.

Safety Checks

Every year, carry out the following safety checks, which form part of normal, regular maintenance of the installation:

a) Where practicable, full leak check of system using approved leak detection fluid. If leaks are found the system shall be depressurised before repairs are carried out. Any hot work will involve purging out of hydrogen with inert gas and a re-test with nitrogen or water before re-introducing hydrogen.

b) Pressure gauges will be checked for correct operation.

c) Relief valves will be checked externally for correct seal in place, clear outlet and security of installation.

d) Physical inspection of whole system for any external damage

e) Inspect high pressure transfer hose for condition and replace if necessary.

Written scheme of examination

5 years after putting into service and every 5 years thereafter:

f) Replace relief valves with new or refurbished unit.

g) The external examination of the medium pressure vessel(s) specified above at 2 years is to be repeated.

h) Either: Where practicable external ultrasonic flaw detection of all main seam welds, with the capability of detecting cracks 3 mm in length.

or,

internal inspection of the inside surface of the vessel(s), with magnetic particle inspection of the welds. The requirements of the Confined Spaces Regulations (3) must be complied with.

i) Replace high pressure transfer hose.

NOTE: The pressure cycling data on medium pressure vessels collected (see Section 6) shall be reviewed by the Competent Person to assess the necessary frequency of the vessel examination.

INSTALLATION IN BUILDINGS

Storage

Cylinders or bundles of hydrogen may be stored together with other common flammable gases, excluding LPG, inside a building used only for the storage of cylinders provided that the following requirements are met:

a) The building shall be of non-combustible material in accordance with BS 476 Part 4 (11).

b) The hydrogen cylinders shall be separated from other cylinders of flammable gas by not less than 1 metre.

c) The building shall have good high and low level natural ventilation to the open air. Outlet openings shall be located at the highest point of the room in exterior walls or roof. Vent openings shall have a minimum total area of not less than 2.5 % of the combined area of the walls and roof of the building.

d) Adequate explosion relief shall be provided in exterior walls or roof of the building. The total relieving area shall not be less than either the area of the roof or the area of one of the longest sides.

This explosion relief should be designed so that if an explosion occurs the pressure would be relieved and yet the explosion relief materials would not be likely to become dangerous missiles. Any combination of the following would be suitable:

(i) Walls of light non-combustible material, preferably single thickness.

(ii) Lightly fastened hatch covers.

(iii) Lightly fastened doors in exterior walls opening outwards.

(iv) Walls or roof of light design and lightly fastened.

e) Heating, if provided, shall preferably be by hot water or warm air. Where recirculatory systems are used consideration shall be given to the possibility of hydrogen contamination and adequate precautions shall be taken. The heat sources should be located remote from the building and comply with the distances set out in Table 1. Where an electrical source for heating is located in a hazardous area it shall comply with the requirements for electrical equipment outlined in Section 3.1.7.

Installation

Hydrogen systems of less than 200 cubic metres capacity may be located in buildings used for other purposes provided that the installation meets the following requirements:

a) It shall be in a well ventilated area with good high and low level natural ventilation.

b) It shall be protected against damage due to falling objects or work activity in the area.

c) It shall not be close to or below lines containing other flammable gases or liquids.

d) It shall not be located below electric lines or equipment.

e) It shall comply with the distances in Table 1.

f) It shall be defined by means of conspicuous markings and not be used for storing other materials.

APPENDIX 7 BCGA CODE OF PRACTICE 52

BRITISH COMPRESSED GASES ASSOCIATION
Registered Office: 4a Mallard Way, Pride Park, Derby, UK. DE24 8GX
Company Number: 71798, England
Tel: +44 (0)1332 225120
www.bcga.co.uk

CODE OF PRACTICE 52

The management of risks from gases in the workplace.

2023

CODE OF PRACTICE 52

THE MANAGEMENT OF RISKS FROM GASES IN THE WORKPLACE

2023

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ISSN 2398-9440

PREFACE

The British Compressed Gases Association (BCGA) was established in 1971, formed out of the British Acetylene Association, which existed since 1901. BCGA members include gas producers, suppliers of gas handling equipment and users operating in the compressed gas field.

The main objectives of the Association are to further technology, to promote safe practice and to prioritise environmental protection in the supply, use, storage, transportation and handling of industrial, food and medical gases, and we produce a host of publications to this end. BCGA also provides advice and makes representations on behalf of its Members to regulatory bodies, including the UK Government.

Policy is determined by a Council elected from Member Companies, with detailed technical studies being undertaken by a Technical Committee and its specialist Sub-Committees appointed for this purpose.

BCGA makes strenuous efforts to ensure the accuracy and current relevance of its publications, which are intended for use by technically competent persons. However, this does not remove the need for technical and managerial judgement in practical situations. Nor do they confer any immunity or exemption from relevant legal requirements, including by-laws.

For the assistance of users, references are given, either in the text or Appendices, to publications such as British, European and International Standards and Codes of Practice, and current legislation that may be applicable but no representation or warranty can be given that these references are complete or current.

BCGA publications are reviewed, and revised if necessary, at five-yearly intervals, or sooner where the need is recognised. Readers are advised to check the Association's website to ensure that the copy in their possession is the current version.

This document has been prepared by BCGA Technical Sub-Committee 6. This document replaces BCGA Guidance Note 11, *The management of risk when using gases in enclosed workplaces,* Revision 4: 2018. It was approved for publication at BCGA Technical Committee 169. This document was first published on 09/10/2023. For comments on this document contact the Association via the website www.bcga.co.uk.

JOIN US: BECOME A BCGA MEMBER

The *British Compressed Gases Association* (**BCGA**) is the leading UK Trade Association representing the interests of the industrial, food and medical gases industries, whose members include manufacturers and suppliers of bulk liquid and cylinder gases, cylinders, vessels, tanks, pipework, systems, related equipment and providers of specialist safety, health, quality, inspection and training services.

There are currently three categories of BCGA Membership designed to reflect the needs of the gases industry. These are:

Full Membership

For companies or individuals who have any practical involvement in the manufacture, mixing, handling, sales, distribution, storage or transportation of industrial, food and medical related gases or equipment.

Associate Membership

For companies or individuals who have no practical involvement (as noted in Full Membership), and is therefore for designers, consultants, training providers, academics, interested individuals involved with the industry, other associations or simply those that regularly use gases in their work environment.

Start-up Scheme

The start-up scheme is designed to support young companies, who are in the early years of their business, working in the gases industry.

As a member you'll have access to a wide variety of benefits and services to help you develop your company including:

- Certificate of Membership;
- Information about all the latest news and updates in our industry;
- The opportunity to influence oncoming regulation and guidance produced by Government;
- The opportunity to be involved in developing standards (BS EN ISO) for our industry;
- The opportunity to shape the future direction of our industry;
- Technical advice;
- Interaction with other members;
- The right to attend any of our Technical Sub-Committees;
- Access to all BCGA publications;
- The opportunity to be involved in writing BCGA publications;
- Being able to attend the BCGA Conference at Member rates;
- Appropriate listings on the BCGA website;
- Use of BCGA logo.

Becoming a BCGA member couldn't be easier. Simply download and fill in the membership application and turnover declaration forms on our website, under '**Membership**'.

If you have any questions email: admin@bcga.co.uk

CONTENTS

* Throughout this publication the numbers in [ ] brackets refer to references in Section 13. Documents referenced are the edition current at the time of publication, unless otherwise stated.

TERMINOLOGY AND DEFINITIONS

Asphyxia	An extreme condition caused by a lack of oxygen. It may be accompanied by an excess of carbon dioxide in the blood (hypercapnia). Produced by interference with respiration or insufficient oxygen in the air. Asphyxia can cause unconsciousness or death.
Confined space	As defined in the *Confined Spaces Regulations* [3]
Cryogenic liquid	Temperatures below 120 K (-153 °C) should be referred to as cryogenic temperatures. *Source: History and Origins of Cryogenics Oxford science publications edited by Ralph G Scurlock. Page 4 recommendations on low temperature terminology 1971 13th International Congress of Refrigeration.* *Reasoning; Temperatures below 120 K can generally only be reached by refrigerating machines which incorporate gas expansion and regenerative or recuperative heat exchange. To attain temperatures above 120 K a working fluid can be chosen with a critical temperature above ambient so there is no necessity for heat exchange.*
Dry ice	The solid form of carbon dioxide.
Evaporation rate	The rate at which the phase state change occurs.
Flammable gas	Gases which at 20 °C and a standard pressure of 101.3 kPa: • are ignitable when in a mixture of 13 % or less by volume with air; or • have a flammable range with air of at least 12 percentage points regardless of the lower flammability limit.
Fusible gases	A gas which is flammable and which has the ability to transport a flame from one place to another, even though the presence of the gas may in some cases only be a thin 'strand' or column.
Gas	Gas is a substance which: • at 50 °C has a vapour pressure greater than 300 kPa (3 bar); or • is completely gaseous at 20 °C at the standard pressure of 101.3 kPa
Gas density	Mass per unit volume for a gas at specified temperature and pressure. Refer to the gas Safety Data Sheet.

Gas expansion ratio	Liquid to gas volume expansion conversion – volume of gas generated from 1 volume of liquid.
Gas cylinder	A pressure receptacle of a water capacity not exceeding 150 litres.
Hazard	Any substance, condition or equipment that has the potential to cause harm to an individual or the environment.
Hypoxia	A condition where the human body, or a region of the body, is deprived of adequate oxygen.
Inert gas	A gas that is neither toxic nor flammable, but which does not support human life and which reacts scarcely or not at all with other substances.
Liquefied gas	A gas which when under pressure is partially liquid at temperatures above -50 °C. High pressure liquefied gas: a gas with a critical temperature above -50 °C and equal to or below +65 °C. Low pressure liquefied gas: a gas with a critical temperature above +65 °C.
Lower explosive limit (LEL)	The lowest concentration (percentage) of a gas or a vapour in air capable of producing a flash of fire in the presence of an ignition source.
May	Indicates an option available to the user of this Code of Practice
Permanent gas	A gas that cannot be liquefied by pressure at ambient temperature.
Pyrophoric gas	Pyrophoric gases can ignite and combust on contact with air (or oxidants). Under some conditions, ignition may not occur, resulting in the formation of a mixture of the pyrophoric gas with air or oxidant gas, which may be unstable and potentially explosive.
Reduced oxygen atmosphere	An atmosphere where the level of oxygen is reduced (or depleted) below the normal concentration in air, that is, nominally 20.9 % measured by volume.
Risk	The risk associated with any particular ‘hazard’ is commonly defined as the ‘likelihood’ (or probability) of the hazard condition arising multiplied by ‘a measure of the potential consequences’, for example, injury or death.
Risk assessment	A formal assessment of a workplace or operation, performed in order to identify hazards and evaluate the extent of risk presented by the hazard, for the purpose of either eliminating the risk or establishing suitable controls to reduce the risk to an acceptable level.
Shall	Indicates a mandatory requirement for compliance with this Code of Practice and may also indicate a mandatory requirement within UK law.

Should	Indicates a preferred requirement but is not mandatory for compliance with this Code of Practice.
Toxic gas	Any gas that, by nature of its chemistry, has a harmful effect on humans. This includes gases that may be harmful due to their corrosive properties.
Upper explosive limit (UEL)	Highest concentration (percentage) of a gas or a vapour in air capable of producing a flash of fire in the presence of an ignition source.
Workplace	Any premises, part of a premises or area that is made available to any person as a place of work and includes: • any place within the premises to which such person has access while at work; and • any room, lobby, corridor, staircase etc. where facilities are provided for use in connection with the workplace.
Workplace Exposure Limits (WEL)	Occupational exposure limits which are set in order to help protect the health of workers. Workplace Exposure Limits are concentrations of hazardous substances in the air, averaged over a specified period of time, referred to as a time-weighted average. Two time periods are used: • Long-term exposure limit (8 hours); and • Short-term exposure limit (15 minutes). Refer to HSE EH 40 [8], *Workplace exposure limits*.

CODE OF PRACTICE 52

THE MANAGEMENT OF RISKS FROM GASES IN THE WORKPLACE

1. INTRODUCTION

The key to successful safety management is the assessment and management of risks. The *Management of Health & Safety at Work Regulations* [4] require all employers to assess risk and try to anticipate what can go wrong, then to implement controls to reduce the risk. As such, safety management focuses on prevention.

This document provides guidance that can be used in the assessment of risk associated with gases in workplaces, to identify where hazardous atmospheres may occur and a range of appropriate controls.

Ambient air is primarily composed of two gases; nitrogen at approximately 78 % and oxygen at 20.9 %. Changes to the air composition can result in a potentially hazardous atmosphere. Human senses cannot detect different compositions in the atmosphere and are not a valid indicator.

Changes to the composition of the air will occur from the release of gas(es) into the local environment. Examples include evaporation, leakage and process exhaust. There is also the potential for gases to enter the workplace from external sources. Examples include the release of gases from neighbour sites, or concentrations of naturally occurring gases. The changes will be more pronounced in an enclosed space and where there is inadequate ventilation.

It should also be borne in mind that even before the introduction of stored gases into certain workplace situations, gases and low oxygen concentrations may have been generated within an enclosed space by natural decay mechanisms such as the production of hydrogen sulphide from stagnant water, or the corrosion (oxidation) of some metals which can deplete the available oxygen.

Incidents can occur unexpectedly, and may be serious, and sometimes fatal. All personnel accessing a workplace where gases may be present shall be aware of the properties and hazards of these gases and be given the necessary equipment, information, instruction and training, in particular, the hazard(s) associated with non-respirable atmospheres.

All parties should ensure they have adequate insurance to cover their activities. All parties shall ensure that they use their gases and look after gas containers and associated equipment in a safe and responsible way.

This code of practice is intended for use in conjunction with current guidance and information produced by the *Health and Safety Executive* (HSE) and other related bodies and trade associations.

2. SCOPE

This document identifies hazards from the use and the potential for the escape, leak or accumulation of gases into the workplace and the associated risks. It also provides guidance for risk assessment and appropriate mitigation measures. The scope includes all gases, whether compressed, liquefied, refrigerated or dissolved.

A workplace is a location where persons perform tasks, jobs and projects for their employer. Where gases may be present, the starting assumption is that workplaces should be regarded as Confined Spaces unless it can be demonstrated otherwise through risk assessment. The guidance provided in this document will assist with this risk assessment.

Excluded from the scope are:

- physical hazards, such as pressure, temperature, etc.;

- manual handling. Guidance is available in BCGA GN 3 [38], *Gas cylinder. Manual handling operations.*

3. ASSESSING THE RISKS ASSOCIATED WITH GASES IN THE WORKPLACE

The Management of Health and Safety at Work Regulations [4], as well as other legislation, require employers to conduct risk assessments for their activities.

When assessing the risks associated with the use of gases in the workplace there are several steps to be taken:

- identify which gases may be present on site; Refer Section 4.

- understand the hazards and properties of each of these gases; Refer to Section 5.

- determine how the gas(es) may enter the workplace, the potential quantity of gas, in what concentration and duration; Refer to Section 6.

- determine which workplaces are at risk; Refer to Section 7.

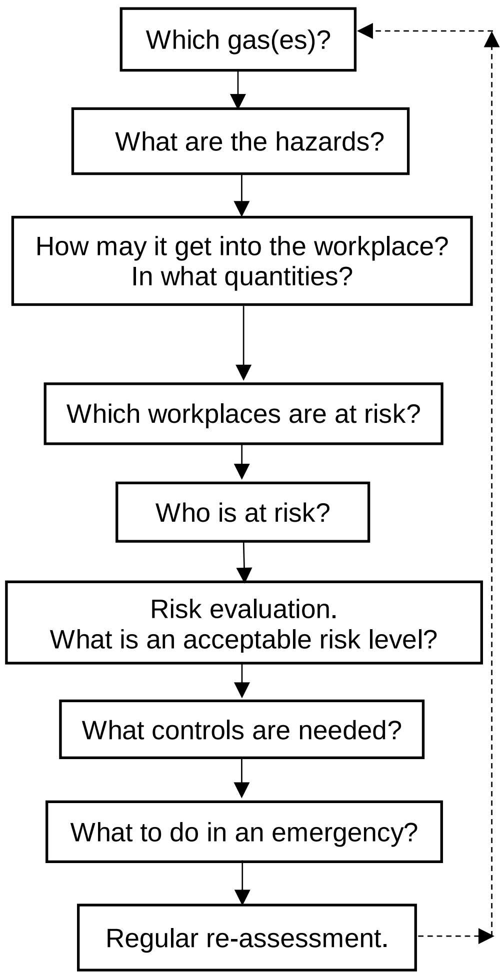
- identify who could be at risk; Refer to Section 8.

- evaluate the level of risk and acceptability; Refer to Section 9.

- implement and maintain appropriate controls; Refer to Section 10.

- consider and prepare for emergency situations; Refer to Section 11.

- carry out re-assessment on a regular basis, including when any change occurs.



BCGA provide guidance on carrying out risk assessments in BCGA TIS 49 [45], *Risk assessment considerations for activities involving compressed gas cylinders within the workplace*.

Further information on risk assessment can be obtained from the HSE, who provide a wide range of guidance on carrying out risk assessments on their website: www.hse.gov.uk/risk.

Advice on the storage, handling and use of gases can be found on the BCGA website: www.bcga.co.uk

4. THE PRESENCE AND IDENTIFICATION OF GASES

Gases can be supplied or manufactured in the workplace from various sources, for example, gas cylinders, tankers, pipelines, on-site gas generators, etc. Gases may also be present from a variety of other sources, including industrial and biological processes (directly and indirectly) and naturally, for example, the atmosphere, through human, animal and plant respiration, from percolation through the earth, etc. Section 6 provides further information.

Gas suppliers will ensure that each gas they supply is correctly identified, usually with a product label, with more comprehensive information detailed in a safety data sheet. For specific safety information and / or advice contact the gas supplier.

Gases are classified according to their hazardous properties. There are internationally recognised hazard pictograms used to identify each class of hazard, refer to Table 1 and Table 2.

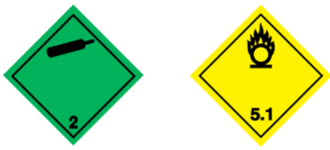
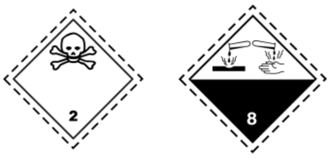
Category	**Hazard pictograms**	
	Transport	**GB CLP**
Flammable		
Oxidising		
Non-flammable Non-toxic		
Toxic Corrosive		

Table 1: Class 2 - Gases – Primary hazards

Some gases have a secondary hazard(s). This is identified by additional pictograms, as displayed to the right of the primary hazard pictogram.

An example of a gas and its hazardous properties and associated pictograms are displayed in Table 2.

Gas	**Hazard pictograms**			
	Transport: Class 2		**GB CLP**	
Carbon Monoxide, Compressed UN1016 Hazards: • Compressed gas • Toxic • Flammable				

Table 2: Example gas and its hazards

5. HAZARDS FROM GASES

Each gas has its own particular set of hazards. Refer to the relevant safety data sheet for specific product information.

The *Control of Substances Hazardous to Health (COSHH)* Regulations [6] requires that a risk assessment is conducted where exposure to any hazardous substance may occur. The HSE provide guidance on Workplace Exposure Limits in HSE EH 40 [8], *Workplace exposure limits*. Not all gases and mixtures of gases are listed, however the effect of asphyxiation is covered within HSE EH 40 [8] as a special case.

Where gases may be present in a confined space, then a risk assessment shall be carried out in accordance with the *Confined Spaces Regulations* [3].

For information on:

- asphyxia, refer to Section 5.1;
- density, refer to Section 5.2;
- liquefied, cold and cryogenic liquids, refer to Section 5.3;
- oxidising gases, refer to Section 5.4;
- atmospheres enriched with oxidants, refer to Section 5.5;
- flammable gases, refer to Section 5.6;
- inert gases, refer to Section 5.7;
- toxic gases, refer to Section 5.8;
- corrosive gases, refer to Section 5.9;

5.1 Asphyxia

The normal concentration of oxygen in air is 20.9 %. Oxygen is the only gas that supports life. The release of any gas will displace the existing atmosphere, which in turn will (other than for released air and oxygen) reduce the volume of oxygen available to breathe, this is particularly relevant in enclosed workplaces. If the oxygen concentration in the atmosphere decreases there is an increased risk of asphyxiation. Any difference in oxygen content from normal should be investigated. Table 3 sets out the effects of inhaling reduced concentrations of oxygen.

For further information, refer to:

- *European Industrial Gases Association* (EIGA) Safety Leaflet 01 [26], *Asphyxiation. The hidden killer*.

- EIGA 44 [23], *Hazards of oxygen deficient atmospheres.*

O_2 concentration Volume %	Effects and symptoms
20.9	Normal level of oxygen in the atmosphere
19.5	Minimum safe level of oxygen according to the HSE
< 19.5	Potentially dangerous.
< 10	Risk of unconsciousness followed by brain damage or death due to asphyxia is greatly increased.
< 6	Immediate loss of consciousness occurs.
0	Inhalation of only 2 breaths causes immediate loss of consciousness and death within 2 minutes

Table 3: The effects of inhaling reduced concentrations of oxygen.

5.2 Density

Knowing the density of the gases relative to air will suggest where the gas may tend to accumulate. For example, a gas with a density greater than air will tend to fall and collect in the lower areas of the workplace, such as pits, tunnels, drains, conduits, etc.

The density of a gas varies along with its temperature. As an example, a gas that is lighter than air, when cold may initially accumulate in low lying areas.

5.3 Liquefied, cold and cryogenic liquids

In addition to their gas specific hazards, liquefied, cold and cryogenic liquids have the following hazards:

- a high liquid to gas volume expansion ratio, creating a number of hazards, such as pressure build up (in a fixed volume), dispersion, etc.;

NOTE: The release of cryogenic liquid will lead to the production of a very large volume of gas (for example, oxygen, ratio of liquid to gas 1 : 860).

- the formation of vapour clouds if a liquid is released. Creating poor visibility which may result in disorientation, slips, trips, falls, etc. Until the clouds disperse a hazardous atmosphere may exist;

- the liquefaction of air. This can occur when air comes into contact with surfaces which are at a temperature below the boiling point of an air gas, for example, oxygen (typically at *circa* -183 °C). As an example, this can happen when transferring liquid nitrogen (typically at *circa* -196 °C) through uninsulated pipes which may result in the incidental condensation of liquid oxygen on the pipe outer surfaces, increasing the fire risk (through oxygen enrichment, refer to Section 5.4).

Cold gases may have the following hazards:

- cold burns, frostbite, hypothermia, lung and soft tissue damage, etc.

- embrittlement of materials and structures, leading to loss of integrity, modification of mechanical properties, etc.

5.4 Oxidising gases

Oxidising gases will support the combustion process. Many substances which would otherwise not combust, are able to combust and burn fiercely in an atmosphere enriched with oxidising gases. Substances may ignite with a lower ignition energy than that required for ignition in a non-oxidant enriched atmosphere. Typical oxidising gases include:

- nitrous oxide;

- oxygen;

- hydrogen peroxide.

NOTES:

1. Oxygen can be produced through biological action or chemical reactions, refer to Section 6.

2. Where oxidant gases are present the nominal upper and lower explosive and flammability limits for substances cannot be relied upon.

The primary hazard from oxidising gases is the increased risk of combustion, coupled with an increased intensity of combustion, refer to Section 5.5. Oxygen is a reactive gas and may cause a chemical reaction.

5.5 Atmospheres enriched with oxidants

Oxidants play a vital part in combustion mechanisms. Oxidants are not flammable, but increasing the oxidiser content in an atmosphere will increase the ignitibility and combustion rate of materials and substances. The initiation, speed, intensity and extent of combustion will depend on:

- oxidant concentration;
- pressure;
- temperature;
- contact with specific materials, type and quantity which can result in combustion or explosion.

The normal concentration of oxygen in the air is 20.9 %. However, any increase of oxidant concentration in the atmosphere considerably increases the risk of fire, the rate of propagation and the intensity. Concentrations of oxygen above 23.5 % are particularly hazardous.

In oxygen enriched air, ignition sources which would normally be regarded as harmless can cause fires, and materials which do not readily combust in air, including fire resistant materials, can and do burn vigorously. Any fire will drive the evaporation process, especially with vaporising liquefied gases, which may cause a sudden escalation of the fire.

NOTES:

1. Oil and greases and other hydrocarbons are particularly hazardous in the presence of an oxygen enriched atmosphere as they can ignite on contact with only minimum ignition energy and combust with explosive violence.

2. Oil and grease should never be used to lubricate oxygen or oxygen enriched-air equipment. Where absolutely necessary, special lubricants which are certified as compatible with oxygen (and / or other substances which may be present) shall be used.

3. Clothing, human skin and other fully or partially gas-permeable items can become saturated with oxygen. Ensure good practice is observed in relation to clothing specification, ventilation (for example, when personnel move to areas where smoking is allowed), personnel awareness, proximity to sources of ignition, etc.

Whilst it is not strictly an oxidiser, compressed air, by virtue of its pressure, volume and velocity, may have a similar effect to that of an oxidiser in increasing combustibility. Elevated levels of oxygen are, in effect, present in compressed air. For this reason, care should be taken where compressed air lines and services are present, as splits and leaks from these services can have a similar effect to the introduction of oxidisers. This should be considered in the fire risk assessment.

For specific guidance on oxygen enrichment refer to:

- HSE INDG 459 [15], *Oxygen use in the workplace. Fire and explosion hazards*.
- EIGA 4 [21], *Fire hazards of oxygen and oxygen enriched atmospheres*.

5.6 Flammable gases

Flammable gases can combust and may explode if they are ignited. The likelihood that a flammable gas will ignite is affected by its flammability range. Some common examples of the flammability ranges of specific gases in air are:

- acetylene, 2 to 85 %
- hydrogen, 4 to 75 %
- methane, 5 to 15 %

Some common examples of ignition sources are:

- electrical and electronic equipment, for example, connections, switching, overheating or faults;
- static electricity discharge. Some gases can build up a static charge as they flow over surfaces (especially dry gases);
- friction, sparks, etc.;
- chemical reaction, in particular with oxidants and pyrophoric gases;
- adiabatic compression;
- hot work;
- welding;
- naked flames;
- smoking, including from e-cigarettes (vaping).

NOTE: Some flammable gases, for example, hydrogen, readily ignites on release for a variety of reasons. Fusible gases may cause an ignition source to be conveyed from one location to another, in some cases hundreds of meters away.

The primary hazard from a flammable gas is the risk of fire and explosion, in addition flammable gases have the hazard of asphyxia and some have narcotic effects.

5.7 Inert gases

Inert gases are non-oxidising, non-flammable and non-toxic but which may dilute or displace the oxygen normally present in the atmosphere. Examples of inert gases include:

- argon;
- carbon dioxide, which has the additional hazard of hypercapnia (as below);
- helium;
- nitrogen.

The primary hazard from inert gases is asphyxia, refer to Section 5.1.

Carbon dioxide hypercapnia
Unlike other asphyxiant gases, carbon dioxide is a normal product of metabolism in human beings and takes an active part in the pulmonary gas exchange principle when people breathe.

If the concentration of carbon dioxide in the ambient air is increased and is breathed, the carbon dioxide concentration raises in the lungs and the space for fresh air (including oxygen) in the lungs decreases, compromising the pulmonary gas exchange in the lungs. This will result in elevated levels of carbon dioxide in blood and tissue, this is known as hypercapnia or hypercarbia.

CO_2 concentration Volume %	Typical effects and symptoms
0.04	Normal level in the atmosphere. NOTE: This level is gradually increasing due to the effects of climate change.
0.5	The maximum allowed Workplace Exposure Limits for an 8 hour period, refer to HSE EH 40 [8]
1 - 1.5	Slight increase in breathing rate. The maximum allowed Workplace Exposure Limit is 1.5 % in a 15 minute period, refer to HSE EH 40 [8]
3	Breathing becomes deeper and more rapid. Hearing ability reduced, headache experienced with increase in blood pressure and pulse rate.
4 - 5	Breathing and heart rate increases further. Symptoms as above, with signs of impairment becoming more evident with longer exposure and a slight choking feeling.
5 - 10	Pungent odour may be noticeable. Breathing very laboured, leading to physical exhaustion. Headache, visual disturbance, ringing in the ears, confusion probably leading to loss of consciousness within minutes.
10 - 100	In concentrations above 10 %, unconsciousness will occur in under one minute and unless prompt action is taken, further exposure to these high levels will result in death.

Table 4: The typical effects of inhaling carbon dioxide

For carbon dioxide, fatal concentrations are created well before inert gas asphyxia conditions have a significant impact. Carbon dioxide hypercapnia occurs independently of the effects of oxygen deficiency (i.e. asphyxiation, refer to Section

5.1) therefore the oxygen content alone in the air is not a comprehensive indicator of danger.

The effects of inhaling varying concentrations of carbon dioxide are given in Table 4, but it should be appreciated that the reactions of some individuals can be very different from those shown.

For additional information on the physiological hazards of carbon dioxide refer to EIGA Safety Information 24 [27], *Carbon dioxide physiological hazards "not just an asphyxiant".*

5.8 Toxic gases

Toxic gases impact adversely with people to varying degrees, from a mild irritant, to a severe reaction, including death, dependent on the exposure and the susceptibility of the individual. Typical toxic gases include:

- anhydrous ammonia
  Workplace Exposure Limit:
  - Long term exposure limit in an 8 hour period = 25 ppm
  - Short term exposure limit in a 15 minute period = 35 ppm

- carbon monoxide
  Workplace Exposure Limit:
  - Long term exposure limit in an 8 hour period = 20 ppm
  - Short term exposure limit in a 15 minute period = 100 ppm

- hydrogen sulphide
  Workplace Exposure Limit:
  - Long term exposure limit in an 8 hour period = 5 ppm
  - Short term exposure limit in a 15 minute period = 10 ppm

The primary hazard from these gases is the potential severe physiological adverse effect on health. These gases may also have asphyxia, flammable or oxidising hazards.

5.9 Corrosive gases

Corrosive gases chemically attack and damage skin, eyes and mucous membranes on contact. Typical corrosive gases include:

- chlorine
  Workplace Exposure Limit:
  - Long term exposure limit in an 8 hour period = Not applicable
  - Short term exposure limit in a 15 minute period = 0.5 ppm

- hydrogen chloride
  Workplace Exposure Limit:
  - Long term exposure limit in an 8 hour period = 1 ppm
  - Short term exposure limit in a 15 minute period = 5 ppm

- sulphur dioxide
  Workplace Exposure Limit:
  - Long term exposure limit in an 8 hour period = 0.5 ppm
  - Short term exposure limit in a 15 minute period = 1 ppm

The corrosive nature of these products may have implications for and create other (non-human) hazards, for example, mechanical considerations due to corrosion, material deterioration, etc. These hazards may in turn result in indirect health exposures, for example, due to loss of containment.

The primary hazard from these gases is the potential severe physiological adverse effect on health. These gases may also have asphyxia, flammable or oxidising hazards.

6. SOURCES OF GASES IN THE WORKPLACE

Gases may become present in the workplace from several different sources. The Employer should go through a rigorous process to identify all potential sources of gases that may be present in the workplace.

Origins of gas may include:

- processes, refer to Section 6.1;
- products of combustion, refer to Section 6.2;
- gas storage and distribution systems, refer to Section 6.3;
- from other sources, refer to Section 6.4;
- incidents, including the malicious release of a gas, refer to Section 6.5.

6.1 Processes

Gases are released through the process or from work based activity. Examples are:

- process exhaust gas, for example, inerting, blanketing, laboratory equipment, leak testing, etc.;
- welding, welding fumes, shielding gases, etc.;
- gas purging, for example, preparing equipment for use or test, purging equipment to remove residual flammable gases and vapours, etc.;
- the presence of cryogenic liquids or dry ice (resulting in evaporation or sublimation), for example, chilling and freezing, bio-storage, shrink fitting, open dewars, etc.;
- the emptying of a tank or vessel;
- medical applications, for example, the use of medical oxygen by patients (where the gas is released to atmosphere), cryotherapy, cryosurgery, etc.;
- food, beverage and modified atmosphere packaging, for example, packaging of food and other consumable goods;
- production of gases (whether planned, unplanned or as a by-product), for example, hydrogen and oxygen from electrolysis;

- maintenance and replenishment operations, for example, the coupling / uncoupling of hoses, etc.;

- deliberate introduction of gases into the workplace, for example, fire protection systems, a managed low oxygen environment (refer to Section 7), etc.;

NOTE: Almost all gases are used on a total loss basis, where they are released to atmosphere. The very few exceptions may include helium and refrigerant gases, where there are specific economic or legislative requirements.

6.2 Products of combustion

The products of combustion are hazardous, the gases released can include, for example, carbon dioxide, carbon monoxide and other noxious fumes. During combustion oxygen is consumed. There may be a combined effect from atmospheric oxygen reduction, process oxygen consumption and other reactions.

The products of incomplete combustion may generate specific hazards.

Examples of combustion are:

- welding, jointing, cutting and other allied processes, etc.;

NOTE: For the hazards of welding fume, refer to BCGA Safety Alert 3 [46], *Welding fumes*.

- heating, mobile heaters, boilers, stoves, etc.;

- the use of gases as a fuel or oxidant source.

6.3 Gas storage and distribution

Gases may be released into the workplace from relevant infrastructure or equipment. These gases may be pressurised or from containers and equipment open to the atmosphere.

Pressurised infrastructure and equipment. Gases may be released under normal operating conditions, for example, by the operation of safety devices, the connection and disconnection of equipment, etc., or unintentionally, for example, leakage, equipment failure, etc.

- Normal operating conditions.

Safety devices and pressure control devices are necessary to maintain the equipment within safe limits. Such safety devices will allow excess pressurised gas to be released safely in a controlled manner.

Gases shall be released to a safe place. This may be through the use of a suitable vent system. The location of the release point of any gases shall be subject to a risk assessment and in accordance with this Code of Practice.

The evaporation rate from liquid and refrigerated liquefied gases will vary due to a number of factors, for example, insulation efficiency, ambient temperatures, turnover of product, etc. Take this into consideration in the risk assessment.

When a single use safety pressure relief device, such as a bursting disc or a fusible plug, operates, all the positive gas pressure in the container, as well as gas created from evaporation will be released. The rate of gas released and the duration will depend upon the quantity of liquid, the pressure and the orifice dimensions.

In addition to process gases there may be other gas pressure systems on a site, for example, natural gas, compressed air, etc.

- Unintentional gas release.

Gases may be released through leakage from any part of a pressurised system. Mechanisms by which a leak may occur include, poor design, poor installation, poor maintenance, aging, corrosion, damage, fatigue, creep, over-pressure, etc.

Unintentional gas release can also occur through incorrect or accidental operation, for example, the opening of valves.

Containers and equipment open to the atmosphere. Open containers and equipment include, bio-freezers, dewars and flasks, containing a cryogenic liquid as well as quantities of dry ice.

Due to evaporation or sublimation, gases will be released directly and continuously to the atmosphere under normal operating conditions. The gas release rate will depend upon a number of factors, including, design, maintenance, insulation efficiency, ambient conditions, etc.

In addition, whenever liquid is transferred into an open container a percentage of the liquid will evaporate and be released as a gas. For guidance on the safe storage, filling and the use of dewars and flasks refer to BCGA CP 30 [32], *The safe use of liquid nitrogen dewars*.

Gases may also be released unintentionally, for example, leakage, spillage, equipment failure, etc.

For advice on the management of dry ice, refer to BCGA TIS 7 [42], *Guidelines for the safe transportation, storage, use and disposal of solid carbon dioxide (dry ice).*

6.4 Other sources of gas

Gases may be present in the workplace from several other sources. These can include:

- chemical or biochemical reactions, whether by design, inadvertent or as a by-product, examples include gases from corrosion, batteries, fermentation, decomposition, etc.;
- vapours arising from the use of solvents, for example, curing polymers, painting, cleaning, degreasing, etc.;
- naturally occurring background gases, for example, radon;
- natural gas, or other fuel gases;
- drainage systems (including methane and hydrogen sulphide), etc.;

- external sources of gas, for example, from neighbour sites.

6.5 Incidents

Consideration should be given to malicious acts or the release of gas following an incident.

7. WORKPLACES AND OTHER AREAS AT RISK

Any area where gases are introduced, either deliberately, unintentionally or from natural sources, may be affected by the hazards identified in this document. The following areas typically present an increased risk:

- internal gas storage areas. Due to the quantity of gas stored;

- confined spaces. This is a restricted space with potential poor ventilation. An example may be a lift, for advice on lifts, refer to Appendix 5;

- small enclosed areas. This is a space of limited volume with potential poor ventilation. A small enclosed area is very likely to be a confined space;

- below ground. Due to inadequate ventilation and the collection of dense gases;

- an area adjoining a place of storage / use. The unexpected release of gas into an ostensibly 'safe' area, including, for example, into air intakes, from exhausts, etc.;

NOTE: Refer to EIGA 154 [25], *Safe location of oxygen and inert gas vents*.

- poorly ventilated areas. Where there is inadequate rate of air change;

- work spaces which have a modified and non-respirable atmosphere. Examples include, greenhouses, data storage centres, agriculture produce storage areas, etc. Refer to Section 7.1;

- gas product transfer areas. Due to the release of a gas during transfer, coupling and uncoupling losses, etc.;

- beverage dispense, including waste gases such as carbon dioxide and nitrogen;

- domestic, non-industrial and non-medical environments. Examples include, domiciliary oxygen patients, using gases in cooking and with beverages, leisure gases, such as caravans, camping, BBQ's, etc., hobby activities, such as welding, etc.

When a change occurs to the workplace, gas usage or storage there may be a change in the risk and possibly the hazard. The workplace risk assessment shall be reviewed with appropriate controls put in place.

7.1 Managed low-oxygen environments

There are workplaces where the use of a controlled, low-oxygen maintained atmosphere is adopted. An example being a Hypoxic Fire Suppression System, designed to maintain a low oxygen environment to reduce the risk of fire by providing conditions where common materials cannot ignite or combust due to a lack of oxygen. The atmosphere in these environments typically contains approximately 15 % oxygen and 85 % nitrogen by volume. Where such systems are in use the oxygen deficient atmosphere should be considered as a significant hazard for humans. Risk assessment, with appropriate controls shall be implemented, such as health assessment, surveillance, atmospheric monitoring, etc.

For further information on controlled, low-oxygen maintained atmospheres refer to:

- BCGA TIS 30 [43], *Working in reduced oxygen atmospheres*;
- EIGA Safety Information Leaflet 29 [28], *Oxygen deficiency hazard associated with hypoxic fire suppression systems using nitrogen injection*.

8. WHO IS AT RISK

Any person who enters, or is present in, an area with an atmosphere containing gas mixtures different from ambient air is at risk. Non-respirable atmospheres may result from gases accumulating, whether deliberately, unintentionally or from natural sources. Examples of persons at risk include those:

- directly using the gas(es);
- in the area where the gases are being used, or where an atmosphere is being modified, for example, through combustion or hot work;
- who may be indirectly at risk, such as neighbours, the public, third parties and those 'downwind' of a gas release.

NOTE: Changes to gas concentrations may also affect machinery and animals, this may be a different effect to that experienced by humans.

9. EVALUATION OF RISK

For relevant gases a risk assessment in accordance with the *COSHH Regulations* [6] will be necessary.

As part of any risk assessment, the likelihood of a change in the atmosphere taking place and the probability of harm to people shall be determined.

Guidance on carrying out a risk assessment is provided in Section 9.4.

Carry out a preliminary assessment to establish if gases in the workplace present a hazardous atmosphere and a risk to people. Refer to Section 9.1.

The preliminary assessment should consider the following elements:

- the largest volume of gas that can leak into the workplace;
- the volume of the workplace;
- whether the resulting foreseeable gas concentration(s) exceed threshold levels. For some common gases refer to Table 5.

If the gas concentrations are in all foreseeable circumstances below the threshold level, and therefore confirmed as low risk, a more thorough risk assessment is not necessary. Record the assessment.

If the preliminary assessment indicates that the gas concentration could exceed the threshold levels, then a detailed risk assessment shall be made. Refer to Section 9.2.

NOTE: Assessing the gas concentration in a workplace is only a single assessment of one potential hazard within the workplace and all other hazards should also be considered.

Reassessment of the risk should be carried out on a periodic basis or in the event of changes taking place in the workplace which have the potential to create a different atmosphere.

9.1 Preliminary risk assessment

Preliminary risk assessment criteria:

The preliminary risk assessment considers the worst case scenario, in which the entire content of a container(s) is released instantaneously into the workplace being assessed. The assessment will need to be carried out for every foreseeable scenario, for example, each type of gas present, and shall be conducted by person(s) competent to do so.

(i) Identify the gas container(s) from which gas may foreseeably be released.

Where multiple gas containers are connected together, then the combined volume may need to be considered. Understand the relationship between container sizes and the pressure at which the gas is stored inside them. For example, cylinders with gas at a high pressure can store a greater quantity of gas than cylinders of a similar size with the gas stored at a lower pressure.

(ii) Determine the volume of gas in the identified container(s). For a:

- compressed gas cylinder.
  (pressure {bar} x water capacity {litre}) / 1000 = m^3.

- liquefied gas cylinder.
  weight of product {kg} x specific volume {at ambient temperature °C} $\{m^3/kg\} = m^3$

- cryogenic liquid container.
  (capacity of tank {litre} x expansion ratio {at ambient temperature °C}) / 1000 = m^3

(iii) Determine the free air volume in the workplace.

For a regularly-shaped workplace measure the height, width and length (in metres), then multiply together to determine the volume (m^3). From this volume deduct the volumes of any objects within the workplace, such as machines, furniture, stock, etc. (these objects reduce the volume of free air in the workplace). Allowance shall be made for maximum stocks held during worst case conditions since these extra stocks further reduce the free air volume in the workplace.

(iv) Calculation.

$$C = 100\frac{Vo}{Vr}$$

Where:

C = Percentage of gas concentration

V_O = For the result to be the percentage concentration of gas

The volume of gas, m^3

= For the result to be the percentage of oxygen

= 0.21 (*Vr* – Volume of gas in the cylinder)

Vr = The volume of free air in the workplace, m^3

(volume of workplace less volume of solid objects)

NOTE: There are example calculations in Appendix 1.

(v) Table of limits.

For some common gases the limits are referenced in Table 5. In all cases reference should be made to HSE EH 40 [8].

Gas	Limit	Comments
Oxygen	Min: 19.5 %	Refer to Section 5.1. Table 3
	Max: 23.5 %	
Carbon dioxide	Max: 0.5 %	Refer to Section 5.7. Table 4
Inert gases, for example, nitrogen		Use oxygen minimum level
Flammable gases	Max: 25 % of the LEL	
Toxic		Use WEL for specific gas

Table 5: Limits for some common gases

(vi) Evaluation.

If the gas concentrations are within the limits in HSE EH 40 [8] then the workplace can be considered low risk and a more thorough risk assessment is not necessary.

Record the preliminary assessment.

The preliminary assessment should be reviewed on a periodic basis and whenever changes occur in the workplace.

If the preliminary assessment indicates that the gas concentrations exceed the limits in Table 5, or are finely balanced, or have an unacceptable risk, a detailed risk assessment is necessary. Refer to Section 9.2.

9.2 Detailed risk assessment

A more detailed risk assessment is required to take into account normal and abnormal scenarios. This shall be carried out by person(s) competent to do so, considering all applicable variables.

The following should be considered for all gases:

- identify the specific gas(es) and its properties. This includes:
  - variation in effect due to temperature, density, pressure, physical state, etc.;
  - any effects arising from the mixing of gases;
  - the resulting atmosphere in the event of a gas release. Some calculations which may be used are set out in Section 9.3.

NOTE: Gas dispersion studies and modelling options are obtainable where required by the risk assessment. Advice may be sought from specialist suppliers.

- potential release points. Taking into account the release rate, duration, volume and likelihood of release. Release points may include:
  - venting via safety relief devices;
  - deliberate release, for example, venting;
  - natural boil off from cryogenic liquids;
  - dry ice sublimation;
  - process exhaust, equipment and flues;
  - unintended leakage, for example, spills, leaking joint(s), damage to pipework / equipment;
  - inadvertent or incorrect operation of equipment;
  - release during connection / disconnection of hoses and regulators.

Guidance on separation distances is available in BCGA GN 41 [41], *Separation distances in the gases industry*.

- the transfer of released product into other spaces. Examples include, ventilation systems, air intakes, elevations (basement, top floors, etc.), lift shafts, gulleys, trenches, etc.;
- the free air volume of the space, in which the atmosphere may be present;
- ventilation. This may be natural or forced. Determine the air changes per hour;

- occupancy of the spaces where a release may take place. Take into account the presence of vulnerable receptors and populations, access controls and restrictions, etc.

Other factors to consider for flammable gases include:

- potential sources of ignition.

For flammable gases (and indeed all compressed gases) a *Dangerous Substances and Explosive Atmospheres Regulations* **(**DSEAR) [7], risk assessment will be necessary. Guidance is available in BCGA GN 13 [39], *DSEAR Risk Assessment guidance for compressed gases*.

Other factors to consider for oxidising gases include:

- increased fire risk;

- health risk from high oxygen concentrations.

Other factors to consider for intoxicating, toxic and corrosive gases include:

- acute and chronic health effects.

Once released, a gas will be free to move and its movement will be influenced by any ventilation conditions or systems and / or by the prevailing weather conditions. Be aware of the hazard not only from the gas supplies on site, but also from those held by neighbour(s).

9.3 Calculations for use with risk assessments

The following calculation may be used to approximate the resulting atmosphere where the release rate, the workplace free air volume, ventilation and release duration is known. This method can be used to establish the hazard resulting from a gradual release of product (non-respirable gas) into the workplace, for example, where an instantaneous release of all the available gases is unlikely to occur due to system design / method of use but where a build-up of an unsafe atmosphere can occur over a period of time.

NOTE: These equations provide an approximate value, but can be a convenient means to determine potential changes. Where more precise calculations are required consult with a competent ventilation Engineer.

This equation gives the approximate resulting oxygen percentage concentration (OC_t) after time (t) and may be used to establish the asphyxiation and oxygen enrichment risk:

$$OC_t = 100\left(0.21 + \left(\left[\frac{0.21 \times n}{\left(\frac{L}{Vr}\right) + n}\right] - 0.21\right)\left(1 - e^{-t/m}\right)\right)$$

and for long periods (t tending to infinity):

$$OC_\infty = 100 \times \left(\frac{Vr \times 0.21 \times n}{L + (Vr \times n)}\right) \quad \text{approximately}$$

This equation gives the approximate resulting gas percentage concentration (GC_t) after time (t) and may be used to establish the intoxicating (CO_2), toxic or flammable risk:

$$GC_t = \left(100 - \left(100 \times \left[\frac{Vr \times n}{L + (Vr \times n)}\right]\right)\right)\left(1 - e^{-t/m}\right)$$

and for long periods (t tending to infinity):

$$GC_\infty = 100 - \left(100 \times \left[\frac{Vr \times n}{L + (Vr \times n)}\right]\right) \quad \text{approximately}$$

Where:

OCt	=	Oxygen percentage concentration after defined time
OC_∞	=	Oxygen percentage concentration after long periods (days)
GCt	=	Gas percentage concentration after defined time
GC_∞	=	Gas percentage concentration after long periods (days)
L	=	Gas release rate, m^3/h
Vr	=	The volume of free air in the workplace, m^3
n	=	The number of workplace air changes per hour
t	=	Time, hours
e	=	2.72
m	=	$\frac{Vr}{L + (Vr \times n)}$

A worked example of the above method is given in Appendix 1.

9.4 Risk management

Risk management is a step-by-step process for controlling health and safety risks caused by hazards in the workplace. Risk is the combination of the likelihood of harm occurring and the severity of that harm. Carrying out a risk assessment is just one part of the overall process used to control risks. A risk assessment shall be carried out by a competent person. The risk assessment shall take into account:

- people;
- the environment; and
- property.

A risk matrix can be used to help work out the level of risk associated with a particular issue. It does this by categorising the likelihood of harm and the potential severity of the harm. This is then plotted in a matrix. The risk level determines which risks should be tackled in which order. However, it does require appropriate competence to judge the relative likelihood of harm accurately.

Advice on carrying out a risk assessment for activities involving gas cylinders is provided in BCGA TIS 49 [45].

The HSE provide advice on managing risks and risk assessment at work on their website. http://www.hse.gov.uk/risk/faq.htm#hierarchy

Any risks which are determined to be unacceptable (i.e. are not managed to a level characterised as '*as low as reasonably practicable*') will require further controls. Refer to Section 10.

Carry out a review of the risk assessment on a regular basis. This may include:

- when a change occurs to the workplace (for example, personnel changes);
- changes to gas types, gas usage or storage;
- changes to procedures, including when gaseous equipment is installed, replaced or removed;
- when problems occur, including following any incidents or near misses.

10. IDENTIFYING RISK CONTROL MEASURES

Risks should be reduced to the lowest reasonably practicable level by taking preventative measures, in order of priority of effectiveness. This is what is meant by a hierarchy of control. The list below sets out a recommended order to follow when planning to reduce risks. To reduce the risk it may be necessary to use more than one type of control. Carefully consider each of the headings in the order shown, do not simply jump to the easiest control to implement.

(i) **Elimination**. Redesign the task or process so that the hazard is entirely removed or eliminated. Refer to Section 10.1.

(ii) **Substitution**. Replace the material, substance or process with a less hazardous one. Refer to Section 10.2.

(iii) **Engineering controls**. Use work equipment or other measures to control risks from gases. Give priority to measures which protect collectively over individual protection in line with *The Management of Health and Safety at Work Regulations* [4]. Refer to Section 10.3.

(iv) **Administrative controls**. Identify and implement robust and effective procedures to ensure safety. Refer to Section 10.4.

(v) **Personal protective equipment**. Only to be considered after all the previous measures have been applied and found not to have controlled the risks to the lowest reasonably practicable level. Refer to Section 10.5.

Controls are those that will reduce the probability of a hazard for example, a hazardous atmosphere due to a gas release. The control of gas usage, adequate ventilation and the location of the gas storage are the key risk controls.

10.1 Elimination

Where it is necessary to have gases on a site, then remove the possibility of a hazardous atmosphere being created. Where possible gas should be prevented from entering any space where it may create danger.

Store gases and carry out operations that require a gas, outside in an adequately ventilated and dedicated space. Guidance on separation distances is available in BCGA GN 41 [41].

For storage of gases refer to:

- BCGA CP 26 [31], *Bulk liquid carbon dioxide at users' premises.*
- BCGA CP 36 [33], *Cryogenic liquid storage at users' premises.*
- BCGA CP 44 [36], *The storage of gas cylinders*.
- BCGA CP 46 [37], *The storage of cryogenic flammable fluids*.

10.2 Substitution

Consider the properties of the gases in use and the environment(s) in which they will be used or may enter. Use the most appropriate gas, with the least hazard, for any particular situation. Examples include:

- when carrying out leak testing, instead of a flammable gas (hydrogen) use a non-flammable gas (helium).

  NOTE: This will help manage flammability risks, but there remains a need to determine and appropriately manage other risks, such as asphyxiation.

- when welding and cutting in confined spaces, such as underground, use a lighter than air gas, such as acetylene, rather than a heavier than air gas such as *liquefied petroleum gas* (LPG).

  BCGA TIS 32 [44], *Acetylene or propane (for welding, cutting and allied processes)*, provides advice on choosing welding fuel gases.

- the management of stocks of gases to keep the minimum necessary on site.

10.3 Engineering controls

Prior to selecting engineering controls, understand which gases are on site, their properties, the duration of use, the quantities, their location and their application in the workplace. Engineering controls can isolate gases from personnel, may provide early detection of an accumulation of gas or control the release of gases by methods such as enclosing or extracting.

Engineering controls shall be designed, installed and maintained by competent people.

Attention is drawn to the fact that equipment alone does not provide absolute protection, since such equipment can malfunction, be poorly maintained, be operated by non-competent persons, be out of calibration, be poorly located or be ignored.

Some types of engineering control include:

- **Workplace ventilation**. This can be achieved by increasing natural ventilation (for example, by the use of additional louvres), using a whole workplace forced air ventilation system or providing local exhaust ventilation systems.

For further information on workplace ventilation refer to Appendix 2.

- **Atmospheric monitoring equipment**. Atmospheric monitoring equipment may be used to monitor the atmosphere in a specific area and to warn of changes which could create a hazardous atmosphere. These may include fixed or portable detection devices or a combination of both, as determined by risk assessment.

Independent sensors may be required for individual gases. As an example, separate sensors are required to measure carbon dioxide enrichment and to measure oxygen depletion, and different sensors may be needed to measure each of these within a specific background.

For further information on atmospheric monitoring refer to Appendix 3.

- **Pipework**. Distribute gas in to the work area through pipework of suitable integrity, at the lowest possible pressure and at a restricted flow-rate suitable for the work task and suitable for the ventilation capability. Provide over-pressure and flow-limitation control accordingly. Refer to BCGA CP 4 [29], *Gas supply and distribution systems (excluding acetylene),* and BCGA CP 5 [30], *Gas supply and distribution systems. Acetylene*.

- **Exhausts**. Ensure that the exhausts from machines and pressure relief valves, vents, etc. are directed to a safe area. Refer to BCGA CP 4 [29] and EIGA 154 [25].

- **Exclusion (using engineering controls)**. Use a dedicated area that separates personnel from places where the gas might adversely affect the atmosphere, for example, a fume cupboard, a safety cabinet or an isolated compartment, where the activity exclusively and safely takes place.

- **Materials selection**. Select appropriate materials suitable for the hazards. Examples are:

    - materials which have an appropriate low-temperature rating where cryogenic gases are present;

    - the use of appropriate materials for specific gases, for example, steels which are compatible with hydrogen (and are not susceptible to hydrogen embrittlement), non-sparking tools, where there is a potential flammable atmosphere, oxygen compatible and clean items for oxygen service, non-magnetic materials for use in and around very low temperature cryogenic gases, i.e. hydrogen and helium, etc.

- **Pressure safety devices**. Examples include:

    - anti-whip restraints;

    - specialist features to safely relief pressure;

- protective barriers.

10.4 Administrative controls

Design and put in to place safe systems of work for normal and non-routine activities for both operation and maintenance. For example, through:

- competence, by the provision of suitable information, instruction, supervision and training to those who need it. Guidance is available in BCGA GN 23 [40], *Gas safety. Information, instruction and training*.

- increasing hazard awareness using suitable safety signs and warning notices, in accordance with *The Health and Safety (Safety Signs and Signals) Regulations* [2], as well as other appropriate audio-visual safety systems;

- reducing the time workers are exposed to hazards (for example, by job rotation);

- restricting access to hazards;

- the use of work permit systems to control specific risks. For information on work permit systems, refer to EIGA 40 [22], *Work permit systems*, and HSE HSG 250 [13], *Guidance on permit-to-work systems. A guide for the petroleum, chemical and allied industries*;

- health surveillance;

- controls for making safe on completion of a work activity, for example, ensuring sufficient ventilation of clothing after exposure to an oxygen rich environment (refer to EIGA 4 [21]), venting and purging of a flammable gas, etc.

- controls for mechanical and electrical integrity, ensuring all examination, inspection and maintenance activities are carried out, refer to BCGA CP 39 [34], *In-service requirements of pressure equipment (gas storage and distribution systems)*;

- implementation and practice of emergency operating procedures, to manage and prevent hazardous situations from escalating. Refer to Section 11.

Exclusion (using administrative controls). A safe system of work can include administrative controls to help ensure safety of a particular task.

Special considerations are required for access to, and work in, a confined space. Refer to Appendix 4.

10.5 Personal protective equipment.

A work activity risk assessment shall determine the requirement for the use of hazard controls, including, where necessary, for personal protective equipment (PPE).

Only after all other levels of control have been determined to be ineffective in controlling risks to a reasonably practicable level, should PPE be considered as a control.

Even with PPE, if the risk is not reduced to as low a level as is reasonably practicable, then the activity should not proceed.

HSE L25 [16], *Personal Protective Equipment at Work,* provides guidance on the *Personal Protective Equipment Regulations* [5]. EIGA 136 [24], *Selection of personal protective equipment*, provides guidance for selecting and using PPE at work.

Where PPE is required, a PPE assessment shall be carried out in accordance with the *Personal Protective Equipment Regulations* [5]. This shall be carried out by competent persons.

The selection of PPE shall be appropriate for the hazard, task, location and individuals.

PPE shall be provided by the employer, along with the necessary information, instruction, training and supervision for its use. The employer shall ensure that employees wear any PPE required.

Cleaning and maintenance (including its replacement) shall be included in the PPE management system. Suitable storage shall be provided for PPE when it is not in use.

The effectiveness of the PPE shall be reviewed periodically.

Emergency situations may require different or additional PPE.

Users shall take into account the requirements of other applicable Regulations, such as the *COSHH Regulations* [6], in relation to assessing risks, along with any relevant equipment publications, manufacturers information and the product(s) safety data sheet.

NOTE: Any equipment that has a personal protective function is classified as PPE, for example, a personal atmospheric monitor.

Examples of PPE include:

- personal atmospheric monitors, worn by an individual;
- breathing apparatus (for emergency activities or special short term cases);
- flame retardant clothing (especially for flammable gases);
- suitable clothing for specific environments, for example, insulative / thermal clothing for cold atmospheres, anti-static footwear for flammable-gas environments, etc.;
- separate and / or specific PPE for different products, for example, when handling cryogenic liquids.

11. EMERGENCY SITUATIONS

Prepare for and understand how to deal with all emergency situations.

An emergency plan shall be established and implemented. The plan shall be a controlled document, issued to and understood by all relevant personnel. Traditionally a site is covered by a single plan, however it may be appropriate to have discreet plans for specific areas.

Wherever gases are in use or in storage, the emergency plan shall be established and implemented. The emergency plan should include:

- identifying an emergency situation;

- raising the alarm;

- immediate actions for persons affected;

- risk assessed prevention of escalation. The usual course of action will be for evacuation to a safe place, however there may be opportunity (on a risk assessed basis) to prevent escalation where it is safe to do so, for example:

    - local isolation of the gas supply;

    - the use of automated or remote shutdown to isolate;

    - the use of safety systems, for example, deluge, on the incident site;

    - the removal of equipment or stock from the immediate area which would contribute to an escalation event;

    - tackle a fire using available fire-fighting equipment;

    - increase available ventilation, if appropriate;

    - containment of the incident, if appropriate.

- safe evacuation, to a safe point of assembly, and roll-call. The point of assembly may be a shelter-in-place arrangement to provide protection from the gas or other local hazards;

- definition of roles and responsibilities, including clarification of person in charge (these arrangements shall cover all shift patterns and foreseeable circumstances);

- search and rescue arrangements. Refer to the note below;

NOTE: Many deaths in confined spaces are of those who attempt rescue. It cannot be over-emphasized that ill-considered rescue attempts shall be avoided.

When working in or near areas where gases are in use or in a confined space, if a person suddenly collapses and no longer gives any sign of life, assume that the person may lack oxygen due to the presence of an asphyxiating atmosphere. Prevent colleagues rushing to their aid unless competent and equipped to do so, for example, with breathing apparatus.

WARNING: Do not enter a confined space without adequate preparation and risk assessment; there is the potential that the ‘rescuer’ will become the second victim. Get proper assistance and support, and work according to the confined space entry procedures and an emergency plan.

- assessment of potential external escalation. Determine who else may be affected? Secondary or collateral hazards due to the effect of the emergency or the foreseeable progress of an emergency situation. These may include, for example,

- the formation of unusual gas mixtures, fumes, vapours or atmospheres;
- machinery damage / malfunction resulting in secondary hazards;
- emergency cascade or domino effects;
- access or egress restrictions, etc.

- communication (to other stakeholders, including workforce, management, neighbours, emergency services, etc.), including sharing of the emergency plans, or relevant parts thereof. The emergency plan should list contact information for all other stakeholders, including neighbours;

- when and how to call the emergency services. Consider if pre-contact with emergency services (especially the Fire and Rescue Service) might be mandated, suitable and beneficial;

- management of the incident and transition to recovery phase;

- assessment of situation leading to recovery procedures. When is it safe to return? Sampling of the atmosphere. Who is authorised to give the 'all clear'? etc.;

- recovery;

- incident investigation. Preservation of evidence;

Testing and recording of emergency plan exercises, including out-of-hours.

On completion of all tests and incidents take account of any lessons learned. Review and update the emergency plans, risk assessments and control measures.

12. SECURITY

All gases are hazardous substances. Access to gases, and operation of pressure systems, shall only be by authorised and competent personnel.

A documented security vulnerability risk assessment shall be carried, to cover all aspects of storage, transportation and use. Refer to BCGA CP 40 [35], *Security requirements for the industrial, medical and food gases industry*.

Advice on security can be obtained from the Gas Supplier and from BCGA.

13. REFERENCES

Document Number		Title
1.	SI 1996 No. 192	The Equipment and Protective Systems Intended for Use in Potentially Explosive Atmospheres Regulations 1996.
2.	SI 1996 No. 341	The Health and Safety (Safety Signs and Signals) Regulations 1996.
3.	SI 1997 No. 1713	Confined Spaces Regulations 1997.
4.	SI 1999 No. 3242	The Management of Health and Safety at Work Regulations 1999.
5.	SI 2002 No. 1144	The Personal Protective Equipment Regulations 2002
6.	SI 2002 No. 2677	The Control of Substances Hazardous to Health Regulations 2002 (COSHH).
7.	SI 2002 No. 2776	The Dangerous Substances and Explosive Atmospheres Regulations 2002 (DSEAR).
8.	HSE EH 40	Workplace exposure limits.
9.	HSE Research Report RR 973	Review of alarm settings for toxic gas and oxygen detectors.
10.	HSE HSG 37	An introduction to local exhaust ventilation.
11.	HSE HSG 54	Maintenance, examination and testing and testing of local exhaust ventilation.
12.	HSE HSG 173	Monitoring strategies for toxic substances.
13.	HSE HSG 250	Guidance on permit-to-work systems. A guide for the petroleum, chemical and allied industries.
14.	HSE INDG 258	Confined spaces. A brief guide to working safely.
15.	HSE INDG 459	Oxygen use in the workplace. Fire and explosion hazards.
16.	HSE L25	Personal Protective Equipment at Work.
17.	HSE L101	Safe work in confined spaces. Confined Space Regulations 1997. Approved Code of Practice and guidance.
18.	BS 5925	Code of Practice for ventilation principles and designing for natural ventilation.
19.	BS EN 60079	Explosive atmospheres. Part 29-2: Gas detectors. Selection, installation, use and maintenance of detectors for flammable gases and oxygen.

20.	PD CLC IEC/TR 61508	Functional safety of electrical/electronic/programmable electronic safety-related systems.
21.	EIGA 4	Fire hazards of oxygen and oxygen enriched atmospheres.
22.	EIGA 40	Work permit systems.
23.	EIGA 44	Hazards of oxygen deficient atmospheres.
24.	EIGA 136	Selection of personal protective equipment.
25.	EIGA 154	Safe location of oxygen and inert gas vents.
26.	EIGA Safety Leaflet 01	Asphyxiation. The hidden killer.
27.	EIGA Safety Information Sheet 24	Carbon dioxide physiological hazards "Not just an asphyxiant".
28.	EIGA Safety Information Sheet 29	Oxygen deficiency hazard associated with hypoxic fire suppression systems using nitrogen injection.
29.	BCGA Code of Practice 4	Gas supply and distribution systems (excluding acetylene).
30.	BCGA Code of Practice 5	Gas supply and distribution systems. Acetylene.
31.	BCGA Code of Practice 26	Bulk liquid carbon dioxide at users' premises.
32.	BCGA Code of Practice 30	The safe use of liquid nitrogen dewars.
33.	BCGA Code of Practice 36	Cryogenic liquid storage at users' premises.
34.	BCGA Code of Practice 39	In-service requirements of pressure equipment (gas storage and distribution systems).
35.	BCGA Code of Practice 40	Security requirements for the industrial, medical and food gases industry.
36.	BCGA Code of Practice 44	The storage of gas cylinders.
37.	BCGA Code of Practice 46	The storage of cryogenic flammable fluids.
38.	BCGA Guidance Note 3	Gas cylinder. Manual handling operations.
39.	BCGA Guidance Note 13	DSEAR Risk assessment guidance for compressed gases.

40.	BCGA Guidance Note 23	Gas safety. Information, instruction and training.
41.	BCGA Guidance Note 41	Separation distances in the gases industry.
42.	BCGA Technical Information Sheet 7	Guidelines for the safe transportation, storage, use and disposal of solid carbon dioxide (dry ice).
43.	BCGA Technical Information Sheet 30	Working in reduced oxygen atmospheres.
44.	BCGA Technical Information Sheet 32	Acetylene or propane (for welding, cutting and allied processes).
45.	BCGA Technical Information Sheet 49	Risk assessment considerations for activities involving compressed gas cylinders within the workplace.
46.	BCGA Safety Alert 3	Welding fumes.
47.	CoGDEM	The CoGDEM guide to gas detection.

Further information can be obtained from:

UK Legislation	www.legislation.gov.uk
Health and Safety Executive (HSE)	www.hse.gov.uk
British Standards Institute (BSI)	www.bsigroup.co.uk
British Compressed Gases Association (BCGA)	www.bcga.co.uk
European Industrial Gases Association (EIGA)	www.eiga.eu
The Council of Gas Detection and Environmental Monitoring (CoGDEM)	www.cogdem.org.uk

EXAMPLE CALCULATIONS

Preliminary Assessment: Example for an asphyxiant gas
Refer to Section 9.1.

One nitrogen 50 litre cylinder charged to 200 bar being used in a workplace with a free air volume of 75 m^3.

$$C = 100\frac{Vo}{Vr}$$

Where:

Water capacity = 50 litre
Pressure = 200 bar
Vr = 75 m^3
V_O = 0.21 (Vr – Volume of gas in cylinder)

Volume of gas in the cylinder = $\dfrac{pressure \times capacity}{1000} = \dfrac{200 \times 50}{1000}$ = 10 m^3

$Vo = 0.21\,(75 - 10)$ = 13.65 m^3

Resulting oxygen concentration, C $= 100\dfrac{Vo}{Vr} = 100 \times \dfrac{13.65}{75}$ = 18.2 %

This oxygen concentration is below the minimum workplace concentration for normal working (refer to Section 5.1).

However, the instantaneous release of the whole contents of a compressed gas cylinder is an unlikely event, and not foreseeable as part of normal working. Thus the requirement of specific preventative controls should be assessed but are unlikely to be required in this case.

Preliminary Assessment: Example for a liquefied gas
Refer to Section 9.1.

One 6.35 kg carbon dioxide cylinder being used in a workplace with a free air volume of 75 m^3.

$$C = 100\frac{Vo}{Vr}$$

Where:

Weight = 6.35 kg
Vr = 75 m^3

VO = Volume of gas in the cylinder = *Weight (of product) x Specific Volume (at 1.013 bar & 15 °C)* = 6.35 x 0.5344 = 3.4 m^3

Resulting gas concentration, $C = 100\frac{Vo}{Vr} = 100 \times \frac{3.4}{75} = 4.5\ \%$

HSE have defined a workplace exposure limit for carbon dioxide of 0.5 % averaged over 8 hours, with a maximum exposure of 1.5 % for short periods of 15 minutes (refer to Section 5.7). The volume of carbon dioxide from this 6.35 kg cylinder could produce a concentration of 4.5 % in case of complete loss via, for example, a bursting disc failure. This would produce a dangerous atmosphere and preventive measures are necessary.

Detailed Risk Assessment: Example
Refer to Section 9.3

An inert gas is being used in a work place with a free air volume of 32 m^3, the gas flow rate is 1.1 m^3/h, the air changes are 0.4 per hour and the time taken to complete the job is 2 hours.

To establish the effect of this activity on the workplace atmosphere after 2 hours the following formula is used:

$$OC_t = 100\left(0.21 + \left(\left[\frac{0.21 \times n}{\left(\frac{L}{Vr}\right) + n}\right] - 0.21\right)\left(1 - e^{-t/m}\right)\right)$$

Where:

OC_t	=	Oxygen percentage concentration after defined time
L	=	1.1 m^3/h
Vr	=	32 m^3
n	=	0.4 per hour
t	=	2 hours
e	=	2.72
m	=	$\frac{Vr}{L+(Vr \times n)} = \frac{32}{1.1 + (32 \times 0.4)} = 2.3$

$$OC_t = 100\left(0.21 + \left(\left[\frac{0.21 \times 0.4}{\left(\frac{1.1}{32}\right) + 0.4}\right] - 0.21\right)\left(1 - 2.72^{-2/2.3}\right)\right)$$

$$OC_t = 100\left(0.21 + \left(\left[\frac{0.084}{0.434}\right] - 0.21\right)(0.58)\right)$$

$$OC_t = 100\left(0.21 + (-0.0165)(0.58)\right)$$

$$OC_t = 100\left(0.21 + (-0.0096)\right)$$

$$OC_t = 100\ (0.2004)$$

$$OC_t = 20.04\ \%$$

The concentration of oxygen in the air is 20.04 %.

The oxygen concentration in the workplace has dropped but is still above the minimum recommended (19.5 %, refer to Section 5.1).

However, it should be noted that if the activity continues for a further period the oxygen concentration will drop further. Increasing the ventilation air change ratio is an option to maintain the oxygen level at a safe level.

WORKPLACE VENTILATION

Ventilation can be used to directly protect individuals or indirectly by managing the atmosphere. Additional ventilation can be achieved by increasing natural ventilation, using a whole workplace forced air ventilation system or by providing local exhaust ventilation systems (LEV).

Guidance on ventilation is available from:

- HSE website - https://www.hse.gov.uk/ventilation/
- HSG 37 [10], *An introduction to local exhaust ventilation*;
- HSG 54 [11], *Maintenance, examination and testing and testing of local exhaust ventilation*;
- BS 5925 [18], *Code of Practice for ventilation principles and designing for natural ventilation*.

Building size, ventilation capacity, system pressures etc. shall each be considered in specific cases. The following general guidelines apply:

- ventilation should be continuous or interlocked. If interlocked, it may be with the gas supply and / or with an access door(s) such that the ventilation system operates whenever gas is being supplied or when personnel are likely to access the relevant area. Interlocks functionality shall be checked routinely in accordance with a Safe Operating Procedure.
- if a forced air ventilation system is used, it should be connected to the atmospheric monitoring equipment system to allow automatic operation, refer to Appendix 3.

  NOTE: Where there is a reliance on forced air ventilation to prevent a hazardous accumulation of gases the ventilation system shall be verified at least every 14 months, refer to the *COSHH Regulations* [6].

- the ventilation system design should ensure adequate airflow around the operating area to prevent danger.
- the ventilation system shall be compatible with all the gases that may be present. For example, where a flammable or oxidant gas is in use then the system may be within the scope of DSEAR [7] and the *Equipment and Protective Systems Intended for Use in Potentially Explosive Atmospheres Regulations* [1]. If in scope, a specific risk assessment shall be carried out. Guidance is available in BCGA GN 13 [39].
- devices indicating the effective operation of the ventilation system (air flow) should be included in the design. Indicating devices may include:
  - warning lights;
  - ‘streamers’ in the fan outlet;

  - audible alarm on failure;

  - flow switches in the suction channels.

- local exhaust ventilation systems should be clearly identified;

- the exhaust shall be directed to a safe, out door, well-ventilated area;

- the ventilation system shall be subject to a planned inspection and maintenance regime, including periodic testing to ensure it remains in a serviceable condition, for example, there is no unacceptable damage and there are no obstructions or blockages.

ATMOSPHERIC MONITORING EQUIPMENT

Atmospheric monitoring equipment (often referred to as ‘gas detection equipment’) is used to monitor the atmosphere in a specific area and to warn of changes which could create a hazardous atmosphere. These may be fixed or portable devices or a combination of both.

The requirement for and location of atmospheric monitoring equipment shall be determined by risk assessment. The risk assessment should indicate the appropriate location(s) for the detector / monitor measurement head(s). This should take into account the properties of the gases, potential gas release points and locations where a gas may accumulate.

Separate gas sensors (and where necessary, systems) shall be provided for the different foreseeable atmospheric monitoring duties. For example, separate sensors are necessary for carbon dioxide enrichment and for oxygen deficiency.

In many circumstances fixed atmospheric monitoring equipment is preferable to personal mobile equipment. Fixed equipment has an improved ability to detect hazards before a person is exposed, whereas personal equipment generally confirms that the person is about to be or may already be exposed to the hazard (which may be too late). Fixed equipment also covers an area, rather than the spot location where an individual happens to be.

Atmospheric monitoring equipment shall be to a recognised national or international quality and performance standard. All systems should be fail safe and programmable devices should have an appropriate safety integrity level (SIL) rating as determined by risk assessment, advice is available in PD CLC IEC/TR 61508 [20], *Functional safety of electrical / electronic / programmable electronic safety-related systems*.

Atmospheric monitoring equipment shall be installed, used, maintained and tested in line with the manufacturer’s recommendations.

Alarms, along with appropriate warning notices, safety signs and instructions, shall be positioned at strategic locations within the area and at control centres, as determined by the risk assessment. Alarm warnings, for example, flashing lights, audible alarms, etc., shall be clearly visible and shall be duplicated / repeated both outside (i.e. at all access points) and inside the workspace. Appropriate, clear and legible warning signs shall be provided (for example, ‘*Do not enter unless monitoring system shows no fault/safe to enter condition’*, ‘*Evacuate the area in the event of gas alarm’*, etc.), located appropriately and, where of potential benefit, repeated in several locations.

Alarm levels shall be set to allow action to be taken in the event of a release of product before danger is created. This will provide an early warning system, but not such that it creates false alarms; thus allowing time for personnel to evacuate the area before hazardous conditions are reached, for example, based on the flammability range and / or workplace exposure limits.

The atmospheric monitoring equipment status shall be checked for safe operation before entry to the relevant area and during occupancy.

Personnel competence development programmes shall include clear details of the atmospheric monitoring equipment and the actions to take to ensure safe entry to confined spaces, maintenance / checking of the system, verifying status, how to respond to alarms, etc.

The atmospheric monitoring equipment may interface with other systems, for example, the emergency shut-down system, mechanical ventilation systems (refer to Appendix 2), etc., allowing automatic operation. What 'automatic operation' precisely means will depend upon the details of the overall control system(s). An integrated control system should be provided, in line with the Risk Assessment. Whilst it is not possible to provide definitive advice that will apply to all installations and circumstances, the following points should be considered in relation to system control integration:

- will the ventilation automatically trigger in the event of a gas detection alarm?
- is there value in installing multi-stage alarms (different percentage concentration detection) to trigger corresponding multi-speed ventilation fans?
- what fan overrun time should be applied, before an alarm resets?
- what self-diagnostics should the system(s) include?
- is auto detection of ventilation failure (flow switches, differential pressure switches, etc.) desirable for the system?
- should the ventilation system operate even when personnel entry is not required, or for a specific period in advance of entry?
- will the alarm activate in the event of gas detection or ventilation fault / failure?
- can or should inter-locking of access doors be included in the system functionality, to prevent entry during an alarm? In all circumstances, egress shall not be obstructed.
- can remote automatic shut-down of the system be included, in the event of alarm?
- is an uninterruptable power supply (UPS) desirable for whole or part of the system, for example, critical control functionality or lock-outs?
- auto detection of ventilation failure (flow switches, differential pressure switches, motor overload or underload, etc.)?
- connection to the premises fire alarms, taking account of the desirability of disabling the ventilation fans in the event of fire?
- the management of system outages, for example, for planned maintenance?
- the use of data-logging functions, for example, to regularly review for non-alarm gas events in case these show trends or the need for investigation or intervention?
- possible use of ancillary systems (for example, refrigeration fans)?

The gas detection / ventilation system(s) shall be subject to a formally planned inspection and maintenance regime, that includes calibration, periodic functional and end-to-end testing, (often known as 'bump testing'), alarm and interlock checks, lamp (bulb) checks for visual alarms or annunciators and the periodic replacement of critical or wearing components, etc.

Records of maintenance, testing and calibration shall be kept.

For additional information on atmospheric monitoring refer to:

- HSE RR 973 [9], *Review of alarm settings for toxic gas and oxygen detectors*.
- HSE HSG 173 [12], *Monitoring strategies for toxic substances.*
- The CoGDEM guide to gas detection [47].

For information on gas detectors in potentially explosive atmospheres, refer to BS EN 60079 [19], *Explosive atmospheres*, Part 29-2: *Gas detectors. Selection, installation, use and maintenance of detectors for flammable gases and oxygen.*

WORK IN CONFINED SPACES

Any workplace designated as a 'confined space' following Risk Assessment shall then be assessed in line with the requirements of the *Confined Spaces Regulations* [3] and be subject to specific controls before and during entry. In most cases the assessment will include consideration of:

- the task(s);
- the working environment;
- working materials and tools;
- the competence and suitability of those carrying out the task;
- arrangements for emergency situations.

Some confined spaces are fairly easy to identify, for example, enclosures with limited openings:

- cellars in beverage dispense outlets;
- lifts, elevators as well as lift shafts;
- storage tanks;
- silos;
- reaction vessels;
- enclosed drains;
- sewers.

Others may be less obvious, but can be equally dangerous, for example:

- open-topped chambers;
- vats;
- combustion chambers in furnaces, etc.;
- ductwork;
- unventilated or poorly ventilated rooms;
- any area where there is significant inventory of gases;
- spaces not designed for continuous worker occupancy.

It is not possible to provide a comprehensive list of confined spaces. Some places may become confined spaces when work is carried out, or during their construction, fabrication or subsequent modification. However, it is important to note that even a large open topped vessel may represent a hazard, i.e. if it has contained an inert gas denser than air it may contain an unsafe atmosphere below the level of the vessel wall that will not be removed by natural ventilation, for example, tank bunds, dry ice containers, etc. Care should be taken not to lean into such spaces, i.e. an action short of entry, but where there is still exposure to the hazard.

Specific controls that may be employed before entering a confined space include:

- analysis of the space for the presence of a gas such as oxygen, flammable or toxic gases, for example, using atmospheric monitoring equipment. Refer to Appendix 3;

- purging of the space with air. In the specific case of flammable gases, an inert gas purge may be used first to prevent any explosion risk and then a subsequent purge with air;

- the use of a work permit system, which generally should be used for all confined space entries;

  Information on work permit systems can be obtained from HSE HSG 250 [13] and EIGA 40 [22].

- the isolation, disconnection, sealing and spading of pipework;

  NOTE: Rendering pipework pressure gas-tight is significantly different from pipe 'spading'.

- the use of interlock control devices;

- the use of additional and specialist PPE, for example, breathing apparatus. Refer to Section 10.5;

- emergency planning. Refer to Section 11;

Entry in to confined spaces is a legislated activity, specifically covered by the *Confined Spaces Regulations* [3]. HSE provide further information on working in confined spaces within:

- HSE L101 [17], *Safe work in confined spaces. Confined Space Regulations 1997. Approved Code of Practice and guidance*;

- HSE INDG 258 [14], *Confined spaces. A brief guide to working safely*.

MOVEMENT OF GASES IN LIFTS

Most lifts will be a confined space. Gases should not generally be placed in or moved in a lift.

This activity shall only take place following a suitable and sufficient risk assessment. Before a lift is considered, all alternative means to moving gas containers shall be taken into account. Alternatives may include:

- designing or selecting an appropriate building for gas storage and use, eliminating the need to move gas containers within the building;

- have the location where the gases are to be used located on the ground floor, at the same level where they are stored;

- installation of an appropriate gas supply and distribution system to pipe the gas to the place of use, refer to BCGA CP 4 [29] and BCGA CP 5 [30];

- the use of external (rather than internal) lifts (elevators), which are open to atmosphere;

- the use of outdoor cranes and hoists.

Before movement in a lift takes place a detailed risk assessment in accordance with the *Management of Health and Safety at Work Regulations* [4] and the *Confined Spaces Regulations* [3] shall be carried out and suitable controls with safe procedures established. All lifts will become classified as a confined space when hazardous substances are introduced. The release of any gas and the subsequent change in the atmosphere will produce danger.

The risk assessment shall take into account the following:

- the suitability of the lift, for example, weight capacity, compatibility with properties of the gases, for example, the extreme cold generated by cryogenic liquids;

- management control of the operation. Use of key control, access management, supervision (including of personnel stationed at each floor and destination point), communications, local temporary signage, etc.;

- choosing an appropriate time to use a lift, for example, out of normal working hours, but where sufficient supervision is available;

- ventilation and extraction; for example, that any released gases are able to vent so as not to cause danger. Consider to where a released gas will vent;

- avoidance of people accompanying the gases and others entering the lift through suitable management controls;

- the quantity of gases being moved;

- the stability and security of the gas containers;

- presence of items associated with the gas containers, for example, cylinder trollies, liquid withdrawal devices, regulators and hoses, use of blanking caps and plugs, etc.;

- atmospheric monitoring and testing of the lift or any area where gases may accumulate, before, during and after the movement. This includes the lift shaft and any connected services;

- post movement actions, for example, the management of any spillage or leakage and preventing use of the lift until there is a safe atmosphere (inside the lift);

- a comprehensive emergency plan taking account of all foreseeable scenarios.

British Compressed Gases Association

www.bcga.co.uk

APPENDIX 8 INSTALLATION PERMITTING GUIDANCE FOR HYDROGEN AND FUEL CELL RY STATIONARY APPLICATIONS

HSE

Health and Safety Executive

Installation permitting guidance for hydrogen and fuel cell ry stationary applications: UK version

Prepared by Health and Safety Laboratory for the Health and Safety Executive 2009

RR715

Research Report

Health and Safety Executive

Installation permitting guidance for hydrogen and fuel cell stationary applications: UK version

The HYPER project, a specific targeted research project (STREP) funded by the European Commission under the Sixth Framework Programme, developed an Installation Permitting Guide (IPG) for hydrogen and fuel cell stationary applications. The IPG was developed in response to the growing need for guidance to foster the use and facilitate installation of these systems in Europe. This document presents a modified version of the IPG specifically intended for the UK market. For example reference is made to UK national regulations, standards and practices when appropriate, as opposed to European ones.

The IPG applies to stationary systems fuelled by hydrogen, incorporating fuel cell devices with net electrical output of up to 10 kWel and with total power outputs of the order of 50 kW (combined heat + electrical) suitable for small back up power supplies, residential heating, combined heat-power (CHP) and small storage systems. Many of the guidelines appropriate for these small systems will also apply to systems up to 100 kWel, which will serve small communities or groups of households. The document is not a standard, but is a compendium of useful information for a variety of users with a role in installing these systems, including design engineers, manufacturers, architects, installers, operators/maintenance workers and regulators.

Update November 2023
This report was published in 2009. Some of the information in the introductory section 2.3 relating to hydrogen viscosity and the potential for possible leaks from hydrogen systems has been superseded by the information in Research Report RR1169 (2022) ‘Hydrogen in the natural gas distribution network: Preliminary analysis of gas release and dispersion behaviour’. The superseded information does not affect the scientific information in the rest of this report. It has not affected any evidence assessment by HSE on using hydrogen including for heating. The Government's Hydrogen Strategy was published in August 2021.

Technical specialists may wish to note the details of the superseded information in introductory section 2.3.This is incorrect information on page 6. Firstly, in table 1, the gas viscosities should state (in g/cm-sec x 10-5 at normal temperature and pressure) 0.110, not 0.651 for methane, and 0.088, not 0.083 for hydrogen. Secondly the following technical statement is not correct: “Hydrogen gas has a very low viscosity and so it is very difficult to prevent hydrogen systems from developing leaks. Pipe work that was ‘leak tight’ when pressure-tested with nitrogen will often be found to leak profusely when used on hydrogen duty.” This incorrect statement is superseded by the information in RR1169 (2022).

This report and the work it describes were funded by the Health and Safety Executive (HSE). Its contents, including any opinions and/or conclusions expressed, are those of the authors alone and do not necessarily reflect HSE policy.

D K Pritchard, M Royle & D Willoughby
Health and Safety Laboratory
Harpur Hill
Buxton
Derbyshire
SK17 9JN

HSE Books

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EXECUTIVE SUMMARY

Objectives

The HYPER project started on 1 November 2006 and ended in February 2009. The work programme of the HYPER project was structured around the development of an installation permitting guide (IPG) which includes:

- An assessment of current knowledge on installation requirements of small stationary hydrogen and fuel cell systems;
- Detailed case studies of representative installations;
- Modelling and experimental risk evaluation studies to investigate fire and explosion phenomena.

The IPG was developed in response to the growing need for guidance to facilitate small hydrogen and fuel cell stationary installations in Europe. This report is a revised version of the IPG intended for the UK market, reference being made to UK national regulations and standards as opposed to European as appropriate.

This document is not a standard, but is a compendium of useful information for a variety of users with a role in installing these systems, including:

- Design engineers;
- Manufacturers;
- Architects;
- Installers;
- Operators/Maintenance workers;
- Regulators.

The document is organised as follows:

- Introduction and Scope (Chapter 1);
- Introduction to fuel cell systems and their associated hazards (Chapter 2);
- General and Higher Level Requirements (Chapter 3);
- System Specific and Siting Considerations (Chapter 4);
- Permitting Route (Chapter 5);
- Appendices.

The IPG applies to stationary systems fuelled by hydrogen, incorporating fuel cell devices with net electrical output of up to 10kWel and with total power outputs of the order of 50kW (combined heat + electrical) suitable for small back up power supplies, residential heating, combined heat-power (CHP), and small storage systems. Many of the guidelines appropriate for these small systems will also apply to systems up to 100 kWel, which will serve small communities or groups of households.

Recommendations

The complexity of the permitting route required for a particular installation should be proportionate to the scale, intended use and location of the installation. Residential installations are likely to require a simpler permitting route than a commercial or industrial installation. It is recommended, however, that any permitting route should comprise at least the following five steps.

Step 1. Undertake a risk assessment to identify the hazards and the measures to be implemented to eliminate or mitigate their effects. The principal hazards will be fire and explosion ones, but other hazards, e.g. electrical, pressure and weather (for outdoor locations) related, need to be taken into account. Hazards that are likely to arise during the lifetime of the installation also need to be considered. This would include those hazards associated with installation of the equipment, start up and shutdown of the equipment, delivery of consumables (eg gas cylinders) and maintenance and repair. For domestic installations a fairly basic risk assessment will be sufficient and in some cases one may not be required at all, e.g. for an integrated CHP system. In these cases it is proposed that all that is required is that the equipment is installed according to the manufacturer's instructions, as in drawing up these instructions the manufacturer will have undertaken a risk assessment.

Step 2. Check the equipment used in the installation complies with the essential health and safety requirements of all applicable EU Directives. For fuel cells and associated equipment the applicable Directives will include the ATEX Directives, Pressure Equipment Directive, Machinery Directive, Gas Appliances Directive, Low Voltage Directive and Electromagnetic Compatibility Directive.

Step 3. Check the installation meets national legislation dealing with planning approval, building regulations and fire regulations. Installations that can export surplus electricity generated back to the distribution grid will also need to meet any regulations for interconnectivity of supplies.

Step 4. The equipment is installed and maintained by a competent person.

Step 5. Inform the local fire brigade of the location and type of installation and especially for the more complex installations give the opportunity to visit and familiarise themselves with the installation. Of particular interest would be the location and quantity of any hydrogen stored on the site. For domestic installations it would also be prudent to inform the property insurers of the installation.

CONTENTS

1 INTRODUCTION AND SCOPE

1.1 HOW THE DOCUMENT WAS PRODUCED

The HYPER project started on 1 November 2006 and ended in February 2009. The work programme of the HYPER project was structured around the development of an installation permitting guide (IPG)[1] which includes:

- An assessment of current knowledge on installation requirements of small stationary hydrogen and fuel cell systems;
- Detailed case studies of representative installations;
- Modelling and experimental risk evaluation studies to investigate fire and explosion phenomena.

This specific targeted research project (STREP) was funded by the European Commission under the Sixth Framework Programme and contributes to the Implementation of the Thematic Priority 'Sustainable Energy Systems', Contract No 039028.

The IPG was developed in response to the growing need for guidance to facilitate small hydrogen and fuel cell stationary installations in Europe. This report is a revised version of the IPG intended for the UK market, reference being made to UK national regulations and standards as opposed to European as appropriate.

1.2 HOW TO USE THE DOCUMENT

This document is not a standard, but is a compendium of useful information for a variety of users with a role in installing these systems, including:

- Design engineers;
- Manufacturers;
- Architects;
- Installers;
- Operators/Maintenance workers;
- Regulators.

The document is organised as follows:

- Introduction and Scope (Chapter 1);
- Introduction to fuel cell systems and their associated hazards (Chapter 2);
- General and Higher Level Requirements (Chapter 3);
- System Specific and Siting Considerations (Chapter 4);
- Permitting Route (Chapter 5);

- Appendices.

Although it is envisaged that the information may be of interest to all user groups, an effort has been made to organise information for ease of use by each user group, particularly in Chapter 3. Chapter 4 contains additional information relating to specific systems as well as details on siting considerations.

The information in this document provides guidance on some safety aspects of the equipment. This is not a substitute for meeting applicable standards, codes and regulations. Relevant standards, codes and regulations are referenced, where available, in the text and Appendix 1 gives a listing of current codes and standards. As many standards and codes are currently in development or only recently adopted, and system designs have yet to be finalised by many manufacturers, it may be some time before we can reasonably expect equipment certification to these codes and standards. Certification, including CE marking, is not required for demonstration prototypes. It is hoped that the guidance provided in this document can facilitate demonstration and early market installations. A list of abbreviations used in this document is available in Appendix 6. References are provided in Appendix 7.

1.3 SCOPE

The IPG provides a structured analysis of known documents relevant for permitting hydrogen and fuel cell systems in the UK, and documents best practice for the installation of different generic types of hydrogen and fuel cell systems. It also provides guidance on issues not properly dealt with in existing documents, and, therefore, provides the basis for harmonised permitting guidance. The IPG takes account of the already established permitting requirements for natural gas appliances.

The IPG applies to stationary systems fuelled by hydrogen, incorporating fuel cell devices with net electrical output of up to 10kWel (small according to IEC 62282.3.3:2007[2]), and with total power outputs of the order of 50kW (combined heat + electrical) suitable for small back up power supplies, residential heating, combined heat-power (CHP), and small storage systems.

Many of the guidelines appropriate for these small systems will also apply to systems up to 100 kWel which will serve small communities or groups of households.

2 BACKGROUND

2.1 FUEL CELL SYSTEMS

2.1.1 Types of fuel cell

A fuel cell is an electrochemical device that combines hydrogen and oxygen to produce electricity, heat and water. The hydrogen may be produced as a by-product of a chemical process, extracted from any hydrocarbon fuel such as natural gas, gasoline, diesel, or methanol via a fuel reformer, or by electrolysis of water. The oxygen is usually obtained from the ambient air around the fuel cell. In some cases where hydrogen is produced by electrolysis, the oxygen co-produced may be used in the fuel cell.

Fuel cells can be loosely grouped into those with acidic electrolytes, those where the electrolyte is alkaline, and cells that operate at very high temperatures.

Successful examples of acidic electrolyte fuel cells are the proton exchange membrane or polymer electrolyte membrane fuel cells (PEMFCs), that use a solid polymer as an electrolyte and porous carbon electrodes containing a platinum catalyst, and the phosphoric acid fuel cells (PAFCs) that use liquid phosphoric acid as an electrolyte (the acid is contained in a Teflon-bonded silicon carbide matrix) and porous carbon electrodes containing a platinum catalyst. PEMFCs are generally designed to be operated at lower temperatures, although some may operate at around 80°C, while PAFCs typically operate at temperatures between 150°C to 200° C.

Alkaline electrolyte fuel cells (AFCs) use an aqueous solution of potassium hydroxide as the electrolyte and can use a variety of non-precious metals as a catalyst at the anode and cathode. Most AFCs operate at temperatures of between 100°C and 250°C, but new designs operate at lower temperatures of between 20°C to 70°C.

High temperature fuel cells include molten carbonate fuel cells (MCFCs) and solid oxide fuel cells (SOFCs). MCFCs use an electrolyte composed of a molten carbonate salt mixture suspended in a porous, chemically inert ceramic lithium aluminium oxide and operate at 650°C and above. SOFCs use a hard, non-porous ceramic as the electrolyte and operate usually at around 1,000°C. Ongoing research is aimed at reducing this operating temperature down to 550-700°C.

2.1.2 Components of a fuel cell system

All fuel cells work broadly on the same principle:

- Hydrogen or a hydrogen-rich fuel is fed to the anode, where a catalyst separates hydrogen's negatively charged electrons from positively charged ions (protons).

- At the cathode, oxygen combines with electrons, and in some cases with species such as protons or water, resulting in water or hydroxide ions respectively.

- For polymer electrolyte membrane and phosphoric acid fuel cells, protons move through the electrolyte to the cathode to combine with oxygen and electrons to generate water.

- The electrons from the anode side of the cell cannot pass through the membrane to the positively charged cathode so they must travel around it via an electric circuit to reach the other side of the cell. This movement of electrons is an electric current.

The design of fuel cell systems can vary significantly depending on the fuel cell type and application. However most fuel cell systems consist of four basic components:

1. A set or stack of individual cells consisting of an electrolyte sandwiched between two thin electrodes.

2. A fuel cell processor/reformer that converts the hydrogen-rich fuel into a form usable by the fuel cell, an electrolyser or a hydrogen storage system (tank or transportable cylinders). Most fuel cell systems use pure hydrogen or hydrogen-rich fuels, such as methanol, gasoline, methane, diesel or gasified coal, to produce electricity. These fuels are passed through onboard internal reformers within the fuel cell itself, or though external reformers that extract the hydrogen from the fuel.

3. Power-conditioning equipment that converts the direct current produced by the fuel cell into alternating current.

4. A number of subsystems to manage air, water, thermal energy and power.

Although all fuel cell power plants contain these components, the assembly of these components into the actual equipment is very important.

In addition, a heat recovery system is typically used in high-temperature fuel cell systems that are used for stationary applications where the excess energy in the form of heat can be used to produce steam or hot water or converted to electricity.

2.2 HAZARDS ASSOCIATED WITH FUEL CELL INSTALLATION AND OPERATION

2.2.1 Hazards of fuel cells other than hydrogen

Many fuel cells use hydrogen produced by the reforming of hydrocarbon fuels; other high temperature fuel cells are able to utilise suitable hydrocarbons directly. The processing and/or use of these hydrocarbon fuels will produce carbon dioxide. Appropriate measures, such as containment and ventilation, should be taken to ensure that any carbon dioxide effluent stream is effectively discharged and does not produce an asphyxiation risk[3].

Natural gas (methane) is lighter than air and will tend to diffuse upwards, but at a much slower rate than hydrogen. The explosion limits for natural gas (5-15% v/v) are also much narrower than hydrogen. The characteristics of both fuels should be considered for any dual fuel systems. The pipe work and equipment used to supply natural gas should also be suitable and designed to an appropriate standard[4].

Liquefied petroleum gas (LPG) is considerably heavier than air, especially when cold, for example when taken directly from a liquid storage vessel. In the event of a leak, LPG vapour will usually percolate downwards and may accumulate on the floor or in low-lying sumps, rapidly producing a flammable atmosphere. Mixtures containing 2-10% v/v LPG in air will readily ignite and explode[5]. The significant differences in the buoyancy and dispersion characteristics of the two fuels should be carefully considered in systems where LPG and hydrogen may both be present. The pipe work and equipment used to store and supply LPG fuel should also be suitable and be designed to an appropriate standard[4].

Methanol can be used directly by some types of fuel cell. This fuel has some hazards that demand particular attention. In addition to being a highly flammable liquid, methanol is also toxic by inhalation, ingestion and notably, by skin absorption[6]. Appropriate precautions such as containment and ventilation should be taken to prevent spillages and the accumulation of hazardous methanol/air mixtures whenever it is used.

Compared to the hazards associated with more conventional equivalents to fuel cells e.g. natural gas boilers and batteries, some different hazards have to be taken into account, including not only the fuel cell but also the means of fuel production, storage and transportation.

2.2.2 Fire and explosion hazards

The estimation of hazards and hazard levels is essential to the consideration of accidental consequences, e.g. overpressures, thermal radiation, the throw of debris or missiles, and the damage level or the vulnerability of the receiving objects. In chemical fires/explosions that are usually exothermal oxidation reactions, a great proportion of the combustion energy is carried by the developing blast wave uniformly distributed in all directions.

Many flammable gases are widely in use today, such as methane, propane etc. Without appropriate measures being taken, a gas release and subsequent fire and explosion can occur. Hydrogen has some significantly different properties from these more commonly used gases which need to be fully appreciated to achieve comparable levels of safety.

Hydrogen for use in fuel cells may be stored in a number of ways:

- As a compressed gas - normally in conventional gas cylinders at a pressure of 200bar, but this pressure may be increased in specialist applications to increase energy storage density.
- As a cryogenic liquid - hydrogen is stored as a liquid below -250 ^{o}C therefore, consideration should be given to cold burns, condensation of oxygen-enriched atmospheres, and the way in which a liquid spill may develop into a flammable cloud. It should be appreciated that the vapour produced by a liquid spill will not initially be buoyant due to its low temperature.
- Complex hydrides are also used as a hydrogen storage medium, generally based on sodium aluminium hydrides or similar materials. These materials are flammable solids and can react violently with water to produce hydrogen and a corrosive aqueous solution. Hydride storage systems can be suitably designed to avoid these hazards.

2.3 PROPERTIES AND CHARACTERISTICS OF HYDROGEN

Hydrogen is a colourless, odourless gas that is lighter than air. The use of odorants to detect leaks[7] is being investigated, however, all the odorant chemicals so far considered have been rejected due to concerns regarding their potential to ‘poison’ the fuel cell membrane catalysts. Furthermore, they may have limited effectiveness for small leaks, as the odorant molecules will inevitably be much larger than the hydrogen molecules.

Hydrogen has many characteristics which are significantly different from conventional fuels, and which it is important to take into account when designing and installing a fuel cell system.

A comparison of the characteristics of hydrogen against two other widely used fuels, natural gas and LPG is given in Table 1.

Table 1 - Characteristics of hydrogen, dry natural gas and gaseous propane

Property	Dry natural gas (methane)	LPG (propane)	Hydrogen
Density (Kg/m^3) *	0.65	1.88	0.090
Diffusion coefficient in air (cm^2/s) *	0.16	0.12	0.61
Viscosity (g/cm-s x 10^{-5}) *	0.651	0.819	0.083
Ignition energy in air (mJ)	0.29	0.26	0.02
Ignition limits in air (vol %)	5.3 – 15.0	2.1 – 9.5	4.0 – 75.0
Auto ignition temperature (C)	540	487	585
Specific heat at constant pressure (J/gK)	2.22	1.56	14.89
Flame temperature in air (C)	1875	1925	2045
Quenching gap (mm) *	2	2	0.6
Thermal energy radiated from flame to surroundings (%)	10-33	10 - 50	5-10
Detonability limits (vol % in air)	6.3-13.5	3.1 – 7.0	13-65
Maximum burning velocity (m/s)	0.43	0.47	2.6

* at normal temperature and pressure – 1 atmosphere and 20^{o}C

2.3.1 Propensity to leak

2.3.1.1 Low viscosity

Hydrogen gas has a very low viscosity and so it is very difficult to prevent hydrogen systems from developing leaks. Pipe work that was 'leak tight' when pressure-tested with nitrogen will often be found to leak profusely when used on hydrogen duty.

Hydrogen leakage through welds, flanges, seals, gaskets, etc is an important consideration and an important design and operational issue for hydrogen systems.

The use of suitable sealing interfaces and appropriate components within a hydrogen system, however, will significantly reduce the likelihood of this occurring if fitted by a competent person. For high-pressure storage systems, hydrogen would leak nearly three times faster than natural gas and over five times faster than propane. However the low energy density of hydrogen means that it produces substantially lower energy leakage rates.

2.3.1.2 Extremely high diffusivity

Hydrogen is very much lighter than air and is also very diffusive. Thus, unlike heavier gaseous fuels, if a hydrogen leak occurs in an open or well-ventilated area its diffusivity and buoyancy will help to reduce the likelihood of a flammable mixture forming in the vicinity of the leak.

However, as with other gases when leaks occur within poorly ventilated or enclosed areas, the concentration may rapidly reach dangerous levels. Due to its lightness, hydrogen will concentrate in elevated regions of an enclosed space, whereas other gases, dependent upon their relative mass, will concentrate at ground level (LPG) or at elevation (CNG). If unprotected electrical equipment or other sources of ignition are present, the risk from explosion could be considerable.

As hydrogen diffuses more rapidly through air and through solid materials compared to other fuel gases such as methane or propane, it will usually disperse more rapidly if released, although buoyancy effects are less significant for high momentum releases from high-pressure hydrogen systems. When harnessed through intelligent equipment design and layout, this buoyancy and hydrogen's rapid dispersion rate can become a significant safety asset.

2.3.1.3 High buoyancy

The buoyancy of hydrogen can also be used to manage the risk normally associated with fuel handling by segregating the hydrogen from foreseeable sources of ignition using internal partitions and bulkheads and differential pressurisation. This can also be done by locating all potential sources of ignition well below the level of the equipment from which hydrogen may leak and accumulate, and ensuring adequate ventilation and safe discharge of the exhaust.

2.3.2 Propensity to cause embrittlement

Hydrogen can cause embrittlement of high strength steels, titanium alloys and aluminium alloys with cracking and catastrophic failure of the metals at stress below the yield stress. This is most commonly related to the carbon content of metallic alloys. Pure, unalloyed aluminium, however, is highly resistant to embrittlement. The industry standard for components in hydrogen service is grade 316 stainless steel. Cupro-nickel is also suitable for hydrogen service and copper can be used for low-pressure applications.

2.3.3 Propensity to ignite

2.3.3.1 Wide flammability range

Hydrogen readily forms an explosive mixture with air. The range of hydrogen/air mixtures that will explode is wide. Mixtures containing from as little as 4% v/v hydrogen, which is the lower explosive limit (LEL), up to as much as 75% v/v, which is the upper explosive limit (UEL), may propagate a flame. The wide range of flammability of hydrogen-air mixtures compared to propane and methane-air mixtures is, in principle, a disadvantage. There are, however, only minor differences between the LEL of hydrogen and that of methane or propane. The LEL of hydrogen is considered by many experts to have a greater significance in hazard ranking than the width of the fuel's flammable range. Furthermore, in the case of low momentum releases, the dispersion characteristics of hydrogen will make it less likely that a flammable mixture will form.

2.3.3.2 Very low ignition energy

The energy necessary to initiate a hydrogen/air explosion is very small. The ignition energy for a 2:1 hydrogen/oxygen mixture is only about 0.02 mJ. This is less than one tenth that of other fuels such as methane, LPG or petrol. Even very small sparks, such as those produced by wearing certain types of clothing, are capable of igniting hydrogen/air mixtures and causing an explosion.

2.3.3.3 *Spontaneous ignition*

Hydrogen has the possibility to spontaneously ignite on sudden release from pressurised containers.

2.3.4 Consequences of a fire / explosion

2.3.4.1 *Invisible flame*

Hydrogen burns with an invisible flame making it difficult to detect a hydrogen fire. This apparent low emissivity of hydrogen flames (total heat flux radiated) may reduce the heat transfer by radiation to objects near the flame, thus reducing the risks of secondary ignition and burns. However, such effects have not been fully quantified and further work is needed in this area.

2.3.4.2 *Rapid burning rate*

The maximum burning velocity of a hydrogen-air mixture is about eight times greater than those for natural gas and propane air mixtures. The high burning velocity of hydrogen makes it difficult to confine or arrest hydrogen flames and explosions, particularly in closed environments. In its favour, however, this rapid rate of deflagration means that hydrogen fires transfer less heat to the surroundings than other gaseous fuel fires, thereby reducing the risk of creating secondary fires in neighbouring materials. Another downside of a higher burning velocity of hydrogen is that for a given scenario hydrogen would result in higher explosion pressures and rates of pressure rise than other fuels.

2.3.5 Possibility of detonation

Hydrogen/air mixtures have a greater propensity to detonate than mixtures of air with other more common flammable fuels. Detonations cause much more damage and are far more dangerous than ordinary explosions (deflagrations). However, due to the rapid dispersal characteristics of hydrogen, this is only likely to occur in a confined or congested space.

3 GENERAL AND HIGHER LEVEL REQUIREMENTS

Guidance given in this chapter is of a general nature and is taken from UK legislation and relevant European Community directives. If it is necessary to certify part or all of a fuel cell system using these directives, the full documents should be obtained to assess conformity, unless using a third party for certification. The process of CE certification is briefly described in section 3.1.1.

3.1 DESIGN AND MANUFACTURING REQUIREMENTS

3.1.1 CE certification

CE marking is mandatory in the UK for certain product groups which indicates conformity with the essential health and safety requirements set out in a number of EU directives (e.g. machinery - 2006/42/EC[8], low voltage - 2006/95/EC[9], gas appliances - 90/396/EEC[10], ATEX equipment directive - 94/9/EC[11]).

CE conformity marking concerns the design, manufacture, placing on the market and entry into service of a product. The CE marking must be affixed by the manufacturer or his agent established in the EC.

Depending on the directive concerned, certification is either through self-declaration or through examination and assessment by a notified body.

The manufacturer bears the ultimate responsibility for the conformity of the product. He has to issue a Declaration of Conformity which includes his identity, a list of EU directives he declares compliance with, a list of standards the product complies with, and a legally binding signature.

The basis of the conformity assessment is the Technical Construction File (also referred to in some directives as the technical file or the technical demonstration), which is a compilation of documents containing the product design and security measures that make it safe.

Prototype and demonstration units are not required to have CE marking.

A number of ‘Agreement of Mutual Recognition of Conformity Assessment’ between the EC and third countries (USA, Canada, Australia, Japan, New Zealand, and Israel) allows industries based in those countries to use local certification organisations accredited for the specific directive.

To assist fuel cell components manufacturers, relevant directives and the UK regulations that implement the requirements of the directives are listed in Table 2. A checklist that can be used when seeking EC certification, together with further details on the CE mark, the Technical Construction File and the EC Declaration of Conformity can be found in Appendix 3.

Table 2 - Relevant directives requiring compulsory CE marking

Directive	**Applicable to:**	**Comments**
90/396/EEC - Gas Appliance Directive[10] The Gas Appliances (Safety) Regulations 1995[12]	Appliances burning gaseous fuels used for cooking, heating, hot water production, refrigeration, lighting or washing and having, where applicable, a normal water temperature not exceeding 105^{o}C.	Strictly only applicable to fuel cells where the primary function is heating. However, some principles on general health and safety considerations may still be useful.
94/9/EC - ATEX Equipment Directive[11] Equipment and protective Systems for Use in Potentially Explosive Atmospheres (EPS) Regulations 1996[13]	Equipment (electrical and non-electrical) and protective systems intended for use in potentially explosive atmospheres.	Hazardous area classification must be carried out to assess potential locations and likelihoods of an explosive atmosphere being present to ensure that any equipment cannot act as a source of ignition.
97/23/EC - Pressure Equipment Directive[14] Pressure Equipment Regulations (PER) 1999[15]	This directive applies to the design, manufacture and conformity assessment of pressure equipment with a maximum allowable pressure greater than 0,5 bar above atmospheric pressure for the maximum/minimum temperatures for which the equipment is designed for gases, liquids and vapours.	The certification process by the Pressure Equipment Directive, both certification by the manufacturer and by a notified body, depends on a number of system parameters. These parameters include the hazards posed by the pressurised gas/liquid, the characteristics and dimensions of the equipment and its intended use.

2004/108/CE - Electromagnetic Compatibility Directive[16] The Electromagnetic Compatibility Regulations 2006[17]	Equipment or combinations thereof made commercially available as a single functional unit, intended for the end user and liable to generate electromagnetic disturbance, or the performance of which is liable to be affected by such disturbance.	The manufacturer shall perform an electromagnetic compatibility assessment of the apparatus, on the basis of the relevant phenomena, with a view to meeting the protection requirements set out in the Directive.
2006/95/EC - Low Voltage Directive[9] The Electrical Equipment (Safety) Regulations 1994[18]	Electrical equipment designed for use with a voltage rating of between 50 and 1,000 V for alternating current and between 75 and 1,500 V for direct current.	The electrical equipment should be so designed and manufactured as to ensure protection against the hazards arising from the voltages at which the is used, providing that the equipment is used in applications for which it was made and is adequately maintained.
2006/42/EC - Machinery Directive[8] Supply of Machinery (Safety) Regulations[19,20,21]	Machinery, interchangeable equipment, safety components, lifting accessories, chains, ropes and webbing, removable mechanical transmission devices, partly completed machinery.	The manufacturer or his authorised representative should also ensure that a risk assessment is carried out for the machinery which he wishes to place on the market. For this purpose, he should determine which are the essential health and safety requirements applicable to his machinery and in respect of which he must take measures.

A list of useful codes and standards associated with the various parts of a fuel cell system is given in Appendix 1. A further useful source of information is the BSI published document PD 6686:2006[22]. It discusses the EU and UK legislation intended to minimize the risk of fire and explosion in the process industries and provides a comprehensive guide to the standards, draft standards and other documents that contain technical, practical and organizational information to ensure compliance.

3.1.2 Compliance with EC directives

The manufacturer of a fuel cell and its components, or their authorised representative, must ensure that the relevant EC directives are complied with. Compliance with these directives is mandatory in the UK, however, taking into account the state of the art, demonstration models etc, it may not be possible to meet all the objectives set. In that event, the equipment must, as far as possible, be designed and constructed with the purpose of approaching the objectives detailed in any relevant directive(s). Table 2 gives a list of relevant directives. An outline of what has to be addressed is given in the sections below.

3.1.3 Risk Assessment

The manufacturer of a fuel cell and its components, or their authorised representative, must ensure that a risk assessment is carried out in order to determine the health and safety requirements that apply to the equipment. The equipment must then be designed and constructed taking into account the results of the risk assessment.

There are technical resources available in many EU member states to assist in preparing risk assessments. These include guidance books, videos, training sessions and consultancy services. These can be found using an internet search engine with the key words "risk assessment"

Further guidance on performing a risk assessment is given in Appendix 5.

3.1.4 Protection against mechanical hazards

The Machinery Directive requires the following aspects to be considered:

- Risk of loss of stability;
- Risk of break-up during operation;
- Risks due to falling or ejected objects;
- Risks due to surfaces, edges or angles;
- Risks related to combined equipment;
- Risks related to variations in operating conditions;
- Risks related to moving parts;
- Choice of protection against risks arising from moving parts;
- Risks of uncontrolled movements.

3.1.5 Protection against electrical hazards

The electrical equipment, together with its component parts, should be made in such a way as to ensure that it can be safely and properly assembled and connected. The following should be addressed:

- Protection against hazards arising from the electrical equipment;
- Protection against hazards which may be caused by external influences on the electrical equipment;
- Electricity supply;
- Static electricity;
- Electromagnetic compatibility.

3.1.6 Protection from flammable gas appliance hazards

The Gas Appliances (Safety) Regulations require the possibility of unburned gas release to be considered.

3.1.7 Protection against fire and explosion hazards

The manufacturer should safeguard against risk of fire and explosion.

For fuel cell components for use in potentially explosive atmospheres the Equipment and protective Systems for Use in Potentially Explosive Atmospheres (EPS) Regulations 1996[13] apply.

The ATEX Workplace Directive (99/92/EC)[23], implemented in the UK by the Dangerous Substances and Explosive Atmospheres Regulations (DSEAR) 2002[24], will also apply. Although DSEAR does not specifically require the production of an explosion protection document, as required by the ATEX Workplace Directive, the key requirement of the Regulations is that risks from dangerous substances, e.g. flammable gases, are assessed and controlled.

The DSEAR and EPS Regulations only apply to workplaces and thus would not be applicable to domestic installations.

3.1.8 Protection against pressure related hazards

The Pressure Equipment Regulations (PER) 1999[15] apply to any equipment that could contain pressures in excess of 0.5 bar. The Regulations require the following aspects to be addressed:

- Strength of equipment;
- Provisions to ensure safe handling and operation;
- Means of examination;
- Means of draining and venting;
- Materials for pressure vessels.
- Wear
- Assemblies
- Provisions for filling and discharge
- Protection against exceeding the allowable limits of pressure equipment
- Safety accessories
- Manufacturing procedures
- Marking and labelling
- Operating instructions

At elevated temperatures and pressures, hydrogen attacks mild steels severely, causing decarburisation and embrittlement. This is a serious concern in any situation involving storage or transfer of hydrogen gas under pressure. Proper material selection, e.g. special alloy steels, and technology is required to prevent embrittlement[25].

3.1.9 General health and safety requirements

General health and safety requirements should be addressed with respect to:

- Materials and products;
- External temperatures;
- Errors of fitting;
- Extreme temperatures;
- Noise;
- Vibrations;
- External radiation;
- Emissions of hazardous materials and substances;
- Risk of being trapped in a machine;
- Risk of slipping, tripping or falling;
- Lightning.

3.1.10 Control system requirements

For an appliance equipped with safety and controlling devices, the functioning of the safety devices must not be overruled by the controlling devices (see the BS EN series of standards[26] for control device requirements).

All parts of appliances that are set or adjusted at the stage of manufacture and which should not be manipulated by the user or the installer must be appropriately protected.

Levers and other controlling and setting devices must be clearly marked and give appropriate instructions to prevent any error in handling. Their design must preclude accidental manipulation.

The surface temperature of knobs and levers of appliances must not present a danger to the user.

Other areas that need to be addressed in the design of the control system are:

- Safety and reliability of control systems;
- Control devices;
- Starting;
- Stopping;
- Selection of control or operating modes;
- Failure of the power supply.

3.1.11 Equipment Information, warnings, markings and instructions

The EU Equipment Directives and the UK implementing regulations contain requirements relating to:

- Information and information devices;
- Warning devices;
- Warning of residual risks;
- Marking of equipment;
- Instructions.

3.2 INSTALLATION REQUIREMENTS

Appliances must be correctly installed and regularly serviced in accordance with the manufacturer's instructions.

3.2.1 Installation location

Where practical, particularly for industrial applications, the fuel cell should be located outdoors. Fuel cells for residential applications should be designed, installed, operated and maintained to be safe in typical indoor locations. For non-residential indoor installations, the fuel cell should be located in a well ventilated area in which combustible materials are minimised. In designing the installation consideration should be given as to whether it is necessary to separate the rooms or spaces that enclose the fuel cell installation from other building areas by fire barriers. Use of appropriate protective devices for openings (i.e. doors, shutters, windows, service entries, etc) should also be considered. Voids or openings between the room in which the fuel cell is enclosed and adjacent rooms into which combustion products could pass should be avoided. The shared walls should be gas tight. A check should be made that any automatic fire suppression system installed has been correctly specified for the room or space in which the fuel cell and associated components are located. All installations should comply with building and fire regulations.

For outdoor installations weather protection may be required. Hydrogen storage cylinders and vessels located outdoors need to be protected from extreme temperatures (below –20°C and above 50°C). Permanently installed hydrogen vessels must be provided with substantial supports, constructed of non-combustible material securely anchored to firm foundations of non-combustible material and protected from accidental impact, e.g. from a vehicle. Transportable compressed gas cylinders and vessels shall be secured against accidental dislodgement and protected from accidental impact. The area around hydrogen installations should be kept free of dry vegetation and combustible matter. If weed killers are used, chemicals such as sodium chlorate, which are a potential source of fire hazard, should not be selected for this purpose.

3.2.2 Ventilation

Natural or forced (mechanical) ventilation can be used to prevent the formation of potentially explosive mixtures. Natural ventilation is the preferred method due to its intrinsic reliability. If forced ventilation is used, then the reliability of the system has to be considered.

Appliances which are not fitted with devices such as flues to avoid a dangerous accumulation of unburned gas or combustion products in indoor spaces and rooms should be used only in areas where there is sufficient ventilation to avoid accumulation to dangerous levels.

3.2.3 Pressure systems

Suitable means must be provided for testing and venting pressure equipment. The risk assessment for the installation should cover the pressurising and venting operations. Adequate means must also be provided to permit cleaning, inspection and maintenance in a safe manner of all pressure systems.

3.2.4 Materials selection for installation

Materials used for the installation of hydrogen and fuel cell equipment must be suitable for such application during the scheduled lifetime unless replacement is foreseen.

Where necessary, adequate allowance or protection against corrosion or other chemical attack must be provided, taking due account of the intended and reasonably foreseeable use. Hydrogen gas dissolved in liquids will permeate into adjoining vessel materials. At elevated temperatures and pressures, hydrogen attacks mild steels severely, causing decarburisation and embrittlement. It is, therefore, vital that if hydrogen is stored or handled under pressure compatible materials, e.g. special alloy steels, are used for pipe work, vessels, etc.

3.2.5 Mechanical and thermal hazards

Equipment must be designed and constructed to minimise the risk of injuries from moving parts and hot surfaces. If there are moving parts, appropriate guarding should be provided to prevent accidental contact or ejection of failed components. Hot components need to be insulated or a means provided of preventing accidental contact.

3.2.6 Slipping, tripping or falling hazards

Access to the equipment should be such that there are no slipping, tripping or falling hazards for personnel delivering supplies, e.g. gas cylinders, undertaking maintenance or carrying out repairs to the installation.

Rooms or enclosures containing equipment should be fitted with measures to prevent a person from being accidentally trapped within it or, if that is impossible, with a means of summoning help.

3.2.7 Lightning protection

Outdoor installations may also need protection against lightning strikes. This can be achieved by fitting a system for conducting the resultant electrical charge to earth and also ensuring all equipment is electrically bonded and earthed.

3.2.8 Gas venting

In electrolyser-fed systems, venting facilities for hydrogen and oxygen should be separate and isolated from each other.

3.2.9 Manual handling

Equipment, or each component part thereof, must:

- be capable of being handled and transported safely;
- be packaged or designed so that it can be stored safely and without damage.

During the transportation of the equipment and/or its component parts, there must be no possibility of sudden movements or of hazards due to instability as long as the equipment and/or its component parts are handled in accordance with the instructions.

Where the weight, size or shape of equipment or its various component parts prevents them from being moved by hand, the equipment or each component part must:

- either be fitted with attachments for lifting gear, or
- be designed so that it can be fitted with such attachments, or
- be shaped in such a way that standard lifting gear can easily be attached.

Where equipment or one of its component parts is to be moved by hand, it must:

- either be easily moveable, or
- be equipped for picking up and moving safely.

Special arrangements must be made for the handling of tools and/or machinery parts which, even if lightweight, could be hazardous.

3.3 REGULATORY APPROVAL CONSIDERATIONS

The approval process may depend on whether the installation is in a work environment (industrial) or a residential environment, and the fact that different authorities have responsibility for the industrial and residential premises.

Furthermore, the process may depend on the fuel used. As some fuel cells, especially those providing combined heat and power, operate on natural gas, these fuel cells may qualify under existing regulations and be treated similarly to a gas boiler. For fuel cells operating on other fuels, in particular hydrogen, which is not currently covered by existing regulations as a fuel gas, more time may be required for preparing technical information for the approval and for the review of that information.

3.3.1 Building codes and regulations

Building codes and regulations describe a set of rules which specify an acceptable level of safety for constructed objects, both buildings and non-building structures. Their requirements cover issues such as:

- Design and construction to ensure structural stability of the building and adjoining buildings;
- Fire safety, means of escape, prevention of internal and external fire spread and access and facilites for the fire services;
- Preparation and resistance to moisture;
- Control of toxic substances;
- Resistance to the passage of sound;
- Ventilation;
- Hygiene, safety and provision of sanitary and washing facilites;
- Drainage and waste disposal;
- The use of combustion appliances and fuel storage;
- Protection from falling, collision and impact;
- The conservation of fuel and power;
- Access to and use of the building;
- Safety relating to windows, impact, opening and cleaning;
- Electrical safety.

Some buildings may be exempt from these controls such as temporary buildings, buildings not frequented by people (unless close to a building that is), small detached buildings such as garages, garden storage, sheds and huts, and simple extensions such as porches, covered ways and conservatories. However, it is good practice to have exemption confirmed by the appropriate authority prior to construction.

The Building Regulations 2006[27], as amended, lay down the requirements for England and Wales. Approved Documents have been published[28] for the purpose of providing practical guidance on meeting the requirements of the Regulations. For fuel cell installations the most relevant approved documents are Part A Structure, Part B Fire Safety, Part F Ventilation, Part J Combustion Appliances and Fuel Storage, Part L Conservation of Fuel and Power and Part P Electical Safety. Scotland has its own building regulations, the Building (Scotland) Regulations 2004[29], which are broadly in line with the English and Welsh regulations. Guidance on achieving the requirements of the Regulations are given in a series of Technical Handbooks[30].

3.3.2 Regulations

In the UK, the principal regulations covering hydrogen facilities arise from the national legislation passed to implement the ATEX Directives[11,23] and the Pressure Equipment Directive[14]. Their requirements are not specific to hydrogen and would equally apply to any fuel that is capable of generating a flammable atmosphere, for example natural gas or LPG, or equipment that contains a fuel under pressure. For some components of the installation, for example if the hydrogen is produced in-situ by the reformation of natural gas, the requirements of the Gas Appliances Directive[10] may also be applicable.

ATEX is the name commonly given to the framework for controlling explosive atmospheres arising from gases, vapours, mists or dusts, and the standards of equipment and protective systems used in them. It is based on the requirements of two European Directives. The first is Directive 94/9/EC[11] (also known as ATEX 95 or ATEX Equipment Directive) on the approximation of the laws of member states concerning equipment and protective systems intended for use in potentially explosive atmospheres. The EPS Regulations[13] implements the requirements of the Directive in the UK. Any equipment (electrical or non-electrical) or protective system designed, manufactured or sold for use in potentially explosive situations has to comply with the essential health and safety requirements (EHSR) set out in the Regulations. The second is Directive 99/92/EC[23] (also known as ATEX 137 or the ATEX Workplace Directive) on the minimum requirements for improving the health and safety protection of workers potentially at risk from explosive atmospheres. DSEAR[24] implements the requirements of the ATEX Workplace Directive in the UK. The key requirement of DSEAR is that risks from dangerous substances, e.g. flammable gases, are assessed and controlled.

As the ATEX Directives and thus the DSEAR and the EPS Regulations only apply to the workplace, hydrogen fuel cells installed in domestic premises are outside their scope. Nonetheless the hazard identification process required by DSEAR would serve as a useful model for assessing the safety requirements of domestic installations.

The Pressure Equipment Regulations (PER) 1999[15], implementing the Pressure Equipment Directive (97/23/EC)[14], apply to the design, manufacture and conformity assessment of pressure equipment that is subjected to an internal pressure greater than 0.5 bar above atmospheric pressure. It covers equipment such as pressure vessels, heat exchangers, steam generators, boilers, piping, safety devices and pressure accessories. Thus some of the components of a hydrogen fuel cell installation may fall within the scope of the Directive, although these are usually bought on the market as certified products. Each affected item of pressure equipment has to be assigned into a hazard category according to specific criteria, which then determines the overall essential safety requirements to be met. Depending on the categories, different conformity assessment options are permitted to demonstrate compliance by variants on quality assurance, direct inspection or surveillance of testing by the Notified Body. It is recommended that advice from consultants who specialise in pressure systems be sought in selecting the most appropriate conformity option, as an inappropriate choice can lead to unnecessary delays and costs in demonstrating compliance.

The Gas Appliances Directive[10], implemented in the UK The Gas Appliances (Safety) Regulations 1995[12], applies to appliances burning gaseous fuels used for cooking, heating, hot water production, refrigeration, lighting or washing and having, where applicable, a normal water temperature not exceeding 105°C. It also specifies requirements for certain fittings, including safety, regulating and controlling devices and sub-assemblies. For the purposes of this directive a ‘gaseous fuel’ means any fuel that is in a gaseous state at a temperature of 15°C at a pressure of 1 bar. Though fuel cells do not burn gaseous fuels and should be excluded from the scope of the Directive, guidance issued on what appliances are covered by the Directive includes fuel cells where the primary function is heating. The essential safety requirements of the Directive could also be applied to certain components of the installation, e.g. a reformation unit for generating hydrogen and safety, regulating and control devices.

Hydrogen fuel cell installations would also need to comply with the relevant parts of the Supply of Machinery (Safety) Regulations[19,20,21], the Electrical Equipment (Safety) Regulations 1994[18], the Electromagnetic Compatibility Regulations 2006[17], as well as EU directives and UK legislation covering general health and safety.

Further information on the procedures for demonstrating conformity with EU directives and obtaining CE marking for equipment is given in 3.1 and Appendix 3.

3.4 OPERATIONAL/MAINTENANCE CONSIDERATIONS

3.4.1 Equipment maintenance

Adjustment and maintenance points must be located outside danger zones. It must be possible to carry out adjustment, maintenance, repair, cleaning and servicing operations while equipment is at a standstill. If one or more of the above conditions cannot be satisfied for technical reasons, measures must be taken to ensure that these operations can be carried out safely. In the case of automated equipment and, where necessary, other equipment, a connecting device for mounting diagnostic fault-finding equipment must be provided. Automated equipment components that have to be changed frequently must be capable of being removed and replaced easily and safely. Access to the components must enable these tasks to be carried out with the necessary technical means in accordance with a specified operating method.

3.4.2 Access to operating positions and servicing points

Equipment must be designed and constructed in such a way as to allow access in safety to all areas where intervention is necessary during operation, adjustment and maintenance of the equipment.

3.4.3 Isolation of energy sources

Equipment must be fitted with means to isolate it from all energy sources. Such isolators must be clearly identified. They must be capable of being locked if reconnection could endanger people. Isolators must also be capable of being locked where an operator is unable, from any of the points to which he has access, to check that the energy is still cut off. In the case of equipment capable of being plugged into an electricity supply, removal of the plug is sufficient, provided that the operator can check from any of the points to which he has access that the plug remains removed. After the energy is cut off, it must be possible to dissipate normally any energy remaining or stored in the circuits of the equipment without risk to people. As an exception to the requirement laid down in the previous paragraphs, certain circuits may remain connected to their energy sources in order, for example, to hold parts, to protect information, to light interiors, etc. In this case, special steps must be taken to ensure operator safety.

3.4.4 Operator intervention

Equipment must be so designed, constructed and equipped that the need for operator intervention is limited. If operator intervention cannot be avoided, it must be possible to carry it out easily and safely.

3.4.5 Cleaning of internal parts

The equipment must be designed and constructed in such a way that it is possible to clean internal parts that have contained dangerous substances or preparations without entering them; any necessary unblocking must also be possible from the outside. If it is impossible to avoid entering the equipment, it must be designed and constructed in such a way as to allow cleaning to take place safely.

4 SYSTEM-SPECIFIC AND SITE CONSIDERATIONS

When installing a hydrogen fuel cell system, many safety factors need to be taken into account. While Chapter 3 dealt with the general safety considerations, this chapter deals with system-specific and siting considerations, mainly focused on fire and explosion hazards. When seeking to control the risks associated with using hydrogen, it is important firstly to take all reasonable steps to prevent a loss of containment of hydrogen, secondly to ensure if there is a leak that a flammable atmosphere cannot accumulate, thirdly to control potential ignition sources where flammable atmospheres may accumulate, and finally, to use suitable protection against the fire and explosion hazards. The experimental and modelling programmes in the HYPER project considered scenarios related to the system siting, and the reader is referred to the IPG[1] and the HYPER website[31] for further information on the results of these work programmes.

It should be noted that many of the regulations and standards cited in this chapter would not be applicable or relevant to residential applications. For example, the DSEAR[24] and EPS Regulations[13] only apply to the workplace. Nonetheless it is recommended that the general principles in DSEAR be adopted for identifying hazards and implementing prevention and protection measures for residential applications.

4.1 HYDROGEN GENERATION

4.1.1 Generation options

Hydrogen can be produced at large central production facilities and delivered to the point of use or produced at the point of use, an option that is not available for conventional fuels like natural gas. For small-scale stationary applications, the usual method of delivery from production facilities to site is by single transportable cylinders or manifolded packs of cylinders. An option for the future is via the existing natural gas transmission system. Work is currently in progress to explore the feasibility of using the existing system to transport mixtures of natural gas and hydrogen, with the hydrogen being separated out at the point of use[32].

Methods of on-site production include reforming of natural gas, the gas being supplied by the existing natural gas distribution network and the electrolysis of water. Production units being developed for domestic applications potentially have the capability to generate enough hydrogen to supply a fuel cell (to provide electricity and heating for the home) and re-fuel a hydrogen-powered car. The widespread adoption of on-site production would reduce the need for large-scale hydrogen production facilities and the associated distribution and storage infrastructure.

4.1.2 Standards and guidance

General guidance on the safety of hydrogen systems can be found in the International Standard Organisation's Technical Report ISO/TR 15916:2004[33].

The International Standards Organisation (ISO) has published or is developing standards specifically dealing with hydrogen production systems. ISO 16110-1:2007[34] covers the safety of stationary hydrogen generators intended for indoor or outdoor commercial, industrial and residential applications using fuel-processing technologies. It applies to packaged, self-contained or factory matched generation systems with a capacity of less than 400 m^3/h that convert the input fuel to a hydrogen-rich stream of composition and condition suitable for the type of device using the hydrogen, e.g. a fuel cell. Input streams include one or a combination of the following fuels:

- natural gas and other methane-rich gases derived from biomass or fossil fuel sources;
- fuels derived from oil refining such as petrol, diesel and LPG; alcohols, esters, ethers, aldehydes, ketones and other hydrogen-rich organic compounds; and
- gaseous mixtures containing hydrogen.

Part 2[35] of the standard dealing with procedures to determine the efficiency of these types of generator is under development.

ISO has also published a standard (ISO 22734-1:2008)[36] on hydrogen generators using the water electrolysis process for industrial and commercial applications. It covers the construction, safety and performance requirements of packaged or factory matched generators for both indoor and outdoor use. Hydrogen generators that can also be used to generate electricity such as reversible fuel cells are excluded from the scope of the standard. Part 2[37] of the standard, covering generators for residential applications, is under development with publication expected in May 2010

Hydrogen fuel cells such as PEMFC and AFC usually require a hydrogen supply of high purity, as their performance and operational life can be adversely affected by even trace impurities in the hydrogen supply. This is less so for SOFC. ISO standard ISO 14687:1999[38] deals with product specification for hydrogen fuel. The European Industrial Gases Association (EIGA) document on gaseous hydrogen stations ((IGC Doc 15/06/E)[39] contains some guidance on the operation of purification systems.

4.2 HYDROGEN CONTAINMENT AND PIPING

Measures to prevent the release of dangerous substances should be given the highest priority. The likelihood of a leak occurring can be minimised by using high quality engineering.

Particular attention should be paid to the design, installation, operation and maintenance of hydrogen handling equipment in order to reduce the likelihood and size of any leak[33]. The following points should be taken into account as recommended best practices[3]:

- Ensure that the storage equipment, pipe work and connections conform to an approved standard for hydrogen equipment[39];
- Ensure that maintenance work if effectively controlled and is only carried out by authorised competent people;
- Minimise the frequency with which connections are made and broken;
- For gaseous supply, use appropriate refillable stationary storage in preference to regularly replacing large numbers of separately connected cylinders;
- Use the minimum amount of storage that is practical without disproportionately increasing other hazards, such as those associated with moving gas cylinders;
- Use the minimum length and size of pipe work that is appropriate;
- Use the minimum length of high pressure pipe work, from the pressure source to the high pressure regulator;

- Where possible, use as small a diameter and operating pressure as possible, flow restriction may also be used on high pressure pipe work, in order to minimise mass flow of hydrogen and hence the consequences of any unintended releases (see Figure 1);

- Minimise hydrogen inventories where possible;

- Minimise the number of joints by using continuous lengths of pipe work wherever practicable;

- Where possible use fusion joints (welded or brazed) to join pipe work, flange/threaded connectors may be used where necessary;

- Give due consideration to the risk of fatigue due to vibrations in pipes;

- Ensure that the system is leak tested before use in a manner appropriate to hydrogen systems[39];

- Use a high pressure relief valve downstream from the high pressure regulator that is able to vent into a 'safe' place where hydrogen gas cannot accumulate but can freely disperse;

- Suitable isolation valves, with locking facilities, should be used to enable isolation of sections of pipe work/system for routine maintenance and in emergencies;

- All hydrogen handling equipment and piping shall be identified and appropriately labelled;

- Carry out appropriate inspections of the system at suitable regular intervals and record the results;

- Review the operation and maintenance history at suitable intervals.

When high-pressure storage is used, it should be designed and built to an appropriate design code or standard and located in a secure open-air compound[39]. Measures appropriate to the location should be taken to prevent unauthorised access, vandalism and impact from vehicles.

Cryogenic hydrogen storage installations should be constructed to an appropriate code and located in a suitable open-air position and not within an occupied building[40]. Low temperature storage installations should incorporate suitable measures to prevent oxygen-rich liquid air, a powerful oxidising agent, from condensing on uninsulated surfaces exposed to liquid hydrogen temperatures. To avoid the risk from fire, potentially flammable materials, including asphalt and tarmac, should not be present beneath pipe work where condensation may occur.

Only appropriate pipe work and fittings for the supply of hydrogen should be used[7,39]. Cupro-nickel and stainless steel are preferred materials for high-pressure pipe work whereas copper can be used for lower pressures. All pipe work joints should be brazed or welded where possible. Flanged or screwed joints may be used where necessary. Suppliers should be able to provide information on the operating parameters of pipe work and fitting, and the standards used for their manufacture.

Compression joints are generally not recommended for use on hydrogen systems as it is difficult to achieve and maintain these in a leak-free condition. Where their use is considered essential, such as on small-bore pipe work, they should be suitable for the duty and used in strict accordance with the manufacturer's instructions.

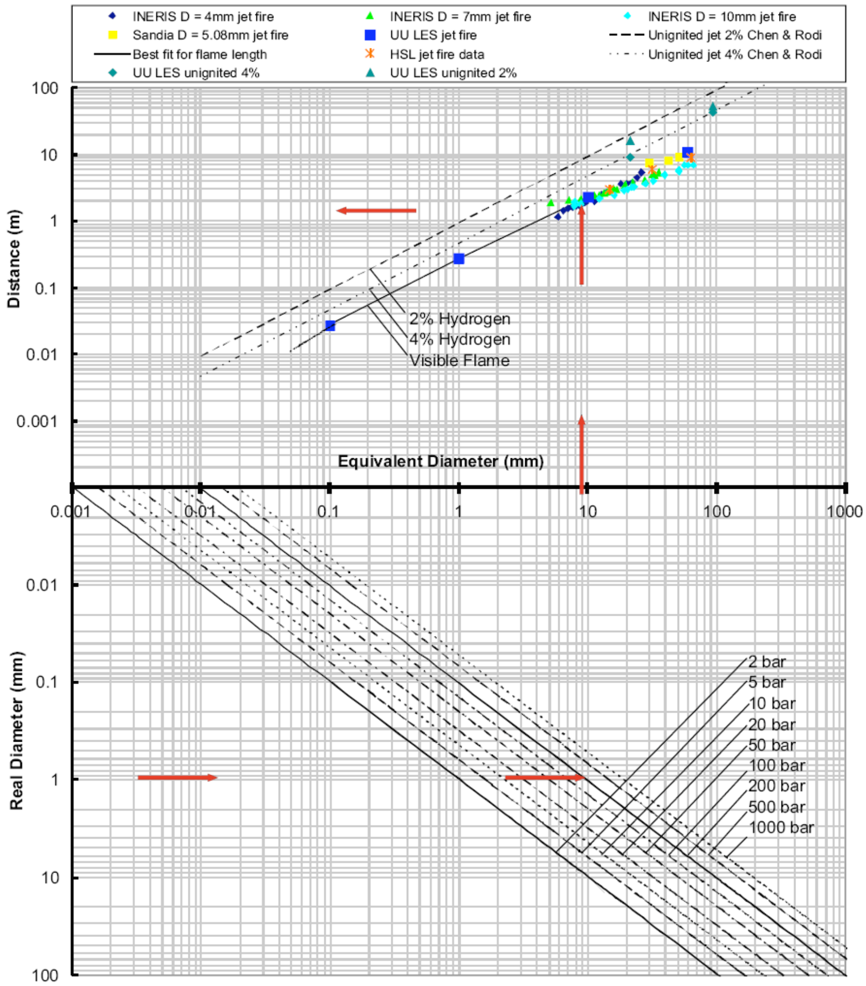


Figure 1 - Nomogram for calculation of flame length of high momentum jet fire by a physical size of leak and pressure in a storage[1]

Particular attention should be given to the design and location joints in the system that may require regular maintenance, or where mechanical joints will be frequently disturbed or made/broken as the likelihood of leaks in these areas is increased. The connection between the cylinder and the manifold is typical of these and should be checked with a suitable detection solution or suitable electronic gas detection device whenever the cylinder is changed[41].

Pipe routing should reflect consideration of factors such as risk from impact damage, formation of flammable mixtures in poorly ventilated areas, heat sources etc. Consequently, where pipe work passes through enclosed ducts, cavity walls etc, there should be no mechanical joints.

Piping should preferably be routed above ground; if underground pipe work is unavoidable, it should be adequately protected against corrosion. The position and route of underground piping should be recorded in the technical documentation to facilitate safe maintenance, inspection or repair. Underground hydrogen pipelines should not be located beneath electrical power lines.

Pipe work should be cleaned before being place into service using a suitable procedure for the type of containment, which provides a level of cleanliness required by the application.

Systems should be suitably purged using an inert gas (i.e. nitrogen) to prevent the existence of a hydrogen/air mixture. Purging can be by sweep purging, evacuation or repeated pressurisation and venting cycles, using appropriately engineering and sited vent and purge connections. Also, consideration should be given to the asphyxiation hazards of using inert gases.

4.3 SITING

Requirements applicable to the siting of stationary fuel cell installations fuelled by hydrogen and of their attendant storage and hydrogen generation systems (the installation) will vary according to whether the installation is located in domestic dwellings, in commercial premises/ buildings, or outside in the open air.

4.3.1 General requirements for both domestic/residential and commercial/industrial installations

The following general requirements apply to all systems whatever their location and should be taken into account in assessing that the risk is acceptable and has been reduced to as low as is reasonably practicable:

- The installation should be placed on firm foundations, capable of supporting it;
- Ensure that any area, enclosure or housing etc into which hydrogen may leak is designed to prevent the gas becoming trapped and is equipped with effective high and low level ventilation openings:
- The installation components, in particularly vent or exhaust outlets, should be sited giving due attention to adjoining doors, windows, outdoor air intakes and other openings into buildings;
- Air intakes shall be located in such a way that the fuel cell is not adversely affected by other exhausts, gases or contaminants;
- Exhaust outlet(s) should not be directed onto walkways or other paths of pedestrian travel
- Security barriers, fences, landscaping and other enclosures should not affect the required flow into or exhaust out of the installation;
- Any vents (from pressure relief valves or bursting joints, etc) should be piped to a safe area and any points of possible leakage should be in an area where any gas cannot accumulate or is freely ventilated. In addition care should be taken that vents do not release hydrogen adjacent to walls or along the ground as this may increase the extent of the flammable cloud or flame;
- Safety/separation distances where a release is foreseeable during normal operation should be determined on a case-by-case basis. Separation distances should be measured horizontally from those points in the system where, in the course of operation, an escape of hydrogen may occur. The most recent version of an appropriate code should be consulted for additional information on the appropriate use of separation distances. In circumstances where it is not practicable to use minimum separation distances, an acceptable situation may be achieved through the use of fire-resistant barriers, fire compartments, fire resistance, room-sealed appliances, appliance compartments, or other hydrogen safety engineering or risk reduction techniques;
- For all indoor locations the installation should comply with all applicable building regulations, particularly as they relate to heating and electrical appliances, fuel storage systems, conservation of fuel and power, protection against pollution, and more

generally to securing reasonable standards of health and safety for people in or about buildings and any others who may be affected by buildings or matter connected with buildings.

- For all indoor fuel cell locations, liquefied and gaseous hydrogen storage should either be located outside in the open air, in an appropriate dedicated unoccupied storage building, in an appropriately ventilated enclosure, or in a purpose designed indoor or underground facility, and should conform to recognised guidance.

4.3.2 Requirements specific to commercial/industrial premises

- The fuel cell and any associated equipment shall be suitably protected against unauthorised access, interference, vandalism or terrorist attack commensurate with the location and installation environment. Any security arrangements shall not compromise the requirement for effective ventilation.

- The fuel cell and associated equipment shall be suitably located to allow service, maintenance and fire department/emergency access and shall be supported, anchored and protected so that they will not be adversely affected by weather conditions (rain, snow, ice, freezing temperatures, wind, seismic events and lightning) or physical damage. Furthermore the placing of any components of the fuel cell system should not adversely affect required building exits, under normal operations or in emergencies.

- If practicable, the installation should be located in a normally unoccupied room built to appropriate fire-resistance standard and within an appropriate fire-resisting and non-combustible enclosure. Congestion, blockages and obstructions should be kept to an absolute minimum in the room as they may enhance flame acceleration in the event of an accident.

- The room in which the fuel cell and associated equipment are located shall provide a minimum of 30 minutes fire-resistance and be fitted with a suitable fire detection and alarm system.

- The installation should not be located in areas that are used or are likely to be used for combustible, flammable or hazardous material storage;

- Any potential sources of ignition, such as non-flameproof electrical light fittings, should be located well below any equipment from which hydrogen may leak and not immediately below horizontal bulkheads or impervious ceilings under which hydrogen may accumulate;

- For workplaces it is a legal requirement, under DSEAR, for the employer to identify fire and explosion hazards, classify areas where explosive atmospheres may exist, evaluate the risks and specify of measures to prevent or, where this is not possible, mitigate the effects of an ignition.

- All equipment (electrical or mechanical) within the identified hazardous zone shall be CE certified. Whenever reasonably practicable, the fuel cell and other hydrogen handling equipment shall be located at the highest level within the enclosure and physically isolated from any electrical equipment that is not ATEX-complaint or other potential sources of ignition.

- Gas-tight compartments, bulkheads and ventilation should as far as possible be used to reduce the likelihood of leaking hydrogen reaching potential ignition sources.

- Unless compliant with the EPS Regulations[13], the installation should be located away from areas where potentially explosive atmospheres may be present;
- The ventilation exhaust or other sources of emission that may contain dangerous substances must be released to a safe place. An appropriate hazardous zone should be identified around any foreseeable release point;
- The following additional factors should be taken into account in assessing that the risk is acceptable and has been reduced to as low as is reasonably practicable: smoking permitted areas; uncontrolled public areas; security barriers; emergency exits.

4.3.3 Emergency planning

It is recommended that an emergency plan should be in place wherever compressed gaseous or cryogenic fluids are produced, handled or stored[42]. This emergency plan should include the following:

- The type of emergency equipment available and its location;
- A brief description of any testing or maintenance programs for the available emergency equipment;
- An indication that hazard identification labeling is provided for each storage area;
- The location of posted emergency procedures;
- A list, including quantities, of compressed gases and cryogenic liquids and their materials safety data sheets (MSDS) or equivalent;
- A facility site plan including the following information:
    - Storage and use areas;
    - Maximum amount of each material stored or used in each area;
    - Range of container sizes;
    - The location of gas and liquid conveying pipes;
    - Locations of emergency isolation and mitigation valves and devices;
    - On and off positions of valves for those that are not self-indicating;
    - A storage and distribution plan that is legible and drawn approximately to scale showing the intended storage arrangement, including the location and dimensions of walkways.
- A list of personnel who are designated and trained to act as a liaison with the emergency services and who are responsible for the following:
    - Aiding the emergency services in pre-emergency planning;
    - Identifying the location of compressed gases and cryogenic fluids stored or used;
    - Accessing MSDS;

- o Knowing the site emergency procedures.

4.4 EXPLOSION PREVENTION AND PROTECTION

For industrial installations DSEAR[24] and the EPS Regulations[13] apply, which require an hierarchical approach to explosion prevention and protection.

DSEAR requires the identification of the explosion hazards and the prevention or protection measures to be employed. The measures taken should be appropriate to the nature of the operation being undertaken, in order of priority and in accordance with the following basic principles:

- § The prevention of the formation of explosive atmospheres, or where the nature of the activity does not allow that;
- § The avoidance of ignition sources where an explosive atmosphere could exist; or
- § If ignition sources cannot be eliminated, the employment of measures to mitigate the effects of an ignition.

This approach to explosion safety, using a range of explosion prevention measures and, if the explosion risk cannot be entirely eliminated, explosion protection measures, is referred to as integrated explosion safety. Guidance on the integrated explosion safety approach can be found in BS EN 1127-1:2007[43], which outlines the basic elements of risk assessment for identifying and assessing hazardous situations. The standard also specifies general design and construction methods to help designers and manufacturers to achieve explosion safety in the design of equipment, protective systems and components.

4.4.1 Prevention of explosive atmospheres

The first line defence in preventing an explosion is to ensure an explosive atmosphere never exists, either as a result of a leak generating an external explosive atmosphere, air ingress forming an explosive atmosphere inside the equipment, or having a process that operates with gas mixtures in the explosive range.

Hydrogen, due to its low viscosity, is particularly prone to leakage from piping, vessels, etc and therefore special attention should be paid to ensuring gas tight connections in any equipment containing hydrogen. The requirements for hydrogen containment and piping are discussed in section 4.2. For processes that operate at sub-atmospheric pressures, leakage of hydrogen will not be an issue but the possibility of air ingress, resulting in the formation of an internal explosive atmosphere, needs to be considered.

Ventilation can be used to prevent small leaks generating an explosive atmosphere by ensuring the escaping gas cannot accumulate to concentrations above the LEL. Ventilation is the air movement leading to replacement of a potentially dangerous atmosphere by fresh air. The following principles should be used to ensure that any foreseeable release of a dangerous substance cannot accumulate to a concentration that affects the safety of people and property:

- Wherever possible locate hydrogen storage/handling equipment outside;
- Estimate the maximum foreseeable release rate;
- Provide adequate high and low ventilation;

- Beware of low ceilings, canopies, covers and roofs;
- Ensure the dilution air is drawn from a safe place;
- Ensure vents and purges discharge to a safe place;
- Use computational fluid dynamics (CFD) for complex ventilation requirements.

It is always best to locate hydrogen storage/handling equipment in the open air, however precautions still need to be taken to ensure that a flammable atmosphere cannot accumulate:

- Avoid the use of low, impervious roofs, canopies or bulkheads;
- Avoid locations below eaves or other overhanging structures;
- Use a suitable, non-combustible security fence rather than a wall;
- Ensure adequate high- and low-level ventilation apertures where a wall around the storage system in unavoidable.

The size of any foreseeable leak into an enclosed or partially enclosed area should be used as the basis for any calculations of the ventilation requirements. The ventilation regime should be sufficient to ensure that the hydrogen concentration is normally maintained below 10% of the LEL (0.4% v/v for hydrogen), with only occasional temporary increases to 25% of the LEL. Some basic equations for a calculating degrees of ventilation are described in BS EN 60079-10:2003[44].

Two main types of ventilation are recognised:

a) Passive or natural ventilation: the flow of air or gases is created by the difference in the pressures or gas densities between the outside and inside of a room or enclosed space.

b) Active or forced (mechanical) ventilation: the flow of air or gas is created by artificial means such as a fan, blower, or other mechanical means that will push or induce an air flow through the system. The artificial ventilation of an area may be either general or local.

Natural ventilation can be provided by permanent openings. The location of the openings shall be designed to provide air movement across the room or enclosed space to prevent the unwanted quantities of hydrogen-air mixtures. Inlet openings for fresh air intakes should be located near the floor in exterior walls (and only in such a way so that they do not reintroduce air previously evacuated from the process area). Outlet openings should be located at the high point of the room in exterior walls or roof. Inlet and outlet openings shall each have a minimum total set area of the room volume. In the ANSI/AIAA Guide for Hydrogen and Hydrogen System[45], a minimum total ventilation area of 0.003 m^2/m^3 of room volume was set for the inlet and outlet openings. Discharge from outlet openings shall be directed or conducted to a safe location. Ventilation openings shall be designed so that they will not become obstructed during normal operation by dust, snow or vegetation in accordance with the expected application. In open air situations, natural ventilation will often be sufficient to ensure dispersal of any explosive gas atmosphere which arises in the area. For outdoor areas, the evaluation of ventilation should normally be based on an assumed minimum wind speed of 0.5 m/s, which will be present virtually continuously (EN 60079-10:2003[44]).

The effect of wind should be borne in mind when deciding vent orientation. Depending on the position of the vents, wind may impede or enhance the ventilation efficiency[46].

If it can be verified, natural ventilation should be permitted to provide all required ventilation and makeup air. If mechanical ventilation is required, the ventilation system shall be interlocked to the hydrogen process equipment to prevent process equipment from working in the absence of ventilation, and therefore shut it down upon loss of ventilation. It shall also be equipped with an audible and visual alarm in order to give a warning in case of failure. The ventilation unit shall be constructed and installed in such a way as to preclude the presence of mechanical and electrical sparking.

The forced ventilation of an area may be either general or local and, for both of these, differing degrees of air movement and replacement can be appropriate. Although forced ventilation is mainly applied inside a room or enclosed space, it can also be applied to situations in the open air to compensate for restricted or impeded natural ventilation due to obstacles. As in the case of natural ventilation, the dilution air used to artificially ventilate the area should enter at low level and be taken from a safe place. The ventilation outflow should be located at the highest point and discharge to a safe place outdoors. Furthermore, the mechanical means used to ventilate the enclosure should be suitable and in particular, the electrical motor(s) should not be located in the potentially contaminated exhaust air stream.

Suitable arrangements should be in place to detect when the ventilation system is failing to provide adequate ventilation. This may be based on the measurement of flow or pressure. This should raise an alarm and safely isolate the electricity supply outside the enclosure and the hydrogen supply outside the building with a normally closed (fail safe) valve. The fuel cell system should shut down safely upon loss of adequate ventilation.

The cooling/air supply fan or compressor present in many fuel cell modules may sometimes be suitable to provide effective ventilation. Where this approach is used, the air must be drawn from a safe place and the direction of the forced airflow must be compatible with the expected movement of any hydrogen release as a result of buoyancy, thermal effects etc.

Where differential pressure is used to prevent the ingress of hydrogen into adjoining compartments, the pressurisation air should drawn from/discharged to a safe place. Also, suitable fail safes should be in place to raise alarms/cause shutdown in the case of any detected loss of ventilation or differential pressure.

The dilution airflow and the number and location of flammable atmosphere detectors should be appropriate in complex systems or congested areas. An appropriate modelling technique should be used in these situations to ensure that pockets of flammable mixture will not accumulate and remain undetected.

In situations where other fuels such as methane, LPG etc are present in addition to hydrogen, the different densities and diffusivities need to be taken into account to ensure that the ventilation arrangements provided are adequate.

Ventilation is not recommended as a prevention measure for large leaks, for example from the catastrophic failure of pipe, as ventilation systems are unlikely to be able disperse large leaks quickly enough to prevent an explosive atmosphere accumulating. If ventilation is used as a prevention measure, then the reliability of the system has to be guaranteed and if the ventilation is only activated when a leak occurs then there must also be a reliable method, e.g. gas detectors, of detecting the leak. Guidance on the selection and location of gas detectors is given in Appendix 4.

There is a higher risk of an explosive atmosphere being present in equipment during commissioning, when items of equipment will initially contain air before assembly, or during maintenance when equipment is opened up for inspection/repair allowing air ingress. For these operations, inerting can be employed to prevent an explosive atmosphere forming. Inerting is a technique by which the equipment is purged with an inert gas, such as nitrogen or carbon dioxide, until the oxygen concentration falls below the level required for flame propagation to occur. This is called the limiting oxygen concentration (LOC). The LOC depends on the inert gas being used, inerts with higher heat capacities being more efficient and giving higher values of LOC for a given flammable gas. For inerting with nitrogen the LOC for hydrogen is 5% v/v, while for inerting with carbon dioxide it is 6% v/v. Guidance on the application of the inerting technique can be found in the ISO published document PD CEN/TR 15282:2006[47].

Even if the formation of an explosive atmosphere cannot be prevented, then at a minimum, measures should be implemented to limit the extent of the explosive atmosphere. Such measures could include ventilation, use of gas tight seals on doors, pipe entry points, etc to prevent gas migration between rooms and compartments, and the use of a soft barrier. An example of a soft barrier is a curtain, made from polythene sheeting, which would allow easy access to the area where the gas source is, but would restrict the flow of gas to the surrounding areas.

4.4.2 Avoidance of ignition sources

If the formation of an explosive atmosphere cannot be prevented or the process operates with a flammable atmosphere, the next level of protection is the avoidance of ignition sources in areas where a flammable atmosphere may occur. The hazardous areas where explosive atmospheres could be formed have to be identified and classified according to the likelihood of an explosive atmosphere being present. For situations where hydrogen and/or other flammable gases or liquids may be present, the following classifications should be used where appropriate:

- Zone 0 – An area in which an explosive atmosphere is present continuously or for long periods. Only category 1 equipment should be used in these areas;
- Zone 1 – An area where an explosive atmosphere is likely to occur during normal operation. Only category 1 or 2 equipment should be used in these areas;
- Zone 2 – An area where an explosive atmosphere is not likely to occur during normal operation and, if it does occur, is likely to do so infrequently and will only last for a short period. Only category 1, 2 or 3 equipment should be used in these areas.

Guidance on identifying and classifying the hazardous areas is given in BS EN 60079-10:2003[44] and BS EN 1127-1:2007[43].

Electrical and non-electrical equipment appropriate for use in the different areas of the workplace should be determined once the hazardous areas have been identified and classified. The EN 60079 series of standards specifies the requirements and testing of electrical equipment for use in the different zones. Part 0[48] specifies the general requirements for the construction, testing and marking of electrical apparatus and components intended for use in hazardous areas where explosive gas/air mixtures exist under normal atmospheric conditions. Part 14[49] gives the specific requirements for the design, selection and erection of electrical installations in explosive gas atmospheres. These requirements are in addition to those for installations in non-hazardous areas. Part 17[50] covers the maintenance of electrical installations in hazardous areas and Part 19[51], the repair and overhaul for apparatus used in explosive atmospheres. Non-electrical equipment is covered by the BS EN 13463 series of standards, with Part 1[52] specifying the basic method and requirements for the design, construction, testing and marking of equipment. Methodology for the risk assessment of non-electrical equipment for use in potentially explosive atmospheres is given in BS EN 15198:2007[53].

The hazardous area classification should also be used to ensure that suitable controls are placed on all other foreseeable sources of ignition including hot work, smoking, vehicles, mobile phones and work clothing.

Precautions should also be taken to prevent the build-up of static charges that may lead to an incendive discharge. These may include:

- Ensuring that all pipe work is conductive and has effective electrical continuity, especially over mechanical joints such as flanges;
- Ensuring that all pipe work and equipment is effectively earthed;
- Carrying out and documenting appropriate earthing/continuity checks;
- Wearing antistatic clothing and footwear in hazardous areas.

Further information on the avoidance of hazards due to electrostatics can be found in the code of practice PD CLC/TR 50404:2003[54].

Appropriate protection is also required against the risk of lightning strike when designing outdoor fuel cell or hydrogen storage facilities.

4.4.3 Explosion mitigation

If explosive atmospheres may be present and ignition sources cannot be eliminated, then measures to mitigate the effects of the explosion, should an ignition occur, and prevent the explosion propagating to surrounding areas are required. There are a number of techniques available that can be employed to reduce the explosion pressure generated and/or contain the explosion within a given area.

4.4.3.1 Explosion venting

In this technique, weak areas (explosion vents) that fail early on in the explosion are deliberately incorporated in the item of equipment, venting the combustion products and so reducing the explosion pressure generated inside the equipment. There are a number of methods used to seal the vents, such as thin membranes, bursting discs, lightweight covers held in place by magnetic fasteners and spring loaded doors. The opening pressure of the covers and the size of the vents are chosen to give explosion pressures below that which would damage the equipment. It may, however, be acceptable to allow some damage to the equipment, e.g. bowing of panels, provided it does not result in damage to the adjacent area or injuries to nearby personnel. It should also be ensured that the explosion is vented to safe areas so it causes no damage or injuries. BS EN 14797:2006[55], BS EN 14994:2007[56] and NFPA 6857 provide guidance on the design of explosion relief systems and the methods of available for vent sizing.

4.4.3.2 Explosion suppression

Explosion suppression is achieved by injecting a suppressant agent, either water or a liquid or powder suppressant, into a developing explosion to quench it before the maximum explosion pressure is attained. Suppressing hydrogen explosions is particularly challenging due to the high flame speeds of hydrogen explosions. Basic requirements for the design and application of explosion suppression systems are given in BS EN 14373:2005[58].

4.4.3.3 Isolation systems

Explosion isolation is a technique that prevents an explosion pressure wave and a flame, complete isolation, or only a flame, partial isolation, from propagating via connecting pipes or ducts into other parts of the plant. The distinction between the two types is important as in some applications it may only be necessary to achieve flame isolation. The systems can be either be an active type, which requires a means of detecting the explosion and initiating an action to implement the isolation, or passive and requires no additional equipment to function. Examples of an active system are a quick acting valve, a complete isolation system, or an extinguishing barrier. The later system provides partial isolation by injecting a curtain of suppressant into the pipe or duct to quench the explosion. An example of a passive partial isolation system is a flame arrester. This device contains an arresting element, comprising a matrix of small apertures or convoluted gas pathways, with dimensions large enough to allow gas flow with minimal pressure drop, but small enough to quench and prevent the passage of flame through the element. A standard (prEN 15089[59]) is under development that will specify the general requirements for explosion isolation systems, excluding flame arresters, and the methods for evaluating the effectiveness of different systems. BS EN 12874:2001[60] specifies the performance requirements, test methods and limits for use of flame arresters.

4.4.3.4 Containment systems

An alternative mitigation technique to those that aim to reduce the explosion pressure is to use equipment, for example process vessels, strong enough to contain the explosion. Equipment intended to withstand an internal explosion are classed as one of two types. Explosion-pressure-resistant equipment is designed to withstand the expected internal explosion pressure without becoming permanently deformed. Explosion-pressure-shock resistant equipment is designed to withstand the expected internal explosion pressure without rupturing, but allowing for some permanent deformation. EN 14460:2006[61] specifies the requirements of the two classes of equipment.

4.4.3.5 Blast walls

Equipment and plant vulnerable to blast damage can be protected by blast walls. These are strong walls positioned between the item to be protected and the expected source of blast that will deflect the blast wave and thus reduce the intensity of explosion pressure experienced. They can also provide protection from missiles generated by the explosion. The possible beneficial and detrimental effects of blast walls on the dispersion of leaking gas need to be taken into account in the assessment of the explosion hazards. Depending on the circumstances, for example wind direction and site layout, blast walls may limit the spread of an explosive gas/air cloud. On the other hand, walls may extend the time an explosive cloud is present and thus the likelihood of an ignition, by inhibiting the dispersion of the gas by the wind. These effects are more likely to be important for gases other than hydrogen, as due to its low density there will be a significant upward dispersal due to buoyancy. An experimental and modeling programme on the effects of walls and barriers has been carried out within HYPER and details can be found on the project website[1].

4.5 HYDROGEN SENSING

As a colourless, odourless and tasteless gas, hydrogen cannot be detected by human senses, therefore, means should be provided to detect the presence of hydrogen in locations where leaks and/or accumulations may occur. When using hydrogen in confined spaces, the employment of a hydrogen detection system for early detection of leaks is essential to facilitate the activation of alarms, safety operations and where necessary, the safe evacuation of people. There are numerous hydrogen sensors/detectors commercially available operating on various principles.

When installing a hydrogen gas detection system, the following questions need to be considered:

- Which is the most suitable sensing technology?
- What are the appropriate alarm thresholds for the hydrogen detection system?
- How many sensors are required?
- Where should the sensors/detectors be located?

Consulting relevant standards, regulations and guidelines can assist in the choice and correct use of a particular type(s) of hydrogen detection system most suitable for an application. Technical standards for flammable gas detectors have existed for many years, although not specifically for hydrogen. The most useful among the technical standards are the BS EN 61779 series of standards[62], although they do not specifically focus on hydrogen. The development of a standard specific to the performance and testing of hydrogen detection apparatus is underway (ISO Technical Committee 197 - WG13). Further information on regulations, codes and standards relating to flammable gases and hydrogen is published in Chapter 6 of the HySafe Biennial Report on Hudrogen Safety[63] and some useful regulations codes and standards are also listed in Appendix 1.

Detection techniques, sensor positioning, alarm levels, sensor maintenance and calibration are discussed in Appendix 4.

4.6 FIRE PRECAUTIONS

Fire precautions are relevant for all aspects of the fuel cell installation, from the hydrogen generation, processing, storage, and piping, to the fuel cells. A fire can often lead to an explosion and, by the same token, an explosion can initiate a fire. It is important, therefore, that a fire and explosion risk assessment be carried out as a single exercise that considers all the fire and explosion hazards that can arise.

Fire precautions are often referred to as process fire precautions (PFP) and general fire precautions (GFP). PFP are special precautions that are required for the work activity being undertaken to prevent or reduce the likelihood of a fire occurring or to limit the extent of the fire. GFP are those basic measures taken to ensure people's safety in the event of a fire, e.g. general measures to prevent fire, means of escape, provision of fire extinguishers, fire detection and alarms and staff training.

General fire precautions for the workplace are set out in the Workplace Directive (89/654/EEC)[64], which specifies the minimum requirements for health and safety in the workplace. These requirements are implemented in England and Wales by the Regulatory Reform (Fire Safety) Order 2005[65], in Scotland by Fire (Scotland) Act 2005[66] and came into force on 1 October 2006. Under the new legislation fire certificates are no longer required and instead a risk-based approach becomes the primary method to manage fire risk in the workplace. Responsibility for compliance will rest with the Responsible Person. In the workplace, this is the employer and any other person who may have control of any part of the premises, e.g. the occupier or owner. The duty of the Responsible Person is to ensure that a suitable and sufficient fire risk assessment has been carried out for the site. This amongst other things covers: means of detecting and giving warning of a fire at the site; measures to reduce the risk of fire and its spread; means of escape from the site, provision of fire fighting measures; and the safety fire of fighters. A recently published British Standard, BS 9999:2008[67], gives recommendations and guidance on the design, management and use of buildings to achieve reasonable standards of fire safety for all people in and around buildings.

4.6.1 Overheating

The fuel cell, and any hydrogen generation and processing equipment must be designed and constructed in such a way as to avoid any risk of a fire being initiated by overheating. Some types of fuel cell operate at temperatures in the range of 600 to 1000^{0}C, so even under normal conditions a high standard of thermal insulation will be required to prevent nearby equipment from overheating.

4.6.2 Fire fighting

Fires involving hydrogen should not be approached without appropriate flame detection equipment due to the low visibility of hydrogen flames. Hydrogen fires should not be extinguished until the supply of hydrogen is shut off because of the danger of re-ignition or explosion of an accumulation of unburnt hydrogen. The recommended way of handling a hydrogen fire is to let it burn under control until the hydrogen flow can be stopped. Small hydrogen fires can be extinguished by dry chemical extinguishers or with carbon dioxide, nitrogen, and steam. Water in large quantities is the best way of extinguishing anything other than a small hydrogen fire, and is required for spraying adjacent plant to keep it cool and preventing fire spread. Water spray systems should be provided for hydrogen storage containers, grouped piping, and pumps where potential fire hazards exist. The system(s) shall be arranged to deliver a uniform spray pattern over 100 per cent of the container surface, pumps, and adjacent piping. Manual control stations shall be located outside the hazardous area, but within effective sight of the facility protected.

No attempt should be made to extinguish fires involving hydrogen or other flammable gas cylinders, unless they are in the open or in a well-ventilated area free of combustibles and ignition sources. Even if located in open or well-ventilated areas, extreme care should still be taken in attempting to extinguish the fire, as this may create a mixture of air and escaping gas that, if re-ignited, might explode. Under no circumstances should firefighters attempt to remove a burning cylinder. An appropriate exclusion zone should be set-up and the burning cylinder(s), and any surrounding cylinders and combustibles, should be kept cool by spraying them with water until the gas escape ceases and the fire extinguishes.

4.6.3 Emergency plan

A fire protection and emergency plan should be drawn up. Personnel should receive specific training in dealing with emergencies involving hydrogen. In particular they should know how hydrogen explosions and fires differ from those involving the more conventional gaseous fuels such as natural gas and LPG. One example of a difference, which is of particular relevance to hydrogen fires, is that hydrogen flames are often invisible, especially in bright sunlight, increasing the likelihood of people fleeing an incident or emergency workers inadvertently straying into a flame.

4.7 INTERCONNECTIVITY

Manufacturers of equipment intended to be connected to networks should construct such equipment in a way that prevents networks from suffering unacceptable degradation of service when used under normal operating conditions. In the UK Technical Note G83/1-1[68] covers the connection of small-scale generators to local power distribution networks.

5 PERMITTING ROUTE

Currently there is no formalised route for the approval of a hydrogen and fuel cell stationary installation.

Guidance on installation can be found in BS EN 62282-3-3 2008[2].

The permitting route required for a particular installation should be proportionate to the scale and complexity of the installation. Domestic or residential installations are likely to require a simpler permitting route than a commercial or industrial installation and for this reason different permitting routes are proposed for the two types of installation.

The approval checklist below is intended to apply to both new-build and retro-fitted installations.

5.1 OUTLINE APPROVAL CHECKLIST FOR COMMERCIAL/INDUSTRIAL INSTALLATIONS

Step 1 – risk assessment

Undertake a risk assessment to identify the hazards and the measures to be implemented to eliminate or mitigate their effects. The principal hazards will be fire and explosion ones (see 4.4 and 4.6), but other hazards, e.g. electrical, pressure and weather (for outdoor installations) related, also need to be considered. The hazards arising throughout the lifetime of the installation have to be covered by the assessment. This would include those hazards associated with the installation of the equipment, start up and shutdown of the equipment, delivery of consumables (e.g. gas cylinders) and the maintenance and repair of the equipment. Guidance on how to undertake a risk assessment can be found in Appendix 5.

For workplaces it is a legal requirement, under DSEAR, for the employer to identify the fire and explosion hazards, classify areas where explosive atmospheres may exist, evaluate the risks and specify measures to prevent, or where this is not possible mitigate the effects, of an ignition. Further information on explosion control and mitigation measures is given in 4.4.

5.1.1 EU Directives

The equipment used in the installation must comply with the essential health and safety requirements of all applicable EU Directives. Compliance confirmed by the CE marking for each applicable Directive (see 3.1 and Appendix 3).

For a hydrogen fuel cell installation the applicable Directives and the UK implementing regulations are:

ATEX Equipment Directive [EPS Regulations[13]] - Applies to any equipment (electrical or non-electrical) or protective system designed, manufactured or sold for use in a potentially explosive atmosphere.

Pressure Equipment Directive (PED) [Pressure Equipment Regulations[15]] - Applies to the design, manufacture and conformity assessment of pressure equipment with a maximum allowable pressure greater than 0.5 bar above atmospheric over the temperature range it is designed for.

Low Voltage Directive (LVD) [The Electrical Equipment (Safety) Regulations[18]] - Applies to electrical equipment designed for use with a voltage rating of between 50 and 1,000 V for AC and between 75 and 1,500 V for DC.

Electromagnetic Compatibility Directive (EMC) [The Electromagnetic Compatibility Regulations[17]] - Applies to commercially available equipment, or combinations of equipment made into a single unit, intended for an end user and liable to generate electromagnetic disturbance, or the performance of which is liable to be affected by such disturbance.

Gas Appliances Directive (GAD) [The Gas Appliances (Safety) Regulations[15]] - Applies to appliances burning gaseous fuels used for cooking, heating, hot water production, refrigeration, lighting or washing and having, where applicable, a normal water temperature not exceeding 105°C. Note though fuel cells do not burn gaseous fuels and should be excluded from the scope of the Directive, guidance issued on what appliances are covered by the Directive includes fuel cells where the primary function is heating. The Directive also covers such components as safety, regulating and controlling devices which may fitted in the gas side of a fuel cell or a reformation unit for generating hydrogen.

Machinery Directive [Supply of Machinery (Safety) Regulations[19,20,21]] - Applies to machinery, interchangeable equipment, safety components, lifting accessories, chains, ropes and webbing, removable mechanical transmission devices and partly completed machinery. This would not apply to the fuel cell installation itself, but may apply to associated equipment required for operating the installation, e.g. a hoist for lifting gas cylinders.

Prototype equipment does not need to comply with EU Directives and be CE marked. Nonetheless it is recommended that the general principles of the essential health and safety requirements are taken into account in the design of a prototype installation.

5.1.3 Step 3 – other legislation

The installation needs to meet legislation dealing with planning approval, building regulations (see 3.3.1) and fire regulations (see 4.6). Installations that are connected to the electrical distribution network, for exporting surplus electricity back to the grid, will need to meet electrical regulations for interconnectivity of supplies (see 4.7).

5.1.4 Step 4 – installation issues

The equipment to be installed, and maintained, by a competent person. At present there is no national scheme in place for training and assessing the competency of persons to install hydrogen systems, although some manufacturers do have schemes for training installers and service engineers.

5.1.5 Step 5 – emergency responders

The local fire brigade to be informed of the location and type of installation and given the opportunity to visit the installation. Of particular interest would be the location and quantity of any hydrogen stored at the site.

5.2 OUTLINE APPROVAL CHECKLIST FOR DOMESTIC/RESIDENTIAL INSTALLATIONS

Step 1 – risk assessment

Undertake a risk assessment to identify the hazards and measures to be implemented to eliminate or mitigate their effects. For domestic installations at best a fairly basic risk assessment will be required and may not be required at all in some cases, e.g. for an integrated CHP system. In these cases it will be sufficient that the equipment is installed according to the manufacturer's instructions, as in drawing up these instructions the manufacture will have undertaken a risk assessment. Guidance on how to undertake a risk assessment can be found in Appendix 5.

5.2.1 Step 2 – EU Directives

For residential installations there is no legal requirement to use ATEX compliant equipment as the ATEX Directives only apply to the workplace. Pressure equipment will still need to comply with the requirements of PED and electrical equipment with LVD and ECM. Fuel cells where the primary function is heating will have to comply with GAD and it is also recommended that gas safety, regulating and controlling devices on the installation meet the requirements of GAD. For further information on these Directives see section 5.1.2.

5.2.2 Step 3 – other legislation

The installation needs to meet national legislation dealing with planning approval, building regulations and fire regulations. For residential applications they will probably only need to comply with the building regulations (see 3.3.1). These as well as dealing with construction requirements of the building also deal with issues including fire safety, ventilation, sound insulation and energy efficiency. Installations that are connected to the electrical distribution network, for exporting surplus electricity back to the grid, will need to meet national electrical regulations for interconnectivity of supplies (see 4.7).

5.2.3 Step 4 – installation issues

The equipment to be installed, and maintained, by a competent person. At present there is no national scheme in place for training and assessing the competency of persons to install hydrogen systems, although some manufacturers do have schemes for training installers and service engineers.

5.2.4 Step 5 – emergency responders

The local fire brigade to be informed if there will be hydrogen stored, e.g. gas cylinders, at the premises. It is also recommended that the property insurers are informed of the installation.

6 APPENDIX 1 – USEFUL CODES AND STANDARDS

Table 1.1 lists useful codes and standards. Codes and standards are under continuous update and review. For the latest status of the hydrogen and fuel cell codes and standards the user is referred to: http://www.fuelcellstandards.com.

Table 1.1 - Listing of useful codes and standards

Application/topic	Applicable codes and standards
Hydrogen system specifications	BS EN 62282-3-1: 2007. Fuel cell technologies – Part 3.1:Stationary Fuel Cell Power Systems – Safety.
	BS ISO 16110-1:2007. Hydrogen generators using fuel processing technologies. Safety.
	Supply of Machinery (Safety) Regulations.
	The Gas Appliances (Safety) Regulations 1995
	EN 50465: 2008. Gas appliances-Fuel cell gas heating appliance nominal heat input up to 70kW.
	BS EN 13611: 2007. Safety and control devices for gas burners and gas-burning appliances - general requirements.
	BS EN 161:2002. Automatic shut-off valves for gas burners and gas appliances.
	BS EN 298:2003. Automatic gas burner control systems for gas burners and gas burning appliances with or without fans.
	BS EN 437:2003. Test gases. Test pressures. Appliance categories.
	BS EN 483:1999. Gas-fired central heating boilers. Type C boilers of nominal heat input not exceeding 70 kW.
	BS EN 677:1998. Gas-fired central heating boilers. Specific requirements for condensing boilers with a nominal heat input not exceeding 70 kW.
	BS EN ISO 12100-1:2003. Safety of machinery. Basic concepts, general principles for design. Basic terminology, methodology.
	BS EN ISO 12100-2:2003. Safety of machinery. Basic concepts, general principles for design. Technical principles.
	BS EN 50165:1997. Electrical equipment of non-electric appliances for household and similar purposes. Safety requirements.
	BS EN 60079-14:2008. Explosive atmospheres. Electrical installations design, selection and erection.
	BSEN60079-17:2007. Explosiveatmospheres. Electricalinstallations inspection and maintenance.
	BS EN 60079-19:2007. Explosive atmospheres. Equipment repair, overhaul and reclamation
	BS EN 60204-1:2006. Safety of machinery. Electrical equipment of machines. General requirements

Hydrogen system specifications	BS EN 60335-1:2002. Specification for safety of household and similar electrical appliances. General requirements.
	BS EN 60529:1992. Specification for degrees of protection provided by enclosures (IP code).
	BS EN 60730 series. Automatic electrical controls for household and similar use.
	BS EN 60950-1:2006. Information technology equipment. Safety. General requirements.
	BS EN 61000-6-2:2005. Electromagnetic compatibility (EMC). Generic Standards. Immunity for industrial environments.
	BS EN 61000-6-4:2001. Electromagnetic compatibility (EMC). Generic standards. Emission standard for industrial environments.
	ANSI/AIAA G-095-2004. Guide to Safety of Hydrogen and Hydrogen System. American National Standards Institute/American Institute of Aeronautics and Astranautics.
Fire safety	Regulatory Reform (Fire Safety) Order 2005.
	Fire (Scotland) Act 2005.
	PD 6686:2006. Guidance on directives, regulations and standards related to prevention of fire and explosion in the process industries.
Hydrogen systems installation	BS EN 61779 series (Parts 1 to 5). Electrical Apparatus for the Detection and Measurement of Flammable Gases.
	BS EN 60079-29-1:2007. Explosive atmospheres. Gas detectors. Performance requirements of detectors for flammable gases.
	BS EN 60079-29-2:2007. Explosive atmospheres. Gas detectors. Selection, installation, use and maintenance of detectors for flammable gases and oxygen.
	BS EN 62282-3-3: 2008. Fuel cell technologies – Part Stationary fuel cell power systems – Installation.
	EN 60079-10:2003. Electrical apparatus for explosive gas atmosphere. Classification of hazardous areas.
	HSG243. Fuel cells – Understand the hazards, control the risks. HSE Books.
	An Installation Guide for Hydrogen Fuel Cells and Associated Equipment (Draft). UK Hydrogen Association.
	CGA G-5.4. Standard for Hydrogen Piping Systems at Consumer Sites. Compressed Gas Association.
	CGA G-5.5. Hydrogen Vent Systems. Compressed Gas Association.
	NFPA 853: 2007. Standard for the Installation of Stationary Fuel Cell Power Plants. National Fire Protection Association.
	ASME B31. Hydrogen Piping and Pipeline Project Team. American Society of Mechanical Engineers.

Hydrogen storage	BS EN ISO 11114-1:1998. Transportable gas cylinders. Compatibility of cylinder and cylinder valve with gas contents. Metallic materials.
	BS EN ISO 11114-4:2005.Transportable gas cylinders . Compatibility of cylinder and cylinder valve with gas contents. Test methods for selecting metallic materials resistant to hydrogen.
	NFPA 55. Standard for the Storage, Use and Handling of Compressed Gases and Cryogenic Fluids in Portable and Stationary Containers, cylinders, Equipment and Tanks. National Fire Protection Association.
	CGA C-10. Recommended procedures for changes of gas service of compressed gas cylinder. Compressed Gas Association.
	IGC Doc 100/03/E. Hydrogen cylinders and transport vessels. European Industrial Gases Association.
	CGA PS-20 CGA. Position Statement on the Direct Burial of Gaseous Hydrogen Storage Tanks. Compressed Gas Association.
	CGA PS-21. Position Statement on Adjacent Storage of Compressed Hydrogen And Other Flammable Gases. Compressed Gas Association.
	CGA Doc 02-50. Hydrogen Storage in Metal Hydrides. Compressed Gas Association.
General hydrogen safety	Biennial Report on Hydrogen Safety. HYSAFE Network of Excellence.
	Guidance for using hydrogen in confined spaces. InsHYde project (internal project of the HYSAFE Network of Excellence).
	ISO TR 15916:2004. Basic Considerations for the Safety of Hydrogen Systems.
	Dangerous Substances and Explosive Atmospheres Regulations (DSEAR) 2002.
	ANSI/AIAA G-095-2004. Guide to Safety of Hydrogen and Hydrogen System. American National Standards Institute/American Institute of Aeronautics and Astranautics.
	CGA P-6. Standard Density Data, Atmospheric Gases and Hydrogen. Compressed Gas Association.
	NFPA 50A. Standard for gaseous hydrogen system at consumer sites. National Fire Protection Association.
	The Fire Protection Research Foundation Technical Report. Siting Requirements for Hydrogen Supplies Serving Fuel cells in Non-combustible Enclosures.
Safety distances	IGC Doc 15/06/E. Gaseous Hydrogen Stations. European Industrial Gases Association.
	IGC Doc 75/01/rev. Determination of Safety Distances. European Industrial Gases Association.
	ISO TR 15916:2004. Basic Considerations for the Safety of Hydrogen Systems.
	NFPA 50A, 50B, 52 and 55. National Fire Protection Association.
Fuel cells - general	BS EN62282-3-1:2007. Fuel cell technologies – Part 3-1: Stationary fuel cell power systems – Safety.

Fuel cells - general	BS EN 62282-3-2:2006. Fuel cell technologies – Part 3-2: Stationary fuel cell power plants - Performance test methods.
	BS EN 62282-3-3:2008. Fuel cell technologies – Part 3-3: Stationary fuel cell power systems – Installation.
Hydrogen fuel	ISO 14687:1999. Hydrogen fuel. Product specification.
	ISO/TS 14687-2:2008. Hydrogen fuel. Product specification. Part 2: Proton exchange membrane (PEM) fuel cell applications for road vehicles.
Hydrogen sensors	BS EN 61779, Parts 1 to 5. Electrical apparatus for the detection and measurement of flammable gases.
	BSEN60079-29-1:2007. Explosiveatmospheres. Gasdetectors. Performance requirements of detectors for flammable gases.
	BS EN 60079-29-2:2007. Explosive atmospheres. Gas detectors. Selection, installation, use and maintenance of detectors for flammable gases and oxygen.
	ISO / DIS 26142. Hydrogen Detection.
	EN 50073:1999. Guide for selection, installation, use and maintenance of apparatus for the detection and measurement of combustible gases or oxygen.
	BS EN 62282-3-3:2008. Fuel cell technologies – Part 3-3: Stationary fuel cell power systems – Installation.
	ISO TR 15916:2004. Basic Considerations for the Safety of Hydrogen Systems.
	ANSI/AiAA G-095-2004. Guide to Safety of Hydrogen and Hydrogen System. American National Standards Institute/American Institute of Aeronautics and Astranautics.
Explosion venting	EN 14994:2007. Gas Explosion Venting Protective Systems.
	NFPA 68. Standard on explosion protection by deflagration venting (2007 edition). National Fire Protection Association.
Electrolysers	BS ISO 22734-1:2008. Hydrogen generators using water electrolysis process. Industrial and commercial applications.
	ISO/CD 22734-2 Hydrogen generators using water electrolysis process -- Part 2: Residential applications.
Reformers	BS ISO 16110-1:2007. Hydrogen generators using fuel processing technologies. Safety.
	ISO/DIS 16110-1:2007. Hydrogen generators using fuel processing technologies – Part 2: Procedures to determine efficiency.

7 APPENDIX 2 – CASE STUDIES

The aim of the case studies undertaken as part of the HYPER project was to review and look at a broad range of installations and environments. By collecting this information it was hoped to compare best practise and harmonise local technical and non-technical variations. One of the UK case studies is reproduced below as an example of the type of installation that is currently operating in the UK. Further information on the case studies can be found on the HYPER website (www.hyperproject.eu).

DUDLEY, UNITED KINGDOM

1 Details of the Fuel Cell System

Application	:**Combined heat and power**
Customer/user	:**Black Country Housing**
Country	:**England**
City/Town	:**Dudley West Midlands**
Date	:**2008/2009**

Hyper Partner :HSL

Fuel Type:

Natural gas	YES	Hydrogen		Other *	

**** Description:*** *Natural Gas*

Status of development:

Prototype		Verification model	YES	Serial model		Other *	

**** Description:*** *Verification model*

CE Certification (for each component): THE WHOLE SYSTEM WAS CE MARKED

Component Name	CE Certification			
1.Stack	YES 1)		NO 2)	
2.H2 Supply system	YES 1)		NO 2)	
3.Electrical supply/inverter	YES 1)		NO 2)	
4.Control panel	YES 1)		NO 2)	
5.Heat exchanger	YES 1)		NO 2)	
6.Heat Store				
7. Electrical supply				
8.Battery Pack				

1) **Which directives were used?**

Hazop performed and Risk Assessment with HSE.
Planning authority consulted but they said it was outside their control.
Building control advised to treat it as an outside experiment.
Fire Brigade did not have a procedure – one was written by Richard Baines which they adopted.
Supply of gas (BOC) covered by Gas Regs
This procedure was used for 1st installation (2003) was adopted again.
Inform grid the system is going to be connected or disconnected (G83).

Which standards were used?

IGEM (Institution of gas engineers and managers) and IET (Institution of engineering and technology)

Who certified each component/the overall system?

BAXI had the system CE marked in Germany

- **Please provide a copy of the certificate of conformance.**

2) Was a risk analysis carried out? YES

- Please provide HAZOP information.
- Please provide information regarding to safety measures taken (i.e. fire protection, ventilation, safety sensor, etc)

The system was housed in a wooden shed it was treated more as a natural gas system would have been treated. Fitted with leak detectors.

Nominal data:

Power out (kWe)	1.5kW
Heat out (kWth)	3.0kw
Fuel gas supply pressure (bar)	18 to 25 mbar
Voltage (V)	230
Frequency (Hz)	50
Ambient temperature range (°C)	
IP-rating	
Dimensions (m)	100cm x 73 cm x 185 cm
Weight (kg)	350

2 Installation

Location:

	Indoor	Outdoor
Remote		
Industrial		
Residential	Yes (lean-to shed)	

Additional information:

(e.g. single/multi family home, rooftop, laboratory, etc)

Single family home. Located in a shed attached to the house.

What affected your choice of site location?

Availability of site.

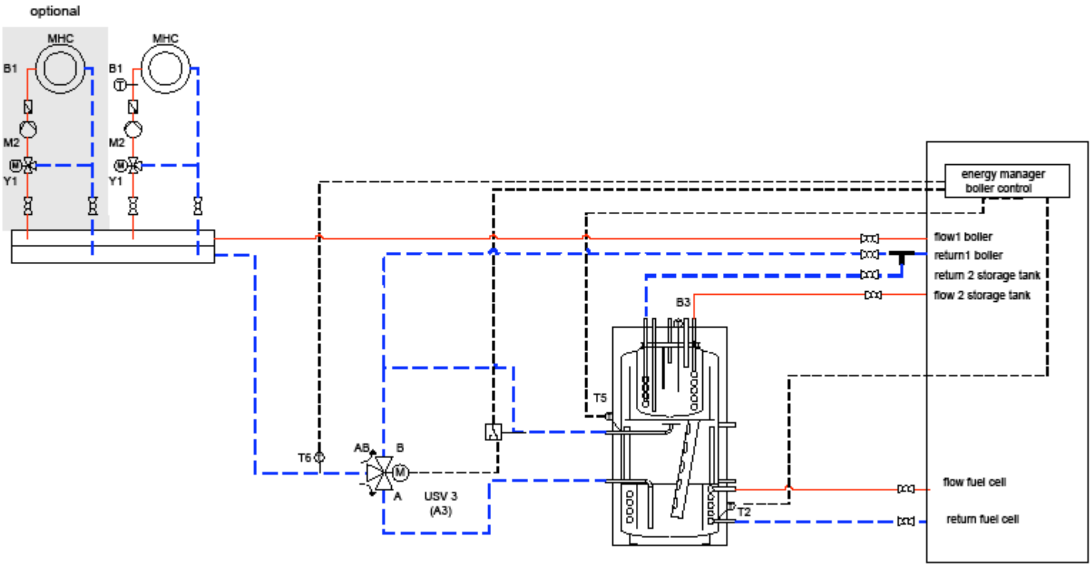
Installed by:

	Name, contact details
Installation company	Energised Ltd
Manufacturer	BAXI INNOTECH GmbH)
Service company (maintenance)	Energised
Other	

Please provide copies of installation manuals, service & operational manuals and training material.

2.1 Before & during installation

Schematic drawing of installation (electrical & mechanical):



Site evaluation:

1. What safety and security measures were taken for each component of the fuel cell system? (e.g. ventilation, fire protection, sensors, barriers, walls, locks)

Considered under HAZOP and under site choice.

Fuel supply:

Piped	YES	**Generated on site**		Stored on site [1)]	

1) **Describe the fuel storage and any safety devices related to the storage, (e.g. number of cylinders used, size of tank used, storage pressure, materials used etc)**

Natural Gas

2) **Describe fuel piping used between components (material, length, internal and external diameter if known, shape connections, etc):**

N/A

3) Describe what precautions were taken if the piping went through a wall (type of wall, type of sealing, piping instructions, fire protection, smoke protection, etc):

N/A

If the fuel cell was connected to a grid or appliance, what criteria had to be fulfilled?

The fuel cell was connected to the grid. Standard connection criteria for connection of distributed power generation to local distribution network was used (G83/1-1 2008 Engineering Recommendations).

2.2 After installation

What training did the installers, users and service personnel receive?

BAXI trained the installer and service personnel.
No intervention by the user.

What emergency procedures are/were in place?

Fire Brigade were made aware of location of installation and a special tel number was issued in case of emergencies.
Remotely monitored by (PLC) by BAXI.

If an approval route was necessary, describe by whom and what was needed?

The system was CE marked and similar procedures were followed as 1st installation.

Was any commissioning of the installation carried out? If so please provide details.

Commissioned in lab and then re-commissioned on site by manufacturer

Please describe the service procedure?

Re-commissioned on every service – period of service based on usage, running time and stops and starts

3 Lessons learned

What were the challenges/hurdles for approval?

Public perception of H2 (not good)
Fear of H2
No standards for installation in place lack of guidance
Is it gas or electrical?
Lack of knowledge within industry

What were the challenges/hurdles for installation?

Peripheral trades e.g. engineers and electricians were not sure of what to do.
Integrating the system with existing structures.

What problems were caused by techniques?

Small issue with lifting gear.

What problems were caused by administration, agencies?

N/A

What difficulties did the installer experience?

Lack of knowledge within industry.
I.T difficulties with German software, internet transfer and protocol.

What difficulties were experienced by the customer?

None

Describe any modifications to the installation process?

N/A

In your opinion, if a leak were to occur in the system, where would it be most likely to occur and what would be the most likely causes of the leak? (Describe multiple situations if necessary.)

N/A

8 APPENDIX 3 – CE CERTIFICATION

1. Check list

The following check-list should be used when seeking CE certification.

- Identify the directive(s) that are applicable to the different components of the fuel cell system.
- Identify the conformity assessment procedure that must be taken for each component being certified, whether self-declaration or assessment by a Notified Body or a combination of these.
- Be aware of when the directive(s) come into force.
- Identify if there are any Harmonised European Standards applicable to your product.
- Ensure the components of the fuel cell system comply with the essential requirements of the directive(s) used.
- Maintain technical documentation (see section 2) required by the directive(s). Your technical documentation should support your compliance with the requirements of the directive. It is essential to retain this documentation.
- Provide, in particular, the necessary information, such as instructions;
- Prepare the Declaration of Conformity and the required supporting evidence. The Declaration of Conformity along with the technical documentation should be available to competent authorities (EU Members) upon request.
- Check that no other purely national requirements exist in the countries where the product will be sold. These may include national standards, labelling or packaging requirements.
- Affix CE marking on your product and/or its packaging and accompanying literature as stated in the directive. In order to ensure the same quality for the CE marking and the manufacturer's mark, it is important that they be affixed according to the same techniques. In order to avoid confusion between any CE markings which might appear on certain components and the CE marking corresponding to the machinery, it is important that the latter marking be affixed alongside the name of the person who has taken responsibility for it, namely the manufacturer or his authorised representative.

2. Technical file

The technical file must demonstrate that the equipment complies with the requirements of the relevant directive(s). It must cover the design, manufacture and operation of the equipment to the extent necessary for assessment. The technical file must be compiled in one or more official Community languages, except for the instructions for the machinery, for which the special provisions apply and are described in the relevant directive(s).

The technical file shall comprise a construction file including:

- A general description of the equipment;

- The overall drawing of the equipment and drawings of the control circuits, as well as the pertinent descriptions and explanations necessary for understanding the operation of the equipment;

- Descriptions and explanations necessary for the understanding of said drawings and schemes and the operation of the electrical equipment;

- Full detailed drawings, accompanied by any calculation notes, test results, certificates, etc, required to check the conformity of the equipment with the essential health and safety requirements.

- The documentation on risk assessment demonstrating the procedure followed.

This documentation shall include:

- A list of the essential health and safety requirements which apply to the equipment;

- The description of the protective measures implemented to eliminate identified hazards or to reduce risks and, when appropriate, the indication of the residual risks associated with the equipment;

- The standards and other technical specifications used, indicating the essential health and safety requirements covered by these standards;

- Any technical report giving the results of the tests carried out either by the manufacturer or by a body chosen by the manufacturer or his authorised representative;

- A copy of the instructions for the equipment;

- Where appropriate, the declaration of incorporation for included partly completed equipment and the relevant assembly instructions for such equipment;

- Where appropriate, copies of the EC declaration of conformity of equipment or other products incorporated into the equipment;

- Where appropriate, for pressure systems, documentation relating to compliance with the materials specifications by using materials which comply with harmonised standards, by using materials covered by a European approval of pressure equipment materials or by a particular material appraisal;

- A copy of the EC declaration of conformity;

- Results of design calculations made, examinations carried out, etc;

- Test reports.

For series manufacture, the internal measures that will be implemented to ensure that the equipment remains in conformity with the provisions of the relevant directive(s).

The manufacturer must carry out necessary research and tests on components, fittings or the completed equipment to determine whether by its design or construction it is capable of being assembled and put into service safely. The relevant reports and results shall be included in the technical file.

The technical file must be made available to the competent authorities of the member states for at least 10 years following the date of manufacture of the equipment or, in the case of series manufacture, of the last unit produced. The technical file does not have to be located in the territory of the Community, nor does it have to be permanently available in material form. However, it must be capable of being assembled and made available within a period of time commensurate with its complexity by the person designated in the EC declaration of conformity. The technical file does not have to include detailed plans or any other specific information as regards the sub-assemblies used for the manufacture of the equipment, unless knowledge of them is essential for verification of conformity with the essential health and safety requirements.

3. EC declaration of conformity of the equipment

This declaration relates exclusively to the equipment in the state in which it was placed on the market, and excludes components that are added and/or operations carried out subsequently by the final user. The EC declaration of conformity must contain the following particulars:

- Business name and full address of the manufacturer and, where appropriate, his authorised representative;
- Name and address of the person authorised to compile the technical file, who must be established in the Community;
- Description and identification of the equipment, including generic denomination, function, model, type, serial number and commercial name;
- A sentence expressly declaring that the equipment fulfils all the relevant provisions of the relevant directive(s) and where appropriate, a similar sentence declaring the conformity with other directives and/or relevant provisions with which the equipment complies. These references must be those of the texts published in the Official Journal of the European Union;
- Where appropriate, the name, address and identification number of the notified body which carried out the EC type-examination and the number of the EC type-examination certificate;
- Where appropriate, the name, address and identification number of the notified body which approved the full quality assurance system;
- Where appropriate, a reference to the harmonised standards used;
- Where appropriate, the reference to other technical standards and specifications used;
- The place and date of the declaration;
- The identity and signature of the person empowered to draw up the declaration on behalf of the manufacturer or his authorised representative.

9 APPENDIX 4 – HYDROGEN DETECTION TECHNIQUES

There are several types of hydrogen sensors depending on its intended use. The electrochemical, catalytic and thermal conductivity detectors (TCD) are mainly used in the industries where the hydrogen risk is present. The metal oxide semi-conductor-based sensor (MOS) is most often used in research laboratories, whereas the MEMS (micro-electro-mechanic system) are used in the aeronautic and aerospace industries. Other less common but still commercially available sensors include gas field effect (GFE) type sensors and acoustic sensors. The various types of hydrogen detection technologies currently in use are described in detail in Chapter 5 of the HySafe Biennial Report on Hydrogen Safety (BRHS)[1] together with a description of emerging technologies for hydrogen detection.

Some important factors to consider in the selection of a hydrogen sensor include accuracy, measuring range, response time, ambient working conditions, lifetime and stability (see ISO/TR15916[2]). A market investigation on the performance of commercially available sensors has been performed (see HYSAFE deliverable D5.4[3]); the investigation was based on the technical information (product specifications, datasheets) made available by manufacturers.

Some general hydrogen performance targets for hydrogen safety sensors are given below[4]:

- Measurement range:0.1–10% H_2 in air
- Operating temperature: -30–+80 °C
- Humidity range: 10-98%
- Response time: t[90] < 1 sec
- Accuracy: 5%
- Lifetime: 5 yrs

Considering these performance targets and the capabilities of commercially available hydrogen detection systems shortcomings of current detection techniques are highlighted in Table 4.1.

Table 4.1 - Indications where commercially available sensors meet or fail to meet current performance targets

Criteria	Target		Electrochem		Catalytic		MOS		Acoustic		TCD		GFE	
Measuring Range %	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**
	0.1	10	ü	û	ü	û	ü	û	ü	ü	ü	ü	ü	û
Temperature Range / °C	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**
	-30	+80	û	û	û	û	ü	ü	û	ü	ü	û	ü	ü
Humidity Range %RH	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**
	10	98	ü	û	ü	ü	ü	ü	ü	ü	ü	ü	ü	û
Response Time t[90] / s	<1		û		û		û		ü		û		û	
Accuracy %	5		-		ü		û		û		ü		-	
Lifetime / yrs	5		û		ü		ü		ü		ü		-	

Due to the considerable differences in the various requirements for indoor applications, no sensor type is currently capable of meeting all performance target sets. Each detection technology has advantages and disadvantages depending on its intended application. When considering a hydrogen detector for a particular application, the desired performance capabilities and ambient conditions for the application should be considered.

H_2 sensors positioning

The correct location of reliable sensors is crucial for timely detection and warning of hydrogen leaks before an explosive mixture is formed. Recommended locations for sensors include[2,5,6]:

- Evaluate and list all possible leak or spill sources to be monitored (valves, flanges, connections, bellows, etc) and provide valid justification for sources not monitored;
- At hydrogen connections that are routinely separated (for example, hydrogen refuelling ports);
- Locations where hydrogen could accumulate;
- In building air intake ducts, if hydrogen could be carried into the building;
- In building exhaust ducts, if hydrogen could be released outside the building.

The following points should also be considered[4]:

1. An understanding of how a gas leak disperses is required to choose the correct location to install the detection device(s). Hydrogen, being less dense than air, will rise when released and disperse rapidly.

2. When thinking of the location of hydrogen sensors/detectors, take the response time into consideration.

3. The LEL used shall be the LEL of the gas or gas mixtures.

4. When positioning detectors, local airflow also needs to be considered. Intuitively hydrogen detectors should be placed above a potential leak source however airflow may carry the hydrogen 'downstream', away from the detector and before reaching the ceiling. In that case detection may be delayed or even prevented.

5. Temperature can also have an effect on the dispersion of a gas. As hot air rises a layer of lower density air forms at the ceiling creating a 'thermal barrier' which may slow the diffusion of leaking hydrogen enough to delay detection at the sensor.

6. A combustible gas detector that meets the above requirements should be provided for all indoor or separately controlled gas compressors.
7. When hydrogen is stored as a cryogenic liquid and leaks, its density is initially greater than air causing it to settle to the ground before heating up, becoming lighter than air and eventually rising.

8. Dilution of hydrogen increases the further the detector is from the site of the leak. As a result the actual hydrogen concentration can be higher than the concentration indicated by the detection device when the device is located far from the leak site. For this reason detectors should be placed close to a potential leak site and should be sufficient in number to cover the installation.

9. It is recommended that a hydrogen sensor be placed at the most elevated point in an enclosed space.

10. If a forced ventilation system is installed then a sensor should be placed where the ventilation is applied.

Alarm levels

Alarms associated with hydrogen detection should be set as low a level as possible (≤ 10% LEL) without causing false alarms and should provide time to respond in a appropriate manner. Where the detection/shutdown system is a key part of the risk management system it should conform to an appropriate standard, e.g. EN 50073:1999[7].

Hydrogen system operators should have a portable hydrogen detector available for their use.

Once an alarm is triggered shutdown of the system should occur as quickly as possible to minimise the hydrogen inventory and hence the potential consequences of an ignition.

Ideally alarms should be audible and visible. Automatic corrective actions are actions that can be automatically triggered including forced ventilation, isolation of electrical components, isolation of hydrogen storage and auto-shutdown.

Hydrogen sensors maintenance and calibration

The performance of most sensors/detectors deteriorates with time, the rate depending on the type of sensor/detector and the operating conditions (e.g. dusty, corrosive or damp environment). Functioning must be checked with the frequency recommended by the manufacturer. Checking should include:

- appropriate cleaning, especially the head of the detector, to allow gas to reach the sensitive element;
- regular inspections for possible malfunctions, visible damage or other deterioration;
- that a zero reading is obtained in a clean atmosphere;
- that a correct response is obtained for exposure to a known concentration;
- that, if data logging is required, the logging period is appropriate for all data points over the required measurement time and can be stored in memory;
- the battery level, for portable instruments.

The best means to determine maintenance intervals for a sensor/detector is based on experience learned from use. For new installations it may be wise to carry out maintenance frequently at first (perhaps weekly), increasing the time intervals (to, perhaps, monthly) as confidence grows on the basis of the maintenance records with experience in the installation. Information on maintenance protocol should be found in the user manual supplied by the manufacturer.

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10 APPENDIX 5 – RISK ASSESSMENT METHODOLOGY

An example of the steps necessary to complete a risk assessment is given below. This is not the only way to perform a risk assessment but this method helps to assess health and safety risks in a straightforward manner. The law does not expected all risks to be eliminated, but protection of people as far as ‘reasonably practicable’ is required.

Step 1 - Identify the hazards.

The types of hazards identified and the methods used will vary according to the complexity of the installation.

Areas to be considered when identifying the hazards may/will include;

Site location, site evaluation, hydrogen storage location, security, choice of materials, access, deliberate attack and vandalism, impact, ventilation, fire protection, location of safety sensors, connection to grid.

A suitable emergency plan should be drawn up in the event of a leak or fire.

Step 2 - Decide who may be harmed and how.

For each hazard identified in Step 1 assess who might be harmed and how.

Step 3 - Evaluate the risks and decide what to do about them

Consideration should be given to removing the hazard and if that is not practical, how the hazard can be reduced or controlled.

Step 4 - Record and implement the findings

The risk assessment should show that all significant hazards have been recorded and addressed and how the hazards will be eliminated or if they cannot be eliminated how their effects will be minimised. Employees must be informed about the outcome of the risk assessment. The precautions taken should be reasonable and if there is a residual risk it should be low.

Step 5 - Review the Risk Assessment and update if and when necessary

Records of the installation, maintenance checks and servicing should be kept.

Any changes to the installation, work activities, process or incidents should be recorded and the risk assessment reviewed and if necessary additional safety measures implemented.

A risk assessment can be considered as “suitable and sufficient” if it has:

- correctly identified all the hazards
- disregarded inconsequential risks and those trivial risks associated with life in general
- determined the likelihood of injury or harm arising

- identified those who may be at particular risk, such as pregnant, elderly or disabled persons

- taken into account any existing control measures

- identified any specific legal duty or requirement relating to the hazard

- provided sufficient information to decide upon appropriate control measures, taking into account the latest scientific developments and advances

- enabled the remedial measures to be prioritised

- will remain valid for a reasonable period of time

A free download of an HSE leaflet giving more detail on the five steps to risk assessment is available at www.hse.gov.uk/pubns/indg163.pdf. Further assistance in producing risk assessments is available in books, videos and training sessions. Many consultancy organisations exist that can assist with or prepare risk assessments for their clients.

11 APPENDIX 6 – ABBREVIATIONS

AFC	alkaline electrolyte fuel cell
ATEX	ATmosphères EXplosibles (Explosive atmospheres)
BRHS	Biennial Report on Hydrogen Safety
CE	Conformité Européenne/European Conformity (the marking used to show conformity with a European Directive)
CFD	computational fluid dynamics
CHP	combined heat and power
CNG	compressed natural gas
DSEAR	Dangerous Substances and Explosive Atmosphere Regulations
EC	European Commission
EHSR	essential health and safety requirements
EIGA	European Industrial gases Association
EMC	Electromagnetic Compatibility Directive
EN	European norm (standard)
EPS	Equipment and Protective Systems for Use in Potentially Explosive Atmospheres Regulations
EU	European Union
FC	Fuel cell
GAD	Gas Appliances Directive
GFP	general fire precautions
HSE	Health and Safety Executive
HSL	Health and Safety Laboratory
IEC	International Electrotechnical Commission
IPG	Installation Permitting Guidance
ISO	International Standards Organisation
LEL	lower explosion limit

LOC	limiting oxygen concentration
LPG	liquefied petroleum gas
LVD	Low Voltage Directive
MCFC	molten carbonate fuel cell
MSDS	materials safety data sheet
NASA	National Aeronautics and Space Administration
NFPA	National Fire Protection Association
PACF	phosphoric acid fuel cell
PED	Pressure Equipment Directive
PER	Pressure Equipment Regulations
PEMFC	polymer electrolyte membrane fuel cell
PFP	process fire precautions
SOFC	solid oxide fuel cell
STREP	Specific Targeted Research project
UEL	upper explosion limit

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HSE

Health and Safety Executive

Installation permitting guidance for hydrogen and fuel cell stationary applications: UK version

The HYPER project, a specific targeted research project (STREP) funded by the European Commission under the Sixth Framework Programme, developed an Installation Permitting Guide (IPG) for hydrogen and fuel cell stationary applications. The IPG was developed in response to the growing need for guidance to foster the use and facilitate installation of these systems in Europe. This document presents a modified version of the IPG specifically intended for the UK market. For example reference is made to UK national regulations, standards and practices when appropriate, as opposed to European ones.

The IPG applies to stationary systems fuelled by hydrogen, incorporating fuel cell devices with net electrical output of up to 10 kWel and with total power outputs of the order of 50 kW (combined heat + electrical) suitable for small back up power supplies, residential heating, combined heat-power (CHP) and small storage systems. Many of the guidelines appropriate for these small systems will also apply to systems up to 100 kWel, which will serve small communities or groups of households. The document is not a standard, but is a compendium of useful information for a variety of users with a role in installing these systems, including design engineers, manufacturers, architects, installers, operators/maintenance workers and regulators.

Update November 2023
This report was published in 2009. Some of the information in the introductory section 2.3 relating to hydrogen viscosity and the potential for possible leaks from hydrogen systems has been superseded by the information in Research Report RR1169 (2022) ‘Hydrogen in the natural gas distribution network: Preliminary analysis of gas release and dispersion behaviour’. The superseded information does not affect the scientific information in the rest of this report. It has not affected any evidence assessment by HSE on using hydrogen including for heating. The Government's Hydrogen Strategy was published in August 2021.

Technical specialists may wish to note the details of the superseded information in introductory section 2.3.This is incorrect information on page 6. Firstly, in table 1, the gas viscosities should state (in g/cm-sec x 10-5 at normal temperature and pressure) 0.110, not 0.651 for methane, and 0.088, not 0.083 for hydrogen. Secondly the following technical statement is not correct: “Hydrogen gas has a very low viscosity and so it is very difficult to prevent hydrogen systems from developing leaks. Pipe work that was ‘leak tight’ when pressure-tested with nitrogen will often be found to leak profusely when used on hydrogen duty.” This incorrect statement is superseded by the information in RR1169 (2022).

This report and the work it describes were funded by the Health and Safety Executive (HSE). Its contents, including any opinions and/or conclusions expressed, are those of the authors alone and do not necessarily reflect HSE policy.

RR715

www.hse.gov.uk

APPENDIX 9: HYDROGEN IN THE NATURAL GAS DISTRIBUTION NETWORK

Hydrogen in the natural gas distribution network: Preliminary analysis of gas release and dispersion behaviour

Prepared by the **Health and Safety Executive**, **DNV GL Lander Consulting Limited, Progressive Energy Ltd,** and **Northern Gas Networks Ltd**

RR1169 (2022)

Research Report

Prepared 2020
First published 2022

Hydrogen has the potential to be used as part of decarbonising the future energy system. Hydrogen can be used as a fuel 'vector' to store and transport low-carbon energy. Several UK projects are investigating the potential use of the existing natural gas transmission and distribution network to transport either hydrogen, or blends of hydrogen and natural gas, from production or storage sites to domestic or commercial appliances such as boilers, cookers, fires and ranges. Mathematical modelling is important to inform risk assessments to ensure that levels of safety for the public are maintained.

This report describes preliminary mathematical modelling of potential leaks from gas network assets such as valves and pipes when hydrogen, or hydrogen blends, are transported or used. The research considers the potential impact of leak rates and the dispersion behaviour of the gas. It uses published information from laboratory-scale experiments. The report presents a preliminary modelling case study to show how this potential impact might affect a commonly-used UK gas industry leak tightness testing procedure.

This research will be of interest to risk assessment specialists in the gas industry.

This report and the work it describes were funded by: the Health and Safety Executive (HSE); and the Office of Gas and Electricity Markets (Ofgem) via the Network Innovation Competition projects 'H21' and 'HyDeploy2'. Its contents, including any opinions and/or conclusions expressed, are those of the authors alone and do not necessarily reflect HSE policy. including any opinions and/or conclusions expressed, are those of the authors alone and do not necessarily reflect HSE policy.

Hydrogen in the natural gas distribution network: Preliminary analysis of gas release and dispersion behaviour

Simon Gant[1], Ann Halford[2], Graham Atkinson[1], Adrian Kelsey[1], David Torrado[1], Phil Hooker[1], Dave Lander[3], Thomas Isaac[4], Russ Oxley[5], Andrew Garrison[1], Richard Goff[1], Catherine Spriggs[1]

1. Health and Safety Executive

Harpur Hill, Buxton, Derbyshire, SK17 9JN

2. DNV GL

Holywell Way, Loughborough, LE11 3UZ

3. Lander Consulting Limited

94 Sudeley, Dosthill, Tamworth, Staffordshire, B77 1JU

4. Progressive Energy Ltd

Swan House Bonds Mill, Bristol Rd, Stonehouse, GL10 3RF

5. Northern Gas Networks Ltd

Thorpe Business Park, 1100 Century Way, Colton,
Leeds, LS15 8TU

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[1] *Institut National de l'Environnement Industriel et des Risques, www.ineris.fr, accessed 28 April 2020*

KEY MESSAGES

Hydrogen has the potential to be used as part of decarbonising the future energy system. Hydrogen can be used as a fuel 'vector' to store and transport low-carbon energy.

Several UK projects are investigating the potential use of the existing natural gas transmission and distribution network to transport either hydrogen, or blends of hydrogen and natural gas, from production or storage sites to domestic or commercial appliances, such as boilers, cookers, fires and ranges. Mathematical modelling is important to inform risk assessments to ensure that levels of safety for the public are maintained.

This report describes preliminary mathematical modelling of potential leaks from gas network assets such as valves and pipes when hydrogen, or hydrogen blends are transported or used. The research considers the potential impact of leak rates and the dispersion behaviour of the gas. It uses published information from laboratory-scale experiments.

A modelling case study is presented to show how this might affect a commonly-used UK gas industry procedure for leak tightness testing. This research will be of interest to risk assessment specialists in the gas industry.

EXECUTIVE SUMMARY

There is currently significant interest in the UK in using hydrogen both in existing natural gas appliances and new hydrogen-ready appliances within residential, commercial and industrial buildings as a means of reducing carbon dioxide emissions and meeting climate-change targets. Several ongoing projects are investigating the feasibility of supplying hydrogen to properties using either the existing natural gas distribution network or a new purpose-built gas network.

Risk assessment is an important aspect of these projects. As part of the GB Gas Safety (Management) Regulations 1996, it must be demonstrated that changes to the gas quality do not prejudice the end users. To assess the risks when transitioning to low carbon gases, such as hydrogen, it is necessary to understand the likelihood of gas releases occurring and their consequences. This includes assessing leak rates, gas dispersion behaviour, ignition potential and the fire and explosion hazards.

This report presents a preliminary analysis of leak rates and dispersion behaviour of hydrogen-methane blends (with up to 100% hydrogen) using established empirical correlations taken from the literature. Fundamental properties of hydrogen and hydrogen-methane blends are first presented. The ratio of hydrogen to methane leak rates is then calculated across a range of pressures, using equations for laminar, turbulent, subsonic and choked flow. The analysis shows that for laminar leaks there is no significant increase in the volumetric flow rate when adding up to 70% hydrogen, due to the viscosity remaining practically unchanged. For blends with more than 70% hydrogen, the volumetric flow rate increases up to 1.23 times the methane value (for 100% hydrogen). Subsonic and choked releases are shown to behave similarly to incompressible turbulent releases and produce volumetric flows rates that increase continuously, at a rising rate, as the percentage of hydrogen is increased, up to 2.8 times for 100% hydrogen as compared to the equivalent methane volumetric flow rate.

The resulting behaviour of turbulent jets and buoyant plumes in air is then assessed in terms of the change in extent of the flammable cloud for hydrogen blends as compared to methane. For jets, it is shown that the flammable cloud extends 3.5 times further for 100% hydrogen than for methane. For buoyancy-dominated plumes, the difference between hydrogen blends and methane is less significant.

A model for gas accumulation in an enclosure with upper and lower ventilation openings is then presented and applied to study the gas tightness testing aspects of the Institute of Gas Engineers and Managers IGE/UP/1 procedure. Results from the analysis suggest that gas installations that have been leak tested in accordance with IGE/UP/1 should have no increase in risk of producing flammable clouds if the gas is switched from natural gas to a blend of 20% or 50% hydrogen in natural gas. However, the method used by IGE/UP/1 to define the Maximum Permitted Leak Rate (MPLR) for different gases in terms of energy content would lead to an increased risk of producing flammable clouds for hydrogen blends. It was shown that a possible solution to this issue could be to define the MPLR for hydrogen blends and 100% hydrogen to be the same as the current MPLR for natural gas in terms of volumetric flow rate instead of energy. The gas accumulation model predicts practically identical gas concentrations in terms of percentage LEL for pure methane, hydrogen blends and 100% hydrogen in that case.

CONTENTS

1 INTRODUCTION

There are several large-scale projects ongoing in the UK that are assessing the feasibility of supplying hydrogen to residential, commercial and industrial buildings. The H21 project[2] is focussed on repurposing the existing gas distribution network, whilst the H100 project[3] is proposing a new purpose-built network – in both cases for transporting 100% hydrogen. As part of the HyDeploy project[4], a trial is currently being undertaken at Keele University where a blend of 20% hydrogen in natural gas is being supplied to properties across the campus. The UK Government Department for Business, Energy and Industrial Strategy (BEIS) is also funding research under the Hy4Heat programme[5] on developing new hydrogen appliances, gas quality criteria and meters.

Risk assessment is an important aspect of these projects. As part of the GB Gas Safety (Management) Regulations 1996 (GSMR, 1996), it must be demonstrated that changes to the gas quality do not prejudice the end users. To assess the risks posed by the change in gas composition, it is necessary to understand the likelihood of gas releases occurring and their consequences. This includes assessing leak rates, gas dispersion behaviour, ignition potential and the fire and explosion hazards.

The aim of this report is to address two fundamental questions relating to leak rates and dispersion behaviour:

- For a given hole size, does hydrogen leak more than natural gas? If so, by how much?
- What is its effect on the size of the flammable cloud?

The gas pressures of interest span the range from domestic supply pressures of around 21 mbarg to the operating pressure of the UK National Transmission System (NTS) of around 85 barg. This preliminary study is focused on above-ground leaks, rather than those from buried assets, although some of the models discussed here are relevant to both cases.

The approach taken to answering these questions has been to use established empirical correlations taken from the literature and build upon previous work undertaken by others. The report starts by presenting the fundamental properties of hydrogen and hydrogen-blends. The ratio of hydrogen to natural gas leak rates is then calculated across a range of pressures, using equations for laminar, turbulent, subsonic and choked flow. The resulting behaviour of free jets and buoyant plumes in air is then assessed in terms of the change in extent of the flammable cloud for hydrogen (and hydrogen blends) as compared to methane. Finally, the UK Institute of Gas Engineers and Managers utilization procedure IGE/UP/1 is analysed to assess its implications for hydrogen. Throughout the report, to simplify the analysis, methane has been used as a substitute for natural gas.

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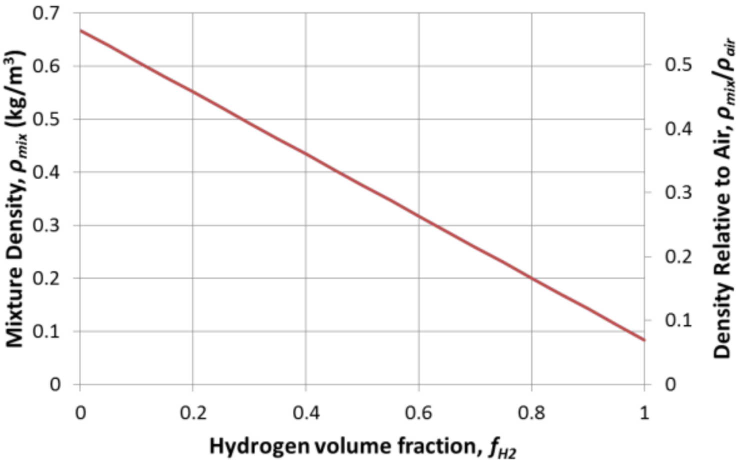
[2] *http://www.h21.green, accessed 25 November 2019.*
[3] *https://sgn.co.uk/about-us/future-of-gas/hydrogen/hydrogen-100, accessed 25 November 2019.*
[4] *https://hydeploy.co.uk/, accessed 25 November 2019.*
[5] *https://hy4heat.info, accessed 25 November, 2019.*

2 GAS PROPERTIES

The primary gas properties relevant to release and dispersion behaviour are the density, viscosity, specific heat capacity and flammable limits. Pure hydrogen has a molecular mass of M_{H2} = 2.016 g/mol and is therefore around 14 times lighter than air at the same temperature and pressure. In comparison, methane has a molecular mass M_{CH4} = 16.043 g/mol, and has a density just over half that of air. The density of gas mixtures is calculated from the volume-fraction weighted sum of the component gases, as shown in Figure 1a.

a.)



b.)

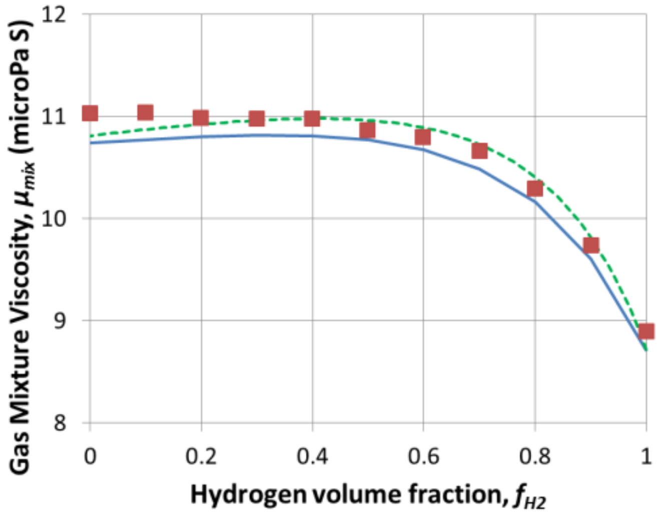


Figure 1 a.) Density of hydrogen-methane blends (top); b.) Viscosity of hydrogen-methane blends: ■ measurements by Kobayashi *et al*. (2007), ▬ Davidson (1993) model predictions, ▪▪▪ GasVLe model predictions (bottom).

Several methods have been proposed in the literature for calculating the viscosity of gas mixtures (Kreiger, 1951; Brokaw, 1968; Davidson 1993). The present work is based on the "simple and accurate" method presented in the US Bureau of Mines report by Davidson (1993), which takes as inputs the molecular masses and viscosities of the constituent gases. The model was coded into a spreadsheet and verified by comparing results to the helium-neon mixtures presented in the Davidson (1993) report[6]. It was then used to predict the measurements of Kobayashi *et al*. (2007) for hydrogen-methane blends and gave good agreement with the data (Figure 1b)[7]. Predictions from the GasVLe software[8] using the Wilke-Brokaw formula with the Dean-Stiel density correction (see Reid *et al*., 1977) are also shown in Figure 1b for comparison purposes. It is worth noting that the gas mixture viscosity does not decrease linearly from the methane viscosity to the hydrogen viscosity as the volume fraction of hydrogen is increased. Instead, the mixture viscosity remains nearly constant up to a hydrogen volume fraction of 70% v/v before decreasing to the hydrogen value.

Coward and Jones (1952) reported that the flammability limits of hydrogen-methane mixtures could be calculated fairly well using Le Chatelier's law (see Figure 2a). The flammable limit values used here for pure methane and hydrogen are taken from Coward and Jones (1952) and Zabetakis (1965), who gave the lower and upper limits for methane as 5.0% v/v and 15% v/v, and those for hydrogen as 4.0% v/v and 75% v/v. Other sources in the literature provide slightly different values. For example, the British Standard on explosive atmospheres, BS EN 80079-20-1 (BSI, 2019), quotes the lower and upper flammability limits for methane as 4.4% v/v and 17% v/v. These flammability limit values are all measured for upward-propagating flames in flame tubes. Higher concentrations of 9.0% v/v are needed to sustain downward-propagating flames of hydrogen. A detailed discussion of the characteristics of upward and downward propagating flames, together with data from several experimental tests, was presented by Coward and Jones (1952).

The ratio of the specific heat capacities ($\gamma = c_p/c_v$) is used to calculate the speed of sound in compressible gas mixtures and in formulae for choked and subsonic release rates (presented later in this report). The values of γ for pure methane and hydrogen are fairly similar (1.31 for methane and 1.41 for hydrogen at 15°C and 101,325 Pa)[9]. To determine the value of γ for methane-hydrogen mixtures, the specific heat capacities (c_p and c_v, in kJ/kg K) are calculated for methane-hydrogen mixtures from their mass-fraction weighted averages, and then γ is found from the ratio of these values. Results are presented in Figure 2b for three pressures (standard atmospheric pressure, 7 barg and 85 barg).

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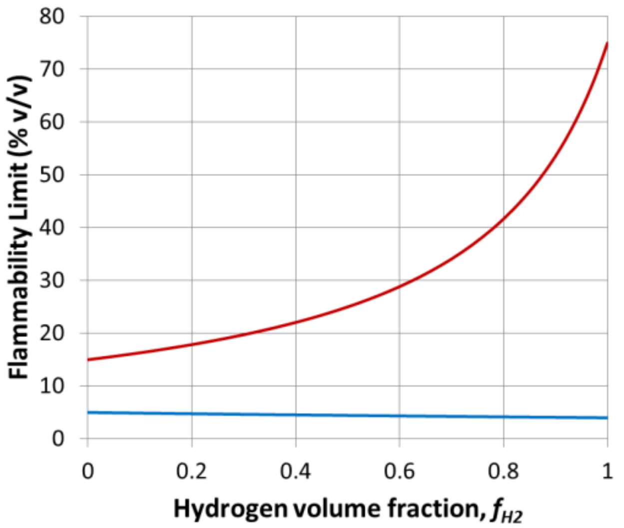
[6] *It appears that there may be a mistake in the units of viscosity presented in the Davidson (1993) report. For example, the pure helium dynamic viscosity is presented as 194 µPa·s (or 1.94 × 10^{-4} Pa·s), whereas the value given by the AirLiquide encyclopedia (https://encyclopedia.airliquide.com) is 1.94 × 10^{-4} Poise. Since 1 Poise is equivalent to 0.1 Pa·s, this equates to 1.94 × 10^{-5} Pa·s. Using the same viscosities as Davidson (1993), it was possible to reproduce the gas mixture viscosity graphs presented in his US Bureau of Mines report, which was taken as sufficient verification of the model for the purposes of the present work.*

[7] *The Kobayashi et al. (2007) measurements were taken at a temperature of 20 °C. Predictions from the Davidson (1993) model use pure component viscosities from https://encyclopedia.airliquide.com at the nearest temperature of 15 °C. GasVLe results are also for 15 °C.*

[8] *https://www.dnvgl.com/services/gasvle-8331, accessed 14 January 2020.*

[9] *Source: https://encyclopedia.airliquide.com, accessed 14 November 2019.*

a.)



b.)

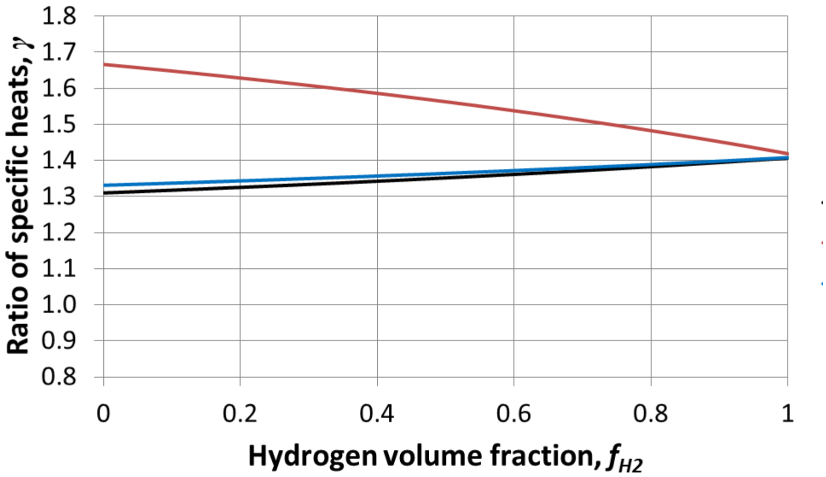


Figure 2 a.) Flammability limits calculated using Le Chatelier's law, — lower, — upper (top); b.) Ratio of specific heat capacities ($\gamma = c_p \, / \, c_v$) at three different pressures: — standard atmospheric pressure, — 7 barg, — 85 barg (bottom)

3 RELEASE RATES

Leaks of gas from pressurized pipes and vessels can occur in several different flow regimes. In order of increasing velocity and/or hole size these are: laminar flow, turbulent flow (incompressible), subsonic flow (compressible and turbulent) and choked flow (sonic, compressible and turbulent). These are considered below and for each regime the release rate of hydrogen relative to the release rate of methane is calculated.

3.1 LAMINAR FLOW

Laminar flow occurs at low speeds through small holes, producing smooth flow paths and little mixing. The dimensionless quantity that is used to characterise when laminar flow occurs is the Reynolds number, Re, defined as:

$$Re = \frac{\rho U D}{\mu} \tag{1}$$

where ρ is the density, U is the velocity, μ is the dynamic viscosity and D is the characteristic length (e.g. diameter of the hole through which the flow is passing). Laminar flow is produced in pipes below Reynolds numbers of around 2,000 (Massey, 1990). At higher Reynolds numbers of between 2,000 and 4,000 a transition occurs and for Reynolds numbers above 4,000 the flow is usually turbulent.

Swain and Swain (1992) examined the ratio of hydrogen to methane flow rates for laminar flow using Darcy's equation for the volumetric flow rate, $\dot{V}_{laminar}$:

$$\dot{V}_{laminar} = \frac{\Delta P \pi D^4}{128 L \mu} \tag{2}$$

where ΔP is the pressure drop between the inside of the pipe (or vessel) and the atmosphere, and L is the length of the hole. For the same supply pressure and temperature, and the same hole shape and size, they showed that the volumetric leak rate of hydrogen relative to methane is given by the ratio of the dynamic viscosities of the two gases:

$$\frac{\dot{V}_{H2}}{\dot{V}_{CH4}} = \frac{\mu_{CH4}}{\mu_{H2}} = \frac{1.1 \times 10^{-5}}{8.7 \times 10^{-6}} = 1.23 \tag{3}$$

This can be converted into a mass flow rate using the formula:

$$\frac{\dot{m}_{H2}}{\dot{m}_{CH4}} = \frac{M_{H2}}{M_{CH4}} \frac{\dot{V}_{H2}}{\dot{V}_{CH4}} = \frac{2}{16} 1.23 = 0.15 \tag{4}$$

The ratio of hydrogen to methane release rates can also be expressed in terms energy (or heat) fluxes of the two gases, using the heats of combustion (Q_{H2}= 285.8 MJ/kmol; Q_{CH4}= 890.8 MJ/kmol; CRC, 2008):

$$\frac{\dot{Q}_{H2}}{\dot{Q}_{CH4}} = \frac{Q_{H2}}{Q_{CH4}} \frac{\dot{V}_{H2}}{\dot{V}_{CH4}} = \frac{285.8}{890.8} 1.23 = 0.40 \tag{5}$$

The "gross" heats of combustion are used above, meaning that water produced in the combustion reaction is condensed into liquid, and the heat of combustion value accounts for the resulting release of latent heat. "Net" heats of combustion are sometimes quoted in the literature, for which the water in the combustion products is assumed to remain in the vapour state. The gross value is around 5% to 10% higher than the net heat of combustion for hydrocarbon gases such as methane, and around 15% higher than the net value for hydrogen. To calculate the heat released in a fire, it is more appropriate to use the net value, since water remains as vapour in that case. In addition, when assessing the heat load from thermal radiation from fires, it is necessary to take into account the combustion efficiency and radiative heat fraction. Such analysis is left to future work.

Further results are shown in Figure 3 for hydrogen-methane blends. The viscosity of the blended gas in these plots was found using the Davidson (1993) model presented earlier. A notable feature of the right-hand plot is that the volumetric flow rate of blended gas remains virtually the same as that of pure methane up to a hydrogen volume fraction of 70% v/v, due to the fact that the viscosity of the blended gas is similar to that of pure methane (see Figure 1b). This has important implications for projects like HyDeploy, which involve gas blends with 20% v/v hydrogen.

To gain some practical appreciation for when laminar flow occurs in leaking assets, it is possible to rearrange the expression for the volumetric flow rate (Equation 2) and the Reynolds number (Equation 1), to find the limiting (maximum) hole diameter for which the flow remains laminar:

$$D_{limit} = \left(\frac{32\, L\, Re\, \mu^2}{\Delta P\, \rho}\right)^{\frac{1}{3}} \tag{6}$$

Figure 4 presents two plots showing the behaviour of this equation for pure methane and pure hydrogen. The left-hand plot shows the limiting hole size for laminar flow as a function of pressure from 20 mbarg to 80 mbarg, assuming a path length of 5 mm. These values are relevant for leaks on above-ground assets in the Low Pressure (LP) natural gas network where the wall thickness is around 5 mm (e.g. the H21 above-ground leakage tests with cast-iron assets). The results show that hydrogen produces laminar flow in larger holes than methane. The right-hand graph in Figure 4 shows the limiting diameter for laminar flow as a function of path length for a pressure drop of 21 mbar. This is relevant to leaks from gas fittings and pipework at domestic supply pressures. For a flow path length of 1 mm (approximately the wall thickness of a gas pipe in a domestic setting), hydrogen gives laminar flow in holes up to 0.3 mm in diameter, as compared to holes up to 0.17 mm diameter for methane.

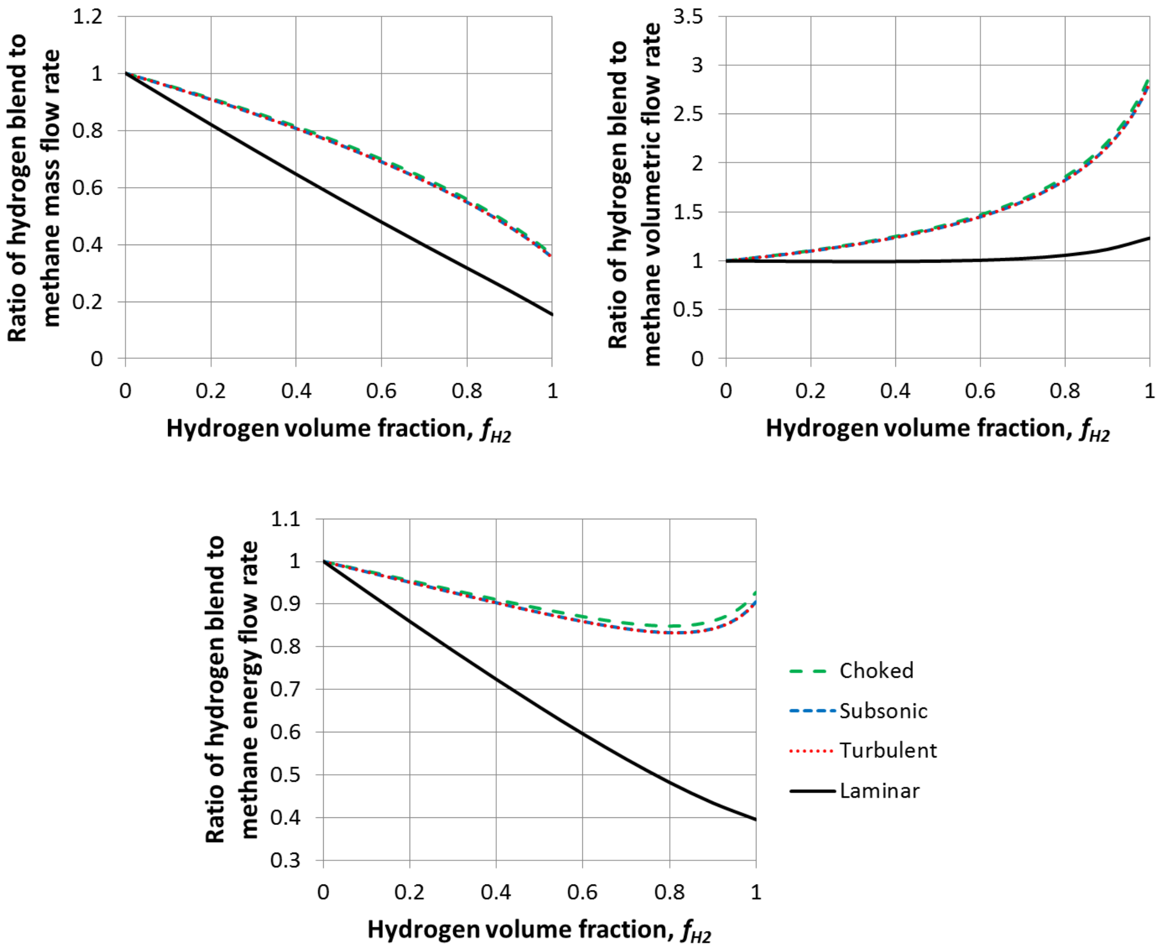


Figure 3 Ratio of hydrogen-methane blend to pure methane releases rates for choked, subsonic, turbulent and laminar flows in terms of the mass flux (left), volume flux (right) and energy flux (bottom).

Swain and Swain (1992) tested ten leaks in domestic gas pipes using methane, hydrogen and propane. Four leaks were fabricated by modifying home gas pipe fittings to simulate errors made during installation. The remaining six leaks involved gas pipes/fittings provided by a local (American) gas pipe company that had been removed from service due to excessive leakage rates. The holes in the first three tests were semi-circular in cross-section with diameters of 0.18 mm, 0.42 mm and 0.71 mm. Swain and Swain (1992) found that the majority of the leaks produced flow rates that indicated the flow was laminar at typical operating gas pressures.

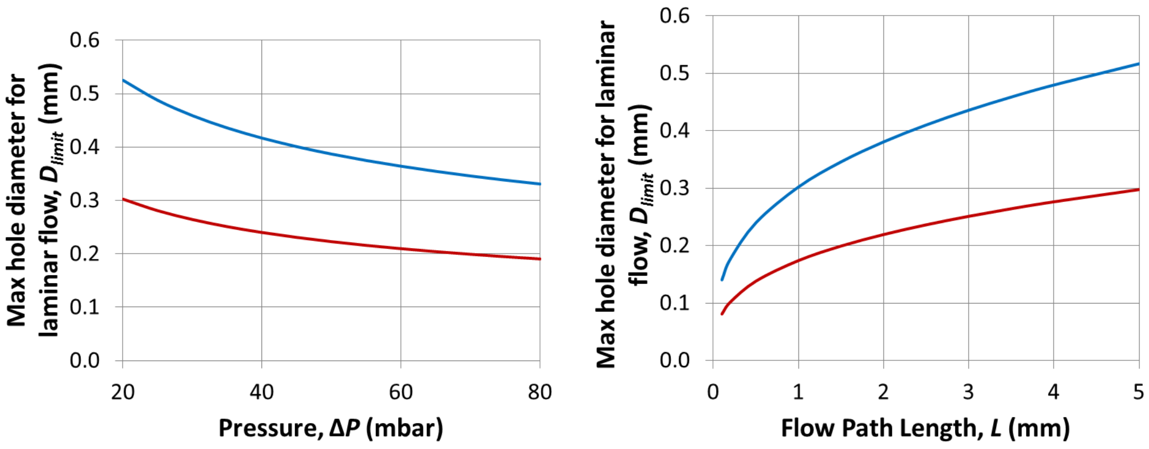


Figure 4 Maximum limiting hole diameters for laminar flow: ▬ hydrogen, ▬ methane. The left-hand plot assumes a flow path length of 5 mm, and the right-hand plot assumes a pressure of 21 mbar.

3.2 TURBULENT FLOW

Swain and Swain (1992) also analysed the ratio of hydrogen to methane leak rates for turbulent flow, where they modelled the volumetric flow rate using Darcy's equation, as follows:

$$\dot{V}_{turbulent} = 0.354\pi \frac{D^{2.5}\sqrt{\Delta P}}{\sqrt{fL\rho}} \tag{7}$$

where f is the friction factor, which is assumed to be constant for turbulent flow. Using this equation, they showed that the ratio of hydrogen to methane volumetric flow rates is equal to the inverse of the square-root of the gas densities (assuming that the hydrogen and methane leaks are through the same hole, at the same release temperature and pressure):

$$\frac{\dot{V}_{H2}}{\dot{V}_{CH4}} = \sqrt{\frac{\rho_{CH4}}{\rho_{H2}}} = \sqrt{\frac{M_{CH4}}{M_{H2}}} = \sqrt{\frac{16}{2}} = 2.8 \tag{8}$$

This result can be converted into mass and energy flow rates as before. The resulting ratio of the hydrogen to methane release rates in terms of mass is 0.35 and in terms of energy is 0.91. Results are presented in Figure 3 for hydrogen-methane blends. The hockey-stick shape to the energy release rate curve with a minima at a hydrogen volume fraction of around 0.8 is a consequence of combining the volumetric flow rate ratio (the curve sweeping upwards shown in Figure 3) with the heat of combustion of the hydrogen blend (a straight line that decreases linearly from the pure methane value of 890.8 MJ/kmol to the hydrogen value of 285.8 MJ/kmol as the hydrogen volume fraction increases from 0 to 1).

3.3 SUBSONIC FLOW

In the analysis presented by Swain and Swain (1992), gas-compressibility effects were not taken into account. This assumption is appropriate for low gas pressures (e.g. domestic gas pressures of 21 mbarg) but it may produce errors at higher pressures.

The critical pressure, P_c, is calculated as follows:

$$P_c = P_{atm}\left(\frac{2}{\gamma+1}\right)^{-\gamma/(\gamma-1)} \tag{9}$$

where P_{atm} is the atmospheric pressure and γ is the ratio of specific heats. The critical pressure, P_c, is 0.85 barg for pure methane and 0.91 barg for pure hydrogen. For pressures below the critical pressure, the flow is subsonic (not choked) and the mass flow rate of a compressible ideal gas can be calculated as follows (BSI, 2015):

$$\dot{m} = C_d A P \sqrt{\frac{M}{ZRT}\frac{2\gamma}{(\gamma-1)}\left[1-\left(\frac{P_{atm}}{P}\right)^{(\gamma-1)/\gamma}\right]}\left(\frac{P_{atm}}{P}\right)^{1/\gamma} \tag{10}$$

where C_d is the discharge coefficient, A is the cross-sectional area of the opening, P is the pressure inside the vessel or pipe, R is the universal gas constant (8,314 J kmol^{-1} K^{-1}) and Z is the compressibility correction factor, which takes a value of 1.0 for ideal gases.

Using this equation, the ratio of hydrogen to methane mass release rates is:

$$\frac{\dot{m}_{H2}}{\dot{m}_{CH4}} = C_{subsonic}\sqrt{\frac{M_{H2}}{M_{CH4}}} = \begin{cases} 1.000\sqrt{\dfrac{2}{16}} = 0.35 \quad \text{for } P = 21 \text{ mbarg} \\ 1.026\sqrt{\dfrac{2}{16}} = 0.36 \quad \text{for } P = 0.9 \text{ barg} \end{cases} \tag{11}$$

where $C_{subsonic}$ contains the terms dependent upon pressure and the ratio of specific heats. This varies between bounding values of $C_{subsonic}$ = 1.0 to 1.026 across the range of pressures from 21 mbarg to 0.9 barg, which gives ratios of hydrogen to methane mass flow rates of between 0.35 and 0.36, i.e. practically identical values to the value obtained previously for turbulent flow. In terms of volumetric flow rates (using Equation 4) the ratios are between 2.8 and 2.9, and in terms of energy flow rates (using Equation 5) the ratios are between 0.91 and 0.93. Results are presented in Figure 3 for hydrogen blends at a pressure of 21 mbarg. The plots show that subsonic releases exhibit practically the same behaviour as turbulent releases.

3.4 CHOKED FLOW

Choked flow is a limiting condition reached when the pressure in the pipe or vessel is above the critical pressure, P_c. The velocity of the gas at the orifice in this case is sonic (i.e. a Mach number of one). If the pressure is increased still higher, above P_c, the velocity of gas at the orifice remains fixed at the speed of sound, but the mass flow rate increases due to an increase in the density of the gas. In the UK gas distribution network, there are three pressure tiers: Low Pressure (LP) from 19 mbarg to 75 mbarg, Medium Pressure (MP) from 75 mbarg to 2 barg and Intermediate Pressure (IP) from 2 to 7 barg. Choked flow is therefore only relevant for leaks from MP and IP assets. Gas pressures in domestic properties are typically around 21 mbarg, and therefore leaks within homes will not behave as choked releases.

When the flow is choked, the mass flow rate is given by the following equation (BSI, 2015):

$$\dot{m} = C_d AP \sqrt{\gamma \frac{M}{ZRT} \left(\frac{2}{\gamma + 1}\right)^{(\gamma+1)/(\gamma-1)}} \qquad (12)$$

For the same leak conditions (i.e. the same hole size, discharge coefficient, pressure and temperature), the ratio of the hydrogen to methane mass flow rates is then:

$$\frac{\dot{m}_{H2}}{\dot{m}_{CH4}} = C_{choked} \sqrt{\frac{M_{H2}}{M_{CH4}}} = 1.025 \sqrt{\frac{2}{16}} = 0.36 \qquad (13)$$

The term C_{choked} in the above equation is a function of γ and is equal to 1.025 for the ratio of hydrogen to methane. The resulting ratio of mass flow rates is 0.36, which is practically the same as the value obtained previously for subsonic releases. In terms of volumetric flow rates, (using Equation 4) the ratio is 2.9, and in terms of energy flow rates (using Equation 5) the ratio is 0.93. Results for hydrogen blends are presented in Figure 3, and they show very similar behaviour to that obtained previously for turbulent and subsonic releases.

The expansion of a compressible gas from a pressurized vessel or pipe to atmospheric pressure causes a reduction in the gas temperature (and hence an increase in the gas density). This decrease in temperature is a function of the ratio of specific heat capacities of the gas. For subsonic releases, the relevant equation for the density at the source is given in BS EN 60079-10-1 (BSI, 2015), and for choked releases, the following expression is given by Ewan and Moodie (1986):

$$\rho_0 = \rho_g \left(\frac{\gamma + 1}{2}\right) \qquad (14)$$

where ρ_0 is the gas density at the source and ρ_g is the gas density at the upstream (stagnation) temperature in the vessel or pipe. Since γ is different for hydrogen and methane, the degree of cooling is different for the two gases. The results presented in Figure 3 do not take into account this difference in temperature, and instead the conversion from mass to volumetric flow rates has simply used the ratio of the molecular masses (as in Equation 4), which assumes that the hydrogen and methane temperatures are the same. Calculations have been performed which factor in the different densities given by the equation in BS EN 60079-10-1 and Equation 14, and the effect is very small. For both subsonic and choked releases, the resulting error in the ratio of hydrogen to methane volume flow rates is a maximum of 4% in relative terms (i.e. a change in the ratio $\dot{V}_{H2}/\dot{V}_{CH4}$ from 2.9 to 2.8).

Before concluding this section, it is worth noting that for turbulent, subsonic or choked releases, the above analysis has shown that the ratio of hydrogen to methane release rates can be estimated quickly (with an error of less than a few percent) from the square-root of the ratio of the molecular masses of the two gases, i.e.:

$$\frac{\dot{m}_{H2}}{\dot{m}_{CH4}} \approx \sqrt{\frac{M_{H2}}{M_{CH4}}} \quad ; \quad \frac{\dot{V}_{H2}}{\dot{V}_{CH4}} \approx \sqrt{\frac{M_{CH4}}{M_{H2}}} \qquad (15)$$

The ratio of hydrogen to methane release rates is given by a single set of curves shown in Figure 3. In future work, it would be useful to revisit this analysis using realistic natural gas compositions. Properties such as the ratio of specific heat capacities may differ, particularly at high pressures.

4 DISPERSION

4.1 JETS

Chen and Rodi (1980) provided the following expression for the decay of concentration with distance in vertical buoyant jets issuing from a round orifice:

$$y = k\left(\frac{\rho_0}{\rho_a}\right)^{\frac{1}{2}}\frac{D}{x} \tag{16}$$

where y is the concentration expressed as a mass fraction, k is a model constant, ρ_0 and ρ_a are the source gas density and ambient (air) density, D is the source diameter and x is the distance downstream from the source. A notable feature of this equation is that the concentration does not depend on the release velocity. Instead, the concentration at a given distance only depends on the source gas density and the diameter of the source. This behaviour is related to the entrainment of fresh air into the jet. Air entrainment rates are proportional to the centreline velocity of the jet (Ricou and Spalding, 1961). A faster jet releases more gas, but it also entrains air at a faster rate and these two effects balance each other out. Different values for the constant k are proposed in the literature, which may relate to different initial conditions (George, 1989) and a value of 5.4 from Chen and Rodi (1980) is often used. The dependence of concentration on the ratio (ρ_a/ρ_0) originates from the work of Ricou and Spalding (1961) who studied the entrainment of air into jets of air, hydrogen, propane and carbon dioxide. The fact that their work included hydrogen jets lends some support to the analysis presented here. Further background to Chen and Rodi's work is provided in the Appendix.

Equation 16 can be rearranged in terms of the distance x to the LFL concentration. The expression can then be used to assess the change in the distance to the LFL for hydrogen relative to methane, as follows:

$$\frac{x_{H2}}{x_{CH4}} = \left(\frac{\rho_{H2}}{\rho_{CH4}}\right)^{\frac{1}{2}}\frac{y_{CH4}}{y_{H2}} = \left(\frac{M_{H2}}{M_{CH4}}\right)^{\frac{1}{2}}\frac{y_{CH4}}{y_{H2}} = \left(\frac{2}{16}\right)^{\frac{1}{2}}\frac{2.8}{0.29} = 3.5 \tag{17}$$

where the LFL mass fractions for hydrogen and methane are y_{H2} = 0.29% w/w and y_{CH4} = 2.8% w/w. The above result shows that flammable hydrogen clouds will extend 3.5 times further than the equivalent flammable methane clouds in situations where there is a free unobstructed vertical jet release from the same round hole, at the same temperature and pressure. The result is insensitive to the pressure of the release, provided it is below the critical pressure (i.e. below around 0.85 barg).

The fact that flammable hydrogen jets are larger than the equivalent methane jets is not related to the fact that the release rate of hydrogen is 2.8 times greater than methane (for a turbulent release). As noted earlier, the release rate does not feature in the relevant equation for gas concentration (Equation 16). Instead, the larger flammable cloud for hydrogen is caused by the significant difference in density between the gas and the surrounding air. The jet momentum is reduced quickly in hydrogen jets, since the air density is so much higher than the hydrogen density. This loss in momentum means that air is entrained at a slower rate into hydrogen jets than into methane jets. Since less air is entrained, hydrogen jets dilute more slowly and gas concentrations remain above the LFL for longer, giving a larger distance to the LFL.

Above the critical pressure, gas releases are choked. The flow immediately downstream of the orifice features a series of expansion waves and shocks as the jet expands to reach atmospheric pressure. The behaviour of the jet downstream of the shocks resembles a subsonic jet produced by a larger source than the actual orifice. Models for this scenario using "pseudo" or "equivalent" source conditions have been developed by Birch *et al*. (1984, 1987) and Ewan and Moodie (1986) (see Molkov, 2015, for a recent review and Ruffin *et al.*, 1996, for further validation). Their models can be written in the following form for the mass fraction along the centreline of the jet:

$$y = k\left(\frac{\rho_0}{\rho_a}\right)^{\frac{1}{2}}\frac{D_{eff}}{x+a} \tag{18}$$

where D_{eff} is the effective diameter of the jet pseudo-source, and a is an offset distance from the orifice to the "virtual" origin of the jet. Birch *et al.* (1984, 1987) derived their equation for concentration in terms of the volume fraction, not mass fraction, but their equation can be converted into the above form, as shown in the Appendix. Birch *et al.* (1987) provided the following expression for the effective diameter, D_{eff}:

$$\frac{D_{eff}}{D} = C_D\sqrt{\left[\frac{P}{P_{atm}}\left(\frac{2}{\gamma+1}\right)^{\frac{1}{\gamma-1}}\frac{\gamma}{(\gamma C_D^2+1)}\right]} \tag{19}$$

where C_D is the discharge coefficient, P is the upstream pressure in the pipe or vessel and P_{atm} is the atmospheric pressure[10]. Birch *et al.* (1987) assumed a discharge coefficient of 1.0 and they also found that the concentration offset distance, a, was independent of the pressure and equal to 0.6 orifice diameters. This offset distance is small in comparison to the length of the flammable cloud and therefore in the analysis presented here it is ignored. Their model also assumed that the temperature of the gas at the pseudo-source is the same as the temperature of gas in the pipe or vessel (i.e. the density ρ_0 in Equation 18 is evaluated at the upstream temperature in the pipe or vessel).

It is possible to rearrange Equations 18 and 19 to express the distance, x, to a particular mass fraction, y, and from there derive the following equation for the distance to the LFL for hydrogen relative to methane for a choked release:

$$\frac{x_{H2}}{x_{CH4}} = \left(\frac{M_{H2}}{M_{CH4}}\right)^{\frac{1}{2}}\frac{y_{CH4}}{y_{H2}}\frac{f(\gamma_{H2})}{f(\gamma_{CH4})} = \left(\frac{2}{16}\right)^{\frac{1}{2}}\frac{2.8}{0.29}1.02 = 3.5 \tag{20}$$

The function $f(\gamma)$ in the above equation is the term on the right-hand side of Equation 19, without the pressures, which cancel since it is assumed the methane and hydrogen releases are from pipes or vessels at the same pressure. The ratio of specific heats changes relatively little between hydrogen and methane, and therefore the ratio of the two functions of hydrogen to methane, $f(\gamma_{H2})/f(\gamma_{CH4})$, is close to one. The analysis predicts that the distance to the LFL is 3.5 times larger for hydrogen than for methane, which is practically identical to the result obtained earlier for subsonic releases.

Ewan and Moodie (1986) used a different expression for the effective pseudo-source diameter, as follows:

$$\frac{D_{eff}}{D} = \left(\frac{P_e}{P_a}\right)^{\frac{1}{2}} \quad ; \quad P_e = P\left(\frac{2}{\gamma+1}\right)^{\frac{\gamma}{\gamma-1}} \tag{21}$$

where P_e is the exit pressure at the orifice. Their model assumed that the temperature of the gas at the pseudo-source was cooler than the upstream pressure due to expansion of the gas, and their equation for the resulting density of the gas was given earlier (Equation 14). Equations 14, 18 and 21 can be rearranged into the following expression for the ratio of the hydrogen to the methane distance to LFL:

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[10] *Birch et al. (1987) appear to have made two typographical errors in their paper when presenting this equation. Firstly the equals sign = was written as +. Secondly, the γ on the numerator of the final term was written as 1.*

$$\frac{x_{H2}}{x_{CH4}} = \left[\frac{M_{H2}}{M_{CH4}}\frac{(\gamma_{H2}+1)}{(\gamma_{CH4}+1)}\right]^{\frac{1}{2}}\frac{y_{CH4}}{y_{H2}}\left(\frac{2}{\gamma_{H2}+1}\right)^{\frac{\gamma_{H2}}{\gamma_{H2}-1}}\left(\frac{2}{\gamma_{CH4}+1}\right)^{-\frac{\gamma_{CH4}}{\gamma_{CH4}-1}} = 3.4 \qquad (22)$$

Inserting appropriate values for M and γ into the above expression gives the result that the distance to the LFL for hydrogen is 3.4 times that of methane, i.e. similar to the values obtained previously using the Birch *et al*. (1987) pseudo-source for choked releases, and for the Chen and Rodi (1980) correlation for subsonic releases.

The values quoted above are based on evaluating γ at a pressure of 7 barg and a temperature of 15 °C. If, alternatively, it is evaluated at a higher pressure of 85 barg, the values of γ for hydrogen and methane change slightly (see Figure 2b). Equation 20 then gives a ratio $(x_{H2}\ /\ x_{CH4})$ of 3.3 and Equation 22 gives a ratio of 3.6.

The distance to a concentration of 50% LFL is often used instead of 100% LFL in area classification to take into account the fact that concentrations in jets and plumes fluctuate over time due to turbulence, and therefore concentrations at times exceed the predicted mean concentrations (Webber, 2002). The results presented above are for the distance to 100% LFL. Since the equations are expressed in terms of the ratio of the mass fractions (y_{CH4}/y_{H2}), and not the volume fractions, the results for the ratio of the distances $(x_{H2}\ /\ x_{CH4}\ )$ are around 1% larger for 50% LFL (i.e. for the subsonic case, the ratio is 3.50 instead of 3.47). Figure 5 compares the ratio of predicted distances to the 50% LEL across the full range of hydrogen blends. The results show that choked releases behave similarly to subsonic releases across the range of gas compositions.

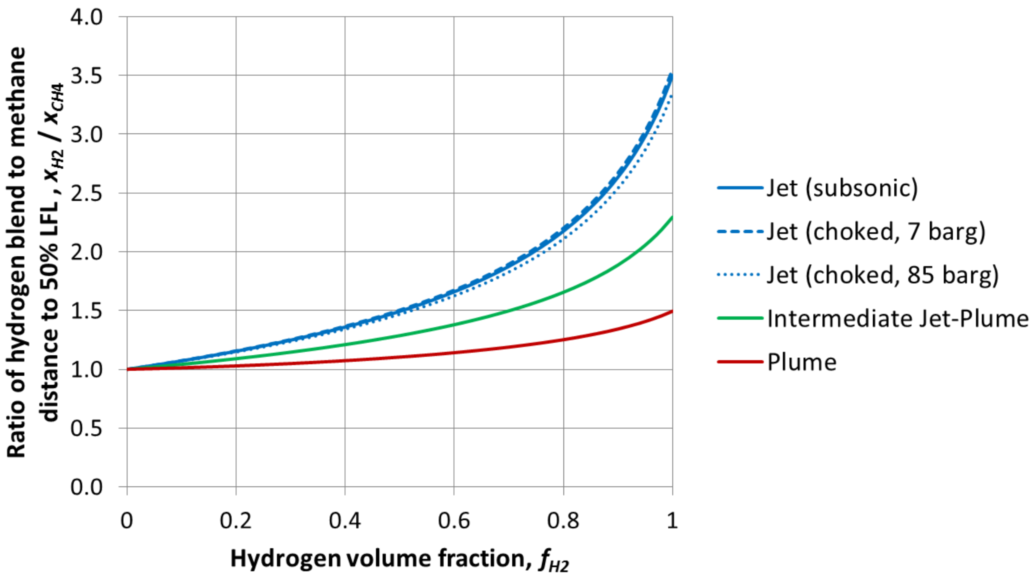

Figure 5 Ratio of the distance to 50% LFL for hydrogen blends relative to methane $(x_{H2}/x_{CH4}\ )$ in free vertical turbulent round jets, plumes and intermediate jet-plumes. The results for the distance to 100% LFL are the same to two significant figures and appear nearly identical to those shown here for 50% LFL. The choked gas releases shown here are calculated using the Birch *et al*. (1987) pseudo-source but results are practically identical using the Ewan & Moodie (1986) model.

4.2 INTERMEDIATE JET-PLUME

Chen and Rodi (1980) also provided correlations for the decay of concentration in releases where buoyancy forces are more significant (i.e. where gas disperses more as a plume than a jet). For the intermediate regime between jet and plume, they gave the following correlation:

$$C^* = 4.4 Fr^{\frac{1}{8}} \left(\frac{\rho_0}{\rho_a}\right)^{-\frac{7}{16}} \left(\frac{x}{D}\right)^{-\frac{5}{4}} \tag{23}$$

where C^* is the volume fraction (not the mass fraction as used earlier in the jet correlation – see Appendix) and the constant of 4.4 is taken from Smith *et al*. (1986)[11]. The term Fr in the above equation is the Froude number, i.e. the ratio of inertial to buoyancy forces, which is calculated[12] from:

$$Fr = \frac{\rho_0 U_0^2}{gD(\rho_a - \rho_0)} \tag{24}$$

where U_0 is the release velocity and g is the acceleration due to gravity (9.81 m/s^2). Following a similar approach to that used above for jets, the equation can be rearranged to express the ratio of the distance to the LFL for hydrogen relative to methane:

$$\begin{aligned} \frac{x_{H2}}{x_{CH4}} &= \left(\frac{C^*_{CH4}}{C^*_{H2}}\right)^{\frac{4}{5}} \left(\frac{U_{H2}}{U_{CH4}}\right)^{\frac{1}{5}} \left(\frac{M_{air} - M_{CH4}}{M_{air} - M_{H2}}\right)^{\frac{1}{10}} \left(\frac{M_{CH4}}{M_{H2}}\right)^{\frac{1}{4}} \\ &= \left(\frac{0.05}{0.04}\right)^{\frac{4}{5}} (2.8)^{\frac{1}{5}} \left(\frac{29-16}{29-2}\right)^{\frac{1}{10}} \left(\frac{16}{2}\right)^{\frac{1}{4}} = 2.3 \end{aligned} \tag{25}$$

In the above equation, the ratio of the hydrogen to methane initial velocities ($U_{H2} \,/\, U_{CH4}$) is 2.8 for turbulent releases (c.f. Equation 8 – assuming the hole size is the same for both the hydrogen and methane releases). The hydrogen and methane LFL volume fractions are taken to be $C^*_{H2} = 0.04$ v/v and $C^*_{CH4} = 0.05$ v/v (see Figure 2a). The equation shows that flammable hydrogen clouds will extend 2.3 times further than the equivalent flammable methane clouds in situations where the release is in the intermediate jet-plume regime. Further results for methane blends are presented in Figure 5.

4.3 PLUMES

Chen and Rodi (1980) gave the following correlation for the concentration decay along the centreline of vertical turbulent plumes, where the dispersion behaviour is dominated by buoyancy effects:

$$C^* = 9.35 Fr^{\frac{1}{3}} \left(\frac{\rho_0}{\rho_a}\right)^{-\frac{1}{3}} \left(\frac{x}{D}\right)^{-\frac{5}{3}} \tag{26}$$

which can be rearranged as before to give:

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[11] *Chen and Rodi (1980) presented a different value of 0.44, which may have been a typographical mistake (for further discussion, see Gant et al., 2011). In the analysis presented here, the constant cancels from the equation and therefore this ambiguity does not affect the findings.*

[12] *Other authors often define the Froude number as the square-root of the Froude number given here, as defined by Chen and Rodi (1980).*

$$\frac{x_{H2}}{x_{CH4}} = \left(\frac{C^*_{CH4}}{C^*_{H2}}\right)^{\frac{3}{5}} \left(\frac{U_{H2}}{U_{CH4}}\right)^{\frac{2}{5}} \left(\frac{M_{air} - M_{CH4}}{M_{air} - M_{H2}}\right)^{\frac{1}{5}} = \left(\frac{5.0}{4.0}\right)^{\frac{3}{5}} (2.8)^{\frac{2}{5}} \left(\frac{29 - 16}{29 - 2}\right)^{\frac{1}{5}} = 1.5 \qquad (27)$$

This shows that flammable hydrogen clouds will extend 1.5 times further than the equivalent flammable methane clouds in situations where the release is in the pure buoyancy-dominated plume regime.

4.4 WHEN DO JETS BECOME PLUMES?

Chen and Rodi (1980) presented the following parameter to determine the extent of the jet and plume regions:

$$B = Fr^{-\frac{1}{2}} \left(\frac{\rho_0}{\rho_a}\right)^{-\frac{1}{4}} \frac{x}{D} \qquad (28)$$

where:

$B < 0.5$	the flow is a momentum-dominated jet
$0.5 < B < 5.0$	the flow is in an intermediate state between jet and plume
$B > 5.0$	the flow is a buoyancy-dominated plume

From this equation, it can be seen that the transition from momentum-dominated (jet) to buoyancy-dominated (plume) behaviour occurs nearer the source if the density difference ($\rho_a - \rho_0$) is increased, the initial velocity (U_0) is decreased or the source diameter (D) is decreased.

Equation 28 can be combined with the equations presented earlier for jets and plumes, and rearranged to define the boundary between jet and plume behaviour at the point where the gas concentration reaches either 100% LFL or 50% LFL. Results from this analysis are presented in Figure 6 for methane and hydrogen in terms of the upstream pressure and hole size. The results show that hydrogen exhibits a greater tendency towards plume behaviour than methane, as expected from its lower density. The chevron shape to the three flow regions (jet, intermediate and plume) is due to the transition from subsonic to choked flow at the critical pressure (0.85 barg for methane and 0.91 barg for hydrogen). Below the critical pressure, when the release is subsonic, an increase in the pressure causes an increase in the release velocity and hence a higher Froude number (i.e. a greater tendency for the release to be jet-dominated). Above the critical pressure, when the release is choked, the velocity is capped at the speed of sound and an increase in the pressure produces a larger pseudo-source, which changes the behaviour. The Ewan and Moodie (1986) and Birch *et al*. (1987) models produce slightly different results when the flow is choked, as shown by the red and blue lines above the critical pressure. The coloured regions shown in the plot to distinguish between jet, intermediate and plume regions average between the results of these two choked-flow models.

The reason for producing Figure 6 is to help the reader assess which flow regime applies for their case of interest (in terms of pressure and hole size). This knowledge of the flow regime can then be used in conjunction with Figure 5 to identify how large a flammable cloud of hydrogen-blended gas will be produced, relative to the equivalent cloud of methane.

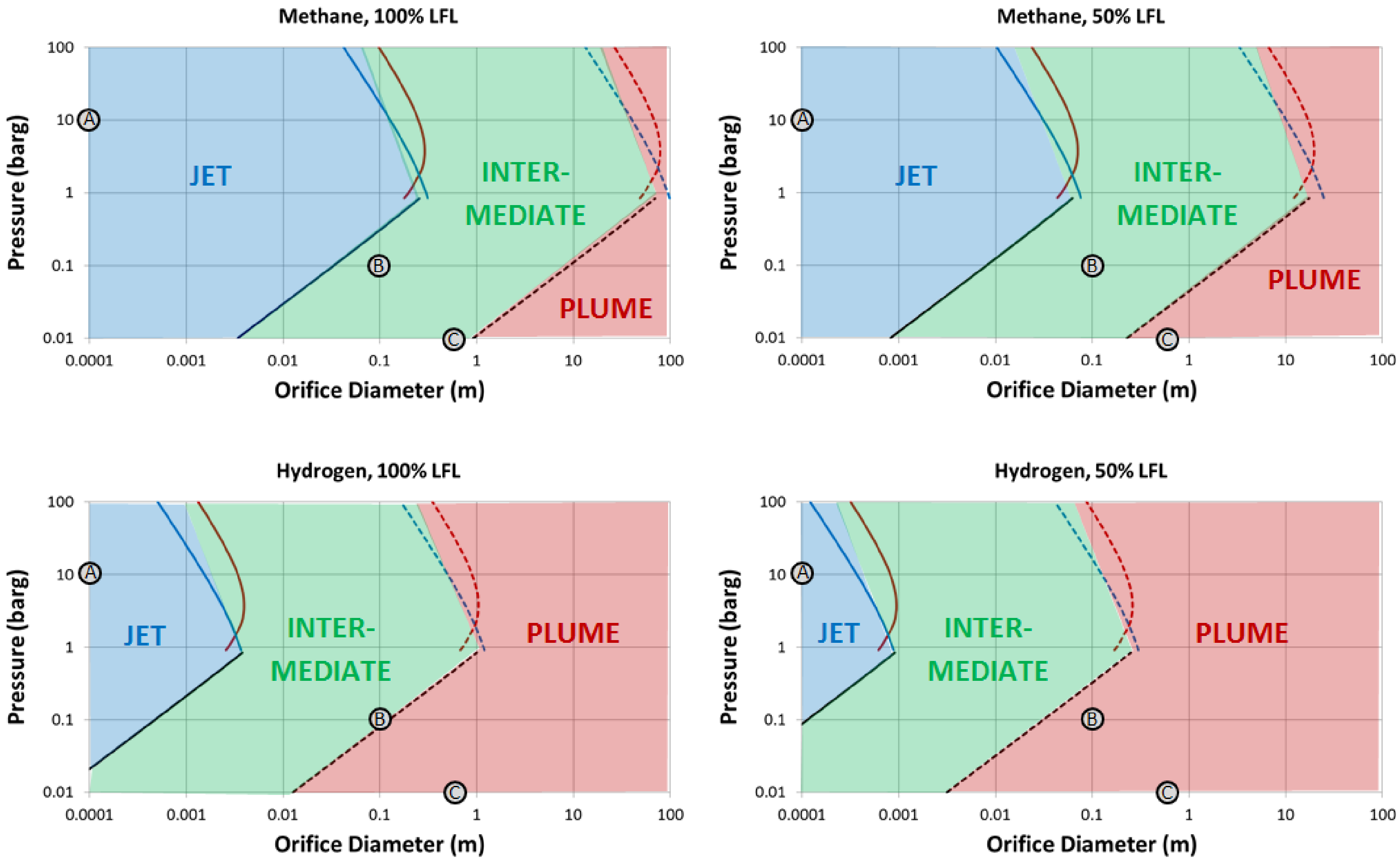

Figure 6 Jet, intermediate and plume regions for round buoyant jet releases of methane (top) and hydrogen (bottom) in air. Plots on the left are for the 100% LFL and on the right for 50% LFL. Lines mark the boundary between the regions. Solid lines are for the jet-to-intermediate boundary and broken lines for the intermediate-to-plume boundary. Line colours are: ▬ subsonic, ▬ choked (Ewan and Moodie, 1986), ▬ choked (Birch *et al.*, 1987). Symbols marked A, B and C are three scenarios modelled in the Quadvent-2 software.

4.5 QUADVENT-2 SOFTWARE COMPARISON

As a check on the previous analysis, calculations were performed using the Quadvent-2 software[13]. This uses an integral-modelling approach to simulate the dispersion of jets and plumes, both in the open air or in ventilated rooms (Webber *et al*., 2011, 2020). It uses the entrainment model of Ricou and Spalding (1961), but does not rely upon the empirical correlations presented by Chen and Rodi (1980). Three release conditions were simulated, shown in Figure 6 as circular symbols A, B and C, which were chosen to be in the jet, intermediate and plume flow regimes, respectively. Table 1 compares the results from Quadvent-2 to those predicted from the Chen and Rodi (1980) analysis presented above. In some cases, such as Condition B (an orifice diameter of 0.1 m and pressure of 0.1 barg), the hydrogen release is predicted to be in the plume regime whilst the methane release is in the intermediate jet-plume regime (at the point where the concentrations reach 50% LFL). The above analysis predicts that the ratio (x_{H2} / x_{CH4}) will be 1.5 in the former case and 2.3 in the latter, and so the Chen and Rodi (1980) result is presented in the table as a range between these values.

There is generally good agreement shown in Table 1 between the Quadvent-2 results and those obtained using the jet and plume correlations from Chen and Rodi (1980). For the jet release (Condition A), Quadvent-2 predicted the flammable hydrogen jet to extend 3.6 times further than the equivalent methane jet, and the Chen and Rodi analysis produces a value of 3.5. For the intermediate jet-plume case (Condition B), Quadvent-2 predicted values of (x_{H2} / x_{CH4}) to be 2.9 and 2.4 for the distance to 100% LFL and 50% LFL, respectively, whereas Chen and Rodi's correlations produced a value of 2.3 and a range between 2.3 (intermediate jet-plume) and 1.5 (plume). For the final plume case (Condition C), Quadvent-2 predicted (x_{H2} / x_{CH4}) values of 1.9 and 1.7, whilst the Chen and Rodi values were again in the range 2.3 to 1.5.

The benefit of the analysis in Sections 4.1 to 4.4 over Quadvent-2 is that it shows how the flammable cloud size is affected by the addition of hydrogen across the full range of conditions from zero to 100% hydrogen (see Figure 5). The correlations explain how the flow changes with hole size and pressure, rather than just providing spot values for certain scenarios. The dispersion behaviour is also characterised for the upper and lower bounding cases of momentum-driven jets and buoyancy-dominated plumes. In principle, these results could be obtained from Quadvent-2, but it would involve several hundred individual Quadvent-2 calculations to produce equivalent plots showing the trends in model behaviour.

The increase in the size of flammable clouds for hydrogen as compared to methane has been observed experimentally in work undertaken for the EMERGE project[14] at the French laboratory, INERIS. Chaineaux and Schumann (1995) undertook experiments using a 5 m^3 vessel that was initially pressurised to 40 bar and measured concentrations in free-jets of methane, propane and hydrogen using discharge orifices ranging from 25 mm to 150 mm in diameter. They found that the distance to LFL for hydrogen was around twice the distance for methane. The flammable cloud volume was also calculated to be approximately ten times larger for hydrogen.

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[13] *https://www.hsl.gov.uk/publications-and-products/quadvent-2, accessed 24 September 2019.*

[14] *Extended Modelling and Experimental Research into Gas Explosions (EMERGE)*

Table 1 Comparison of Quadvent-2 predictions to the Chen and Rodi (1980) jet and plume correlations in terms of the ratio of the distances to LFL for hydrogen relative to methane (x_{H2} / x_{CH4})

	A: Jet	**B: Intermediate Jet-Plume**	**C: Plume**
Orifice diameter (m)	0.0001	0.1	0.5
Pressure (barg)	10	0.1	0.01
Release Rate (kg/s)			
Quadvent-2 Hydrogen ($\dot{m}_{H2}$)	5.5×10^{-6}	0.32	2.6
Quadvent-2 Methane ($\dot{m}_{CH4}$)	5.5×10^{-5}	0.90	7.2
Quadvent-2 ($\dot{m}_{H2}/\dot{m}_{CH4}$)	0.36	0.36	0.35
Predicted ($\dot{m}_{H2}/\dot{m}_{CH4}$), Equations 11 and 13	0.36	0.36	0.35
Distance to 100% LFL (m)			
Quadvent-2 Hydrogen (x_{H2})	0.11	34	93
Quadvent-2 Methane (x_{CH4})	0.030	12	49
Quadvent-2 (x_{H2}/x_{CH4})	3.6	2.9	1.9
Predicted (x_{H2}/x_{CH4}), Equations 20, 25 and 27	3.5	2.3	2.3 – 1.5
Distance to 50% LFL (m)			
Quadvent-2 Hydrogen (x_{H2})	0.22	57	146
Quadvent-2 Methane (x_{CH4})	0.062	23	84
Quadvent-2 (x_{H2}/x_{CH4})	3.6	2.4	1.7
Predicted (x_{H2}/x_{CH4}), Equations 20, 25 and 27	3.5	2.3 – 1.5	1.5

4.6 GAS ACCUMULATION

To investigate the build-up of gas in enclosed spaces, a modified version of the model developed by Lowesmith *et al*. (2009) has been investigated. This model simulates a jet release into a room and predicts the build-up over time of a stratified layer of buoyant gas near the ceiling. The enclosure has upper and lower ventilation openings in the walls through which gas and/or air can flow. In zero-wind conditions, the flow of air through the lower ventilation opening into the room is driven by the buoyancy of gas in the stratified layer, which forces itself out of the upper opening. The model was originally developed as part of the NaturalHy project by Lowesmith *et al*. (2009) and has been coded up independently by HSE. Further details of this work, which has been undertaken in support of the HyDeploy-2 project, will be published in due course.

The main modifications to the original Lowesmith *et al*. (2009) model by HSE consisted of simplifications to fix the height of the buoyant gas layer in the model, and to remove the jet sub-model. The modified model assumes that the gas is released at the mid-height of the enclosure and that it becomes fully-mixed in the upper half of the space (i.e. immediately above the release point). Lowesmith *et al*. used a turbulent jet model to predict the initial dilution of the gas, but in the present model this is not used and instead the concentration in the stratified layer is calculated from fully mixing the release rate of gas and the inflow of fresh air. These simplifications were made because the focus of the present work is to examine the gas tightness testing aspects of the IGE/UP/1 procedure (see below). The release rates are very low in this case (i.e. laminar) and it is necessary to consider small enclosures, such as metering boxes. It was considered inappropriate to use the turbulent jet model to simulate these small laminar releases. The modelling approach was guided by the British Gas work documented in the book by Harris (1983), which was based on an extensive programme of gas release experiments.

5 EXAMPLE APPLICATION TO IGE/UP/1

To illustrate how the work presented above can be applied in practice to the UK gas network, the IGE/UP/1 utilization procedure (IGEM, 2005) has been examined. The scope of this procedure is strength testing, tightness testing and direct purging of industrial and commercial gas installations. As part of the gas tightness testing process, the procedure introduces the concept of the Maximum Permitted Leak Rate (MPLR) of gas, which is the maximum flow rate of gas an installation is allowed to leak when the system is at the operating pressure. For new installations, the MPLR is defined on the basis of an energy release rate of 0.054 MJ/hr, which for natural gas equates to a volumetric flow rate of 0.0014 m^3/hr. Different MPLR values are used for existing installations, depending upon the volume of the space enclosing the leak and the degree of ventilation.

Based on the work presented earlier in this report, the following questions are addressed:

1. Is a leak of gas at the MPLR laminar or turbulent?

2. For an installation with an existing natural gas leak equal to the MPLR, how would the leak rate change if the gas was switched to hydrogen (or a hydrogen-methane blend)? What would be the implications in terms of flammable cloud size?

3. The IGE/UP/1 procedure currently calculates the MPLR for different gases based on equivalent energy content (in MJ/hr). What would be the MPLR for hydrogen using this approach? What would be the implications in terms of the flammable cloud size?

To answer the first question: if the leak of gas is laminar, the flow rate will be governed by Equation 2, and if it is turbulent then the equations for turbulent or subsonic flow could be used (Equations 7 or 10). Using first the laminar flow equation, it is necessary to specify the length of the hole, L. Low pressure gas pipe wall thicknesses typically vary from 0.6 to 1.0 mm. The defect in the pipework/fittings producing the leak may not run straight through (perpendicular to) the pipe wall. Taking L = 1 mm as a starting point for the calculation, Equation 2 gives the equivalent hole size as 0.095 mm for a supply pressure of 21 mbarg. Assuming the gas in the pipework is at a temperature of 15 °C, the density of the methane at the orifice is ρ_0 = 0.68 kg/m^3 and the dynamic viscosity[15] of the gas is μ = 1.07 ×10^{-5} Pa.s, the calculated Reynolds number (Equation 1) is around 330 (see Table 2), i.e. it is well below the transition Reynolds number of 2,000, which therefore indicates that the flow of methane is laminar. Figure 4 showed that if the gas is switched from methane to hydrogen and the flow is laminar for methane, then it will also be laminar for hydrogen. This analysis assumes that all of the gas leaks through a single, circular hole. If the gas leaks through a slot or through multiple smaller holes, then these too will be laminar since the characteristic dimension D in the Reynolds number (Equation 1) will be smaller.

Moving onto the second question, if the gas was switched from methane to hydrogen and the permitted hole size was unchanged (i.e. using the hole size calculated previously for methane of 0.095 mm), then it is possible to determine the flow rate of hydrogen blends using the laminar flow equation (Equation 2). For pure hydrogen, the volumetric flow is 1.23 times higher than the flow rate of methane, i.e. 1.23 × 0.0014 = 0.0017 m^3/hr. The release rates for 20% and 50% hydrogen blends are unchanged (i.e. 0.0014 m^3/hr). These release rates are summarised in Table 3 under the heading “Scenario I”.

[15] *Values taken from the Air Liquide online encyclopaedia: https://encyclopedia.airliquide.com, accessed 25 November 2019.*

Table 2 IGE/UP/1 methane calculations for new installations and existing installations in Area Type A

- Methane MPLR volumetric flow rate = 0.0014 m^3/hr
- Laminar flow calculation (Equation 2)
  - Methane MPLR hole diameter = 0.095 mm
  - Methane MPLR Reynolds number = 330
- Subsonic flow calculation (Equation 10)
  - Methane MPLR hole diameter = 0.080 mm
  - Methane MPLR Reynolds number = 395

To examine the implications of the change in flow rates on the flammable cloud size, the gas accumulation model discussed in Section 4.5 was used. The scenario modelled consisted of a leak into a small enclosure such as an internal cupboard housing a gas meter, with dimensions (height, width and depth) of 1.0 m, 1.0 m and 0.5 m, respectively. The cupboard was assumed to have no designed ventilation openings but have cracks around the top and bottom of the door, and these cracks were assumed to span the width of the cupboard (1.0 m). As a first step, calculations were performed assuming a crack width of 1 mm around the door (i.e. an opening area of 1.0 × 0.001 m, at the top and bottom of the cupboard). Results are presented in Figure 7 for the build-up over time of gas in the top half of the cupboard for four different gases: pure methane, two blends of 20% and 50% hydrogen in methane, and pure hydrogen. The results show that in all cases the concentrations are well below the LFL. The 20% and 50% hydrogen releases give practically identical concentrations (as a percentage of LFL) to pure methane. The release rates used in these calculations for the blended gases are given in Table 3.

Table 3 Hydrogen-blend calculations in support of IGE/UP/1

	Methane	**20% Hydrogen**	**50% Hydrogen**	**100% Hydrogen**
Relative molecular mass (kg/kmol)	16.043	13.2	9.0	2.016
Lower flammability limit (% v/v)	5.0	4.8	4.4	4.0
Gross heat of combustion (MJ/m^3)	37.7	32.6	24.9	12.1
Scenario I: Volumetric flow rate for the hole diameter calculated in Table 2 for the methane MPLR assuming laminar flow (m^3/hr)	0.0014	0.0014	0.0014	0.0017
Scenario II: Volumetric flow rate that gives an energy flow rate of 0.054 MJ/hr (m^3/hr)	0.0014	0.0017	0.0022	0.0045
Scenario III: Volumetric flow rate set equal to the current natural gas value of 0.0014 m^3/hr	0.0014	0.0014	0.0014	0.0014

As a quick check on these calculations, Harris (1983) presented the following correlation for the minimum area of an opening needed to keep natural gas concentrations to "acceptable" levels in an enclosure:

$$A_b = \frac{1350\dot{V}_g}{\sqrt{H}} = \frac{1350\left(\frac{0.0014}{3600}\right)}{\sqrt{1}} = 0.0005\ m^2 \tag{29}$$

where $\dot{V}_g$ is the volume flow rate of gas and H is the vertical spacing between the upper and lower ventilation openings. The model assumes the flow is driven by the buoyancy of the gas and the openings are at the top and bottom of the enclosure. It predicts an opening area of 0.0005 m^2 for the MPLR flow rate of 0.0014 m^3/hr, and if this area is distributed across the width of the enclosure, it equates to a crack width of 0.5 mm. The result therefore confirms the model calculations presented in Figure 7, i.e. that concentrations with a crack width of 1 mm should be well below the LFL.

The gas accumulation model was then used to simulate the same cupboard with a smaller 0.05 mm crack around the door, which was chosen to be sufficiently small to give concentrations close to the LFL. The results again showed that the concentrations remained below the LFL, with the 20% and 50% hydrogen cases again giving similar results to methane in terms of the percentage of LFL. For the pure hydrogen release, the steady state concentration was higher than the methane case. The results presented in Figure 7 imply that the risks of forming flammable clouds due to small leaks at or below the MPLR are the same for the 20% and 50% blends as they are for natural gas, which is an important finding in the context of the HyDeploy project.

To address the third question, the IGE/UP/1 methodology was used to calculate the flow rates of 20%, 50% and 100% hydrogen blends necessary to achieve an energy flow rate of 0.054 MJ/hr. These results are presented in Table 3, where they are referred to as Scenario II. Gas accumulation calculations were then performed for the same scenario of a gas leak in a 1.0 × 1.0 × 0.5 m cupboard considered previously and the results are presented in Figure 8 as dashed lines. For the cupboard with 1 mm wide openings, the concentrations increased as the hydrogen content increased, but in all cases the steady-state concentrations were below the LFL. In the cupboard with a smaller crack width of 0.05 mm, the gas concentrations rose above the LFL for the 50% hydrogen blend and for the pure hydrogen release.

The results from this analysis suggest that the method used by IGE/UP/1 to define the MPLR for different gases would lead to an increased risk of producing flammable clouds for hydrogen blends. The low energy density of hydrogen per unit volume means that the MPLR volumetric flow rate is 3.1 times higher for pure hydrogen than it is for natural gas (0.0045 m^3/hr versus 0.0014 m^3/hr). In addition to the increased flow rate of gas, the LFL is also lower for hydrogen than natural gas, and the combined effects mean that hydrogen will be more likely to produce a flammable cloud than the current situation with natural gas.

A possible solution to this issue could be to define the MPLR for hydrogen blends and 100% hydrogen to be the same as the current MPLR for natural gas in volumetric terms, i.e. 0.0014 m^3/hr for new installations or existing installations with Area Type A (insufficient ventilation). This is referred to as Scenario III in Table 3. Results are presented in Figure 9 for the 20%, 50% and 100% hydrogen blends with the leak rate in all cases of 0.0014 m^3/hr. The gas accumulation model predicts practically identical results in terms of percentage LFL. In terms of gas concentration (in % v/v), the hydrogen blends produce lower concentrations than pure methane – i.e. the increase in buoyancy produces an increase in the ventilation rate, which dilutes the gas to a lower concentration. This is balanced by the lower LFL for the hydrogen blends so that, overall, the gas concentration as a percentage of LFL appears nearly identical for the four different gases.

This analysis has been performed assuming the pressure is the same for methane and hydrogen blends. In reality, there may be a greater drop in pressure along the pipework from the gas meter to equipment with hydrogen blends, due to the need to supply a higher volumetric flow rate of gas to the equipment for it to achieve the same heat output. This drop in pressure would only apply when the equipment was in operation, drawing gas along the pipe. Assuming that the pressure at the meter was the same for all gases, the effect of the higher pressure drop would be to reduce the leak rate for hydrogen blends. The result of analysis presented above should therefore be conservative, but it may be useful to investigate this matter further.

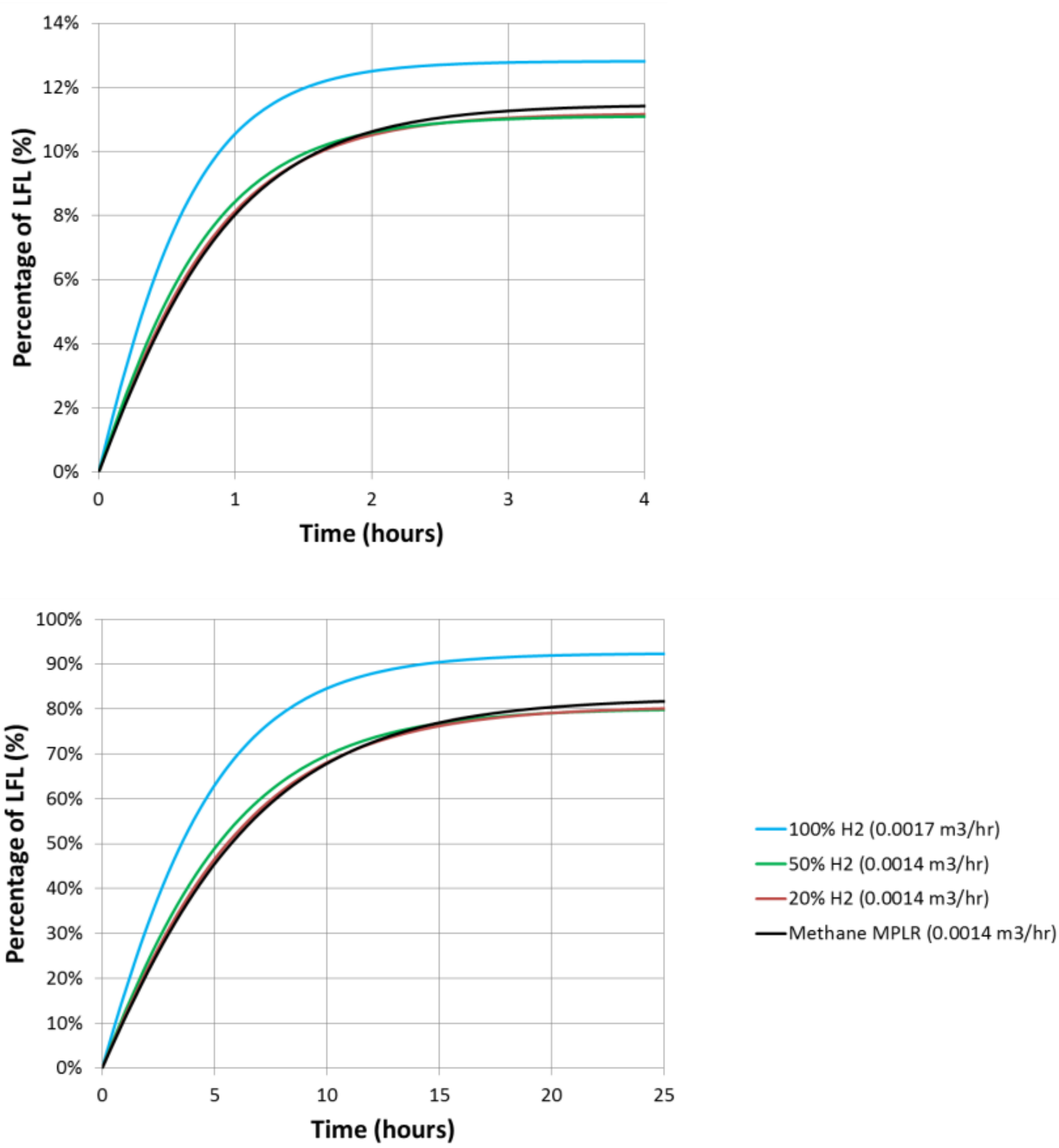

Figure 7 Predicted concentrations in a 1.0 × 1.0 × 0.5 m enclosure with ventilation openings top and bottom that are 1.0 m across and have a width of either 1 mm (top) or 0.05 mm (bottom). Four gas compositions are tested, as given in Table 3. Solid lines used flow rates calculated with a hole diameter of 0.095 mm and pressure of 21 mbarg, which gives the MPLR flow rate of 0.0014 m^3/hr for methane (Scenario I).

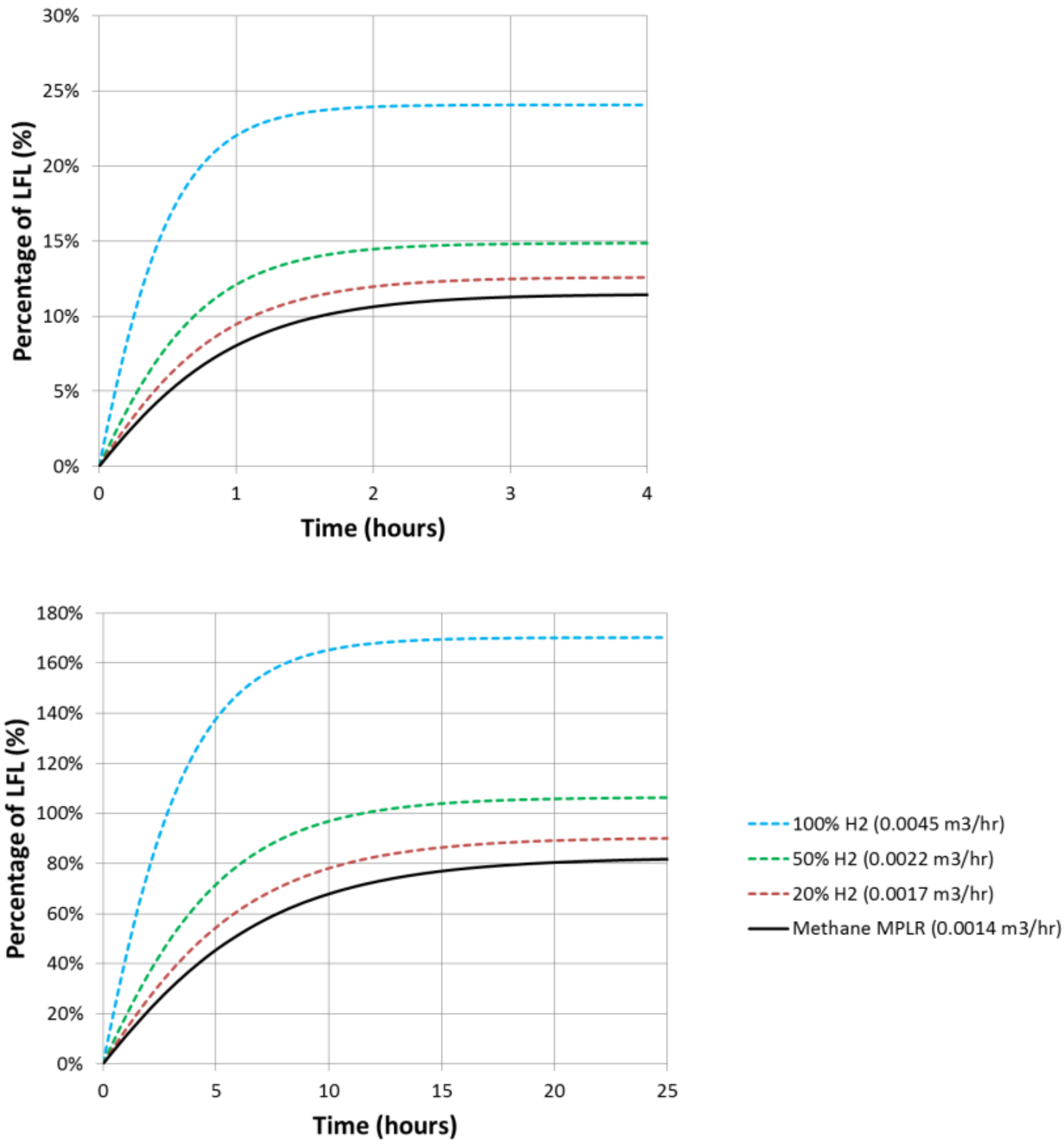

Figure 8 Predicted concentrations in a 1.0 × 1.0 × 0.5 m enclosure with ventilation openings top and bottom that are 1.0 m across and have a width of either 1 mm (top) or 0.05 mm (bottom). Four gas compositions are tested, as given in Table 3. Dashed lines used flow rates calculated to give the energy flow rate of 0.054 MJ/hr specified in IGE/UP/1 (Scenario II). The solid black line is the result for the methane MPLR flow rate of 0.0014 m^3/hr.

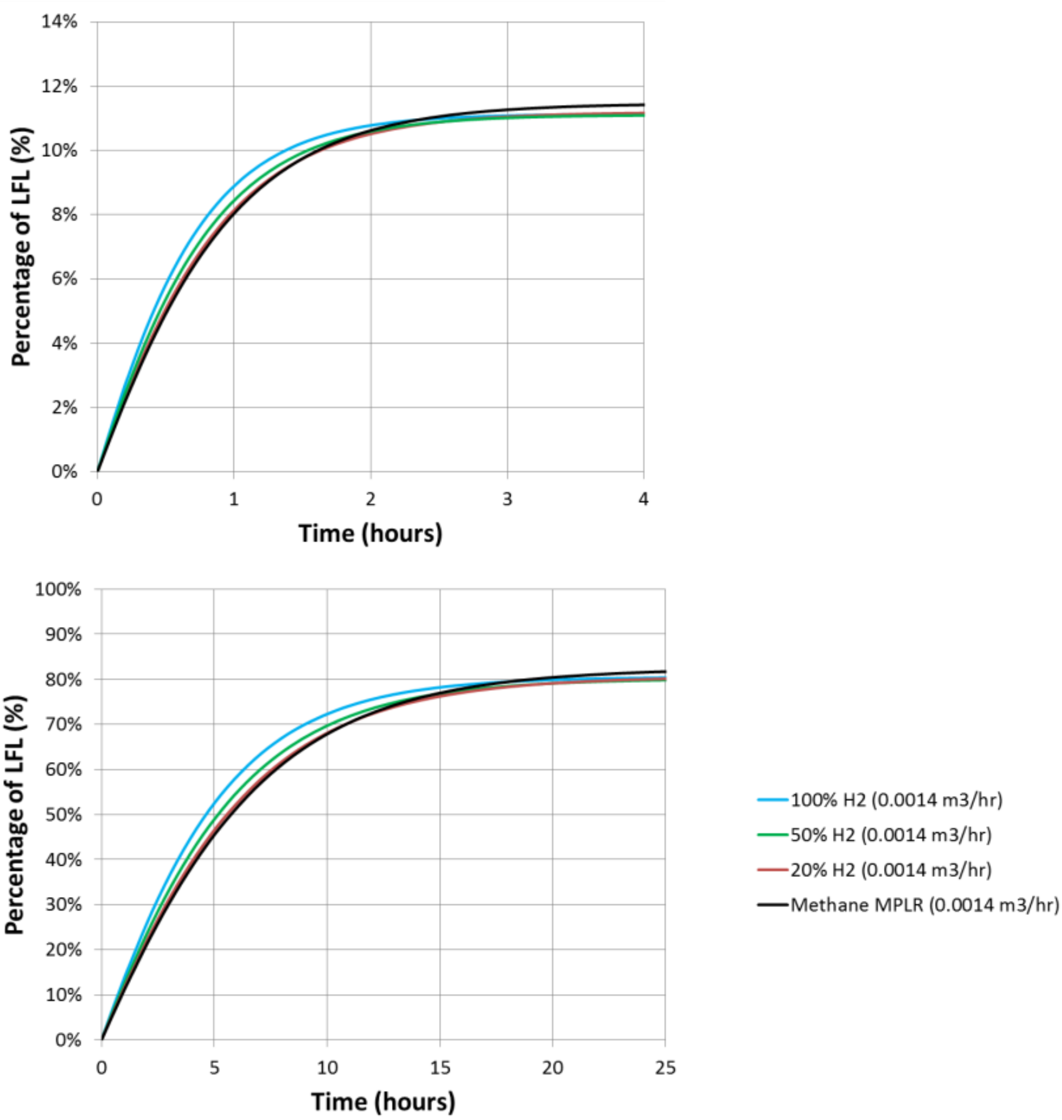

Figure 9 Predicted concentrations in a 1.0 × 1.0 × 0.5 m enclosure with ventilation openings top and bottom that are 1.0 m across and have a width of either 1 mm (top) or 0.05 mm (bottom). Four gas compositions are tested, as given in Table 3. The leak rates for all of the gases is 0.0014 m^3/hr, which is currently the MPLR for natural gas in IGE/UP/1 (Scenario III).

6 CONCLUSIONS

Gas discharge and dispersion models have been analysed to assess the impact of blending hydrogen into natural gas in the UK gas transmission and distribution network. The work on gas discharge rates by Swain and Swain (1992) has been extended to consider compressible subsonic and choked releases. The results showed that these higher pressure releases behave in the same way as incompressible turbulent releases, in terms of the increase in hydrogen volume flow rate relative to methane.

Empirical correlations from Chen and Rodi (1980) have been used to assess the change in the extent of flammable clouds of hydrogen-blends relative to methane. For turbulent vertical jet releases from round holes, the analysis predicted that hydrogen-blends would produce larger flammable clouds than the equivalent methane releases. For pure hydrogen, the distance to LFL was predicted to be 3.5 times the distance for methane. For pure buoyancy-dominated plumes, flammable hydrogen clouds were predicted to extend only 1.5 times the distance of the equivalent methane clouds. These results were confirmed by comparing results to predictions from the Quadvent-2 area-classification software tool.

To demonstrate a practical application of the methods presented in this report, they were used to investigate the IGE/UP/1 procedure on leak tightness testing. Results from the analysis suggested that gas installations that have been leak tested in accordance with IGE/UP/1 under natural gas should have no increased risk of producing flammable clouds if the gas is switched to a blend of 20% hydrogen in natural gas (assuming the hole size, pressure and temperature are unchanged). IGE/UP/1 currently defines a method for calculating the MPLR volumetric flow rate for different gases in terms of energy content. If this method is used to calculate the MPLR for pure hydrogen and hydrogen blends, gas accumulation calculations showed that the resulting higher volumetric flow rates would lead to an increased risk of producing flammable clouds. It was shown that a possible solution to this issue could be to define the MPLR for pure hydrogen and hydrogen blends to be the same as the current MPLR for natural gas in volumetric terms rather than energy, i.e. 0.0014 m^3/hr for new installations or existing installations with Area Type A. The gas accumulation model predicted practically identical gas concentrations in terms of percentage LEL for pure methane, hydrogen blends and pure hydrogen in that case.

Future work should consider extending the preliminary analysis presented here to instead use realistic natural gas compositions instead of pure methane. This may affect some of the results, particularly those for high-pressure releases. Work is continuing at HSE and DNV GL on the H21, H100, HyDeploy and Hy4Heat projects to further investigate gas leakage and dispersion behaviour of pure hydrogen and hydrogen blends. As part of the H21 project, leakage tests are being undertaken at the HSE Science and Research Centre in Buxton on assets that have been recovered from the UK gas network. DNV GL is also conducting experiments at Spadeadam on gas releases both above and below ground. HSE is also conducting wind-tunnel experiments to validate gas accumulation models for hydrogen blends as part of the HyDeploy-2 project, and DNV GL is conducting tests on confined gas releases within buildings for the Hy4Heat project. All of this work will contribute to the evidence base to support the safe repurposing of the gas network for hydrogen, which ultimately will help us to meet climate-change targets.

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APPENDIX A

The book on turbulent buoyant jets by Chen and Rodi (1980) provides an excellent review of experimental data, together with useful correlations for concentration in jets and plumes (which were used earlier in this report). However, some of the equations presented in their book appear at first sight to be ambiguous or contradictory. Molkov (2015) has also noted that several papers in the literature have incorrectly written the equations for concentration in jets. The aim of this Appendix is to provide additional supporting material to help interpret the equations presented by Chen and Rodi (1980) and other papers in the literature, and to help resolve several issues.

There are two equations presented by Chen and Rodi (1980) for the decay of concentration with distance in momentum-dominated jets (on Pages 28 and 37 of their book):

$$C^* = 5\left(\frac{\rho_0}{\rho_a}\right)^{-\frac{1}{2}}\left(\frac{x}{D}\right)^{-1} \qquad \text{(A.1)}$$

$$\frac{\Delta c_{cl}}{\Delta c_0} = 5.4\left(\frac{\rho_0}{\rho_a}\right)^{\frac{1}{2}}\left(\frac{x}{D}\right)^{-1} \qquad \text{(A.2)}$$

There is an important difference between these two equations in relation to the density ratio (ρ_0/ρ_a), where in the first equation this ratio is raised to the power (-1/2) and in the second equation it is raised to the power (1/2). At first sight, this might appear to be a typographical error, but this is not the case, as will be explained below.

The parameter C^* is defined by Chen and Rodi (1980) in their nomenclature as a dimensionless density:

$$C^* = \frac{\rho_a - \rho_{cl}}{\rho_a - \rho_0} \qquad \text{(A.3)}$$

where ρ_a, ρ_0 and ρ_{cl} are, respectively, the ambient density, the source fluid density, and the centreline density (i.e. the density of the mixture of source fluid and ambient fluid on the centreline of the jet at distance x).

The density of a mixture of two fluids is the volume-fraction weighted sum of the component fluid densities, i.e.:

$$\rho_{cl} = f\rho_0 + (1-f)\rho_a \qquad \text{(A.4)}$$

where f is the volume fraction of the source fluid. Substituting Equation A.4 into A.3 gives:

$$C^* = \frac{\rho_a - [f\rho_0 + (1-f)\rho_a]}{\rho_a - \rho_0} \qquad \text{(A.5)}$$

which can be simplified to:

$$C^* = f \qquad \text{(A.6)}$$

In other words, C^* is the concentration of the source fluid, expressed as a <u>volume</u> fraction.

Returning to Equation A.2, it is unclear in this expression whether the terms Δc_{cl} and Δc_0 are volume fractions or mass fractions. Chen and Rodi (1980) simply referred to c as being a concentration. Equation A.2 is presented in their book beside a graph of the concentration decay in jets, which includes various experimental datasets for carbon dioxide, helium, air and smoke (see Figure A.1). To determine whether the terms Δc_{cl} and Δc_0 are mass fractions or volume fractions, the source of the experimental data plotted in their graph has been investigated.

The experimental data presented in Figure A.1 for helium and carbon dioxide (cited by Chen and Rodi as reference [44]) is a conference paper by Keagy and Weller (1949). This 70 year old conference paper is difficult to source. The RAND website[16] notes that the conference paper was superseded by a report published by the same authors (Keagy *et al*., 1949), and RAND provides a digital print of this report on their website.

The Keagy *et al*. (1949) RAND report presents two graphs for concentrations in jets of helium and carbon dioxide, consisting of model predictions and measurements (reproduced here in Figure A.2). Keagy *et al*. (1949) stated that the concentration, C, in these figures was a volume fraction. The square and round symbols in Figure A.2 are marked as concentration and velocity, respectively. However, it appears that there is a mistake and they should be the opposite way around (i.e. ■ should be velocity, and ● should be concentration). This hypothesis is supported by the fact that symbols match the model predictions when they are the opposite way around, and the report makes no mention of this otherwise strange coincidence. Furthermore, the conference paper by Keagy and Weller (1949) (which can still be obtained from ASME for a fee) presents the symbols the opposite (i.e. correct) way around (see Figure A.3). There are also data points that appear in Keagy and Weller's graphs (Figure A.3) which are absent in the Keagy *et al*. report (Figure A.2).

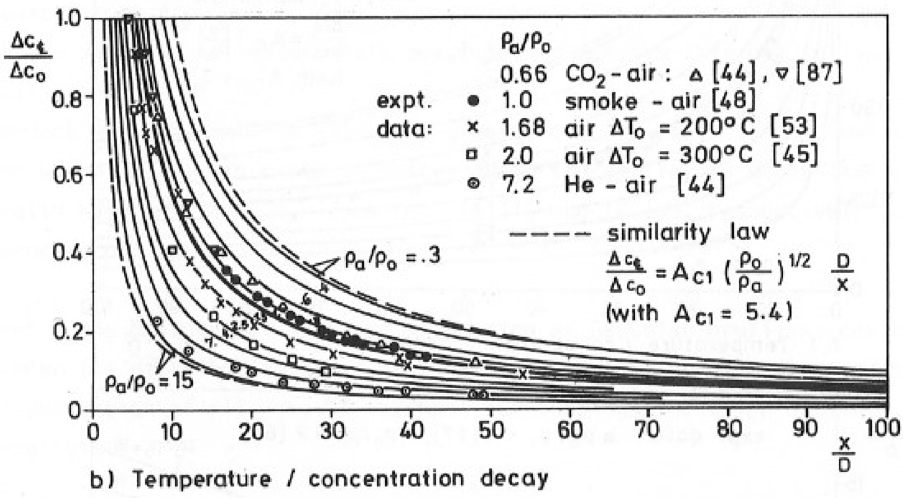

Figure A.1 Concentration (mass fraction) in turbulent round jets. Reprinted with permission from Chen and Rodi (1980).

[16] https://www.rand.org/pubs/papers/P55.html, accessed 15 October 2019.

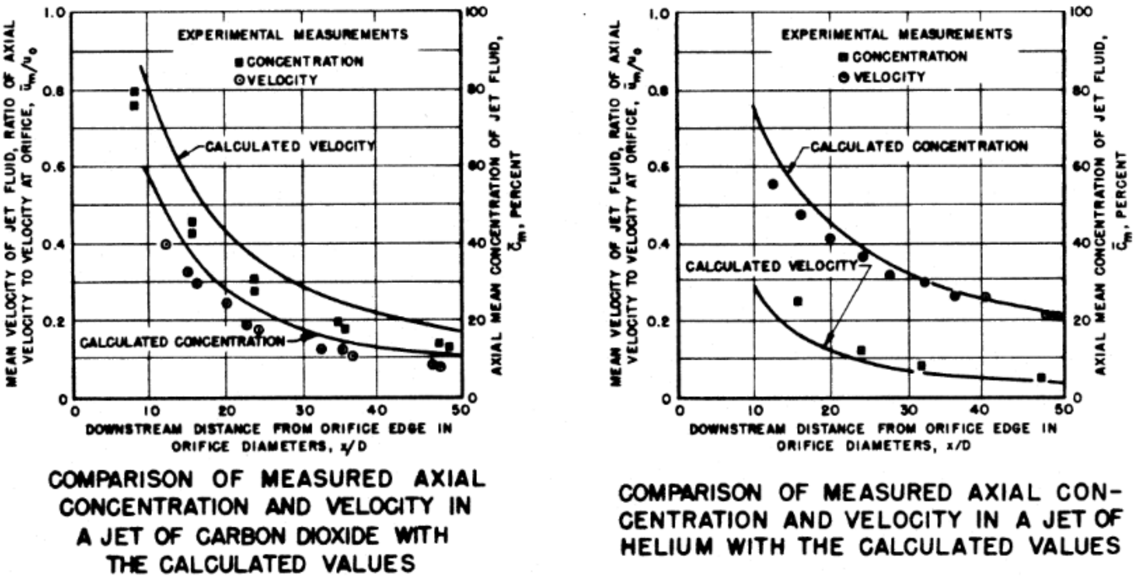

Figure A.2 Concentration (volume fraction) in jets of carbon dioxide and helium, reproduced with permission from Keagy *et al.* (1949) © RAND Corporation

Concentration data from Keagy and Weller (1949) have been digitised and converted from volume fractions to mass fractions, using the following formulae:

$$y = \frac{f M_0}{f M_0 + (1 - f) M_a} \tag{A.7}$$

where M_0 is the molecular weight of the source gas (either carbon dioxide $M_0 = 44$ g/mol, or helium $M_0 = 4$ g/mol) and M_a is the molecular weight of the ambient fluid (air, $M_a = 29$ g/mol). The graph of mass fraction (y) versus distance (x/D) has then been overlaid on the original graph from Chen and Rodi (1980) (see Figure A.4) to demonstrate that the two datasets are in agreement. The conclusion from the analysis of these graphs is that the concentrations presented in Chen and Rodi's data (Figure A.1) and in their Equation A.2 for the ratio ($\Delta c_{cl}/\Delta c_0$) are <u>mass</u> fractions.

Molkov (2015) reached this same conclusion and he also noted that other authors, including Birch *et al.* (1984, 1987), had incorrectly written the concentration in jets as being in terms of the volume fraction, f:

$$f = 5.4 \left(\frac{\rho_a}{\rho_0}\right)^{\frac{1}{2}} \frac{D}{x} \tag{A.8}$$

This equation, which Molkov (2015) stated was incorrect, is the same as Equation A.1 presented by Chen and Rodi (1980), except for the minor difference in the constant (a value of 5.4 versus 5).

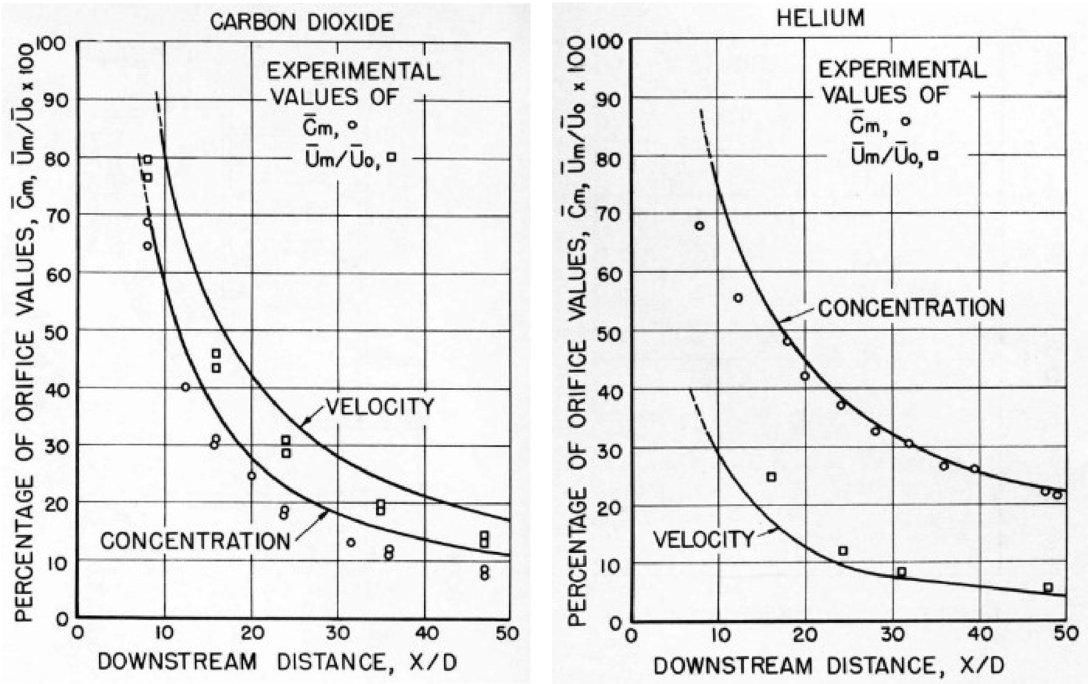

Figure A.3 Concentration (volume fraction) in jets of carbon dioxide and helium, reproduced with permission from Keagy and Weller (1949) © ASME

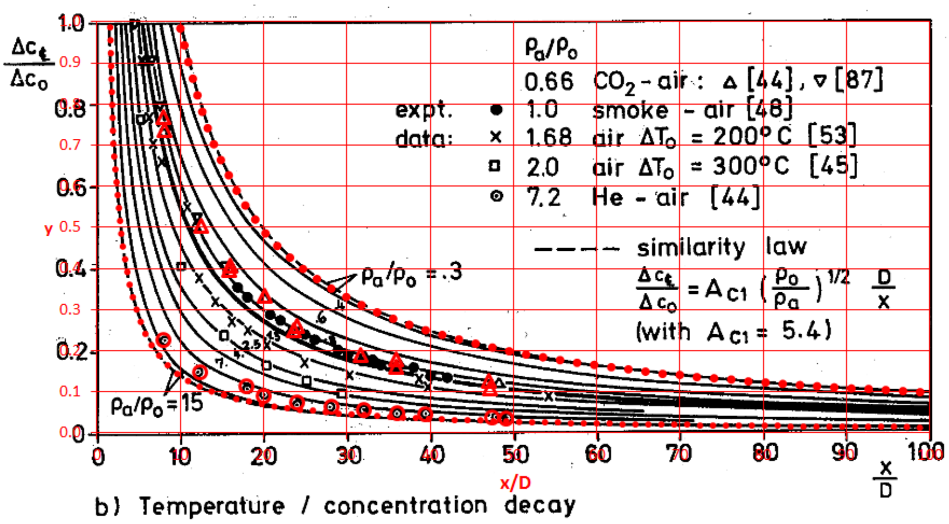

Figure A.4 Concentration (mass fraction) graph from Chen and Rodi (1980) (in black) overlaid with data from Keagy and Weller (1949) (in red)

Chen and Rodi (1980) demonstrated good agreement between measurement data and their correlation for mass fraction (Equation A.2 in Figure A.1) but did not show results in terms of the volume fraction. It is useful to make this comparison to show whether their formula for volume fraction (Equation A.1) or that of Birch *et al*. (Equation A.8) shows similarly good agreement.

To convert a mass fraction (y) into a volume fraction (f), the following equation can be used:

$$y = f\frac{\rho_0}{\rho_{cl}} \tag{A.9}$$

where ρ_{cl} is the density of the mixture of source and ambient fluids on the jet centreline at the given concentration (see Equation A.4). Substituting this into Equation A.8 gives:

$$y = f\frac{\rho_0}{\rho_{cl}} = 5.4\left(\frac{\rho_0}{\rho_a}\right)^{\frac{1}{2}}\left(\frac{x}{D}\right)^{-1} \tag{A.10}$$

which can be rearranged to give:

$$f_{CR2} = 5.4\left(\frac{\rho_{cl}}{\rho_0}\right)\left(\frac{\rho_0}{\rho_a}\right)^{\frac{1}{2}}\left(\frac{x}{D}\right)^{-1} \tag{A.11}$$

Here the subscript $CR2$ has been added to denote that this equation originates from second of Chen and Rodi correlations (Equation A.2), for the mass fraction.

If the centreline density is assumed to be approximately equal to the ambient density ($\rho_{cl} \approx \rho_a$), the above equation can be written:

$$f_B \approx 5.4\left(\frac{\rho_0}{\rho_a}\right)^{-\frac{1}{2}}\left(\frac{x}{D}\right)^{-1} \tag{A.12}$$

which matches the Birch *et al*. equation (Equation A.8) – hence the subscript B in this expression for Birch. This approximation that the centreline density is equal to the ambient density is valid in situations where the source fluid density is similar to the ambient density, or where the distances of interest are sufficiently far downstream that the concentration of the source fluid is low. To explore whether this approximation is valid for the cases of interest here, Figure A.5 shows the experimental data from Keagy and Weller (1949) in terms of the volume fraction with three sets of model predictions, using Equations A.1, A.11 and A.12.

Looking at the helium data in Figure A.5, Molkov (2015) is correct in the sense that Equation A.11 matches the experimental data, whilst the other two approximations (Equations A.1 and A.12) over-predict the concentration significantly near the source (a factor of 1.6 over-prediction at $x/D = 20$). The approximation used by Birch *et al*. (1984, 1987) (Equation A.12) is not valid in this near field region for helium.

The difference between the three models is much less significant for carbon dioxide, where all three Equations give similar results. This change in behaviour depending on the gas (helium versus carbon dioxide) is related to the difference in the density between source fluid and the ambient. For helium, the source and ambient densities are different by a factor of 7, whereas for carbon dioxide it is just a factor of 1.5.

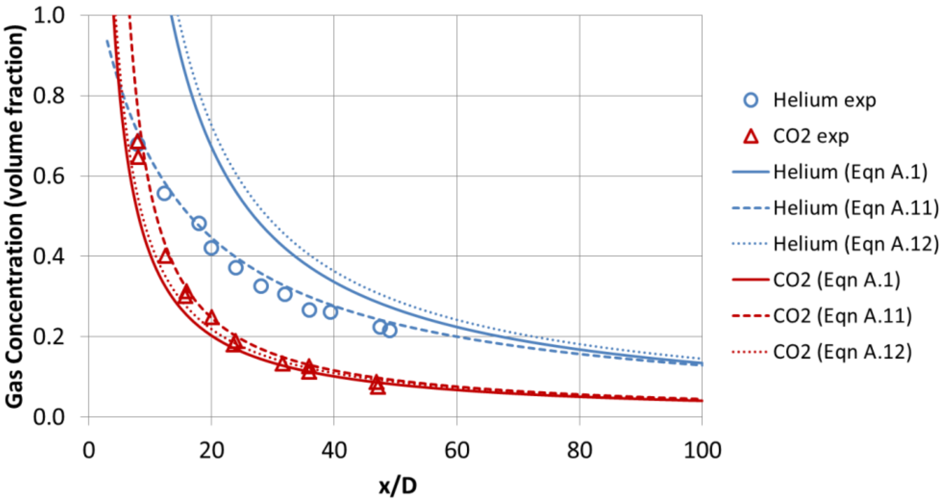

Figure A.5 Concentration (volume fraction) in jets of helium and carbon dioxide. Symbols show data from Keagy and Weller (1949). Lines show three different model predictions, using Equations A.1, A.11 and A.12.

Birch *et al*. (1984) examined jets of natural gas, which has a difference in density relative to air of a factor of approximately 1.8. In their later work, Birch *et al*. (1987) studied jets of air. Therefore, in their work, the approximation that $\rho_{mix} \approx \rho_a$ was valid.

When we consider hydrogen, the difference in density between hydrogen and air is a factor of 14. Therefore, based on the results shown in Figure A.5, the approximation $\rho_{mix} \approx \rho_a$ should not be used in the near-field. The difference in behaviour with methane and hydrogen is shown in Figure A.6.

The difference between the correlations (Equations A.1, A.11 and A.12) diminishes with distance downstream, as the jet density approaches the ambient density. If the primary interest is in assessing the distance to the LFL concentration it would appear from Figure A.6 that the correlations should give similar results, i.e. a small error. The error resulting from the approximation $\rho_{mix} \approx \rho_a$ can be assessed by equating Equations A.11 and A.12 (i.e. setting $f_{CR2} = f_B$). After some algebra, this gives:

$$\frac{x_{CR2}}{x_B} = 1 - f_{CR2}\left(1 - \frac{\rho_0}{\rho_a}\right) \qquad (\text{A.13})$$

The above equation expresses the difference between the Chen and Rodi (1980) and Birch *et al*. correlations in terms of the ratio of the distances predicted by the two models (x_{CR2}/x_B) as a function of the concentration, f_{CR2}, and the density ratio, ρ_0/ρ_a. The two correlations tend to give the same predictions (a ratio of x_{CR2}/x_B approaching a value of 1) as the source fluid density tends to the ambient density ($\rho_0/\rho_a \rightarrow 1$) or as the concentration tends to zero ($f_{CR2} \rightarrow 0$).

The LFL for hydrogen is 4% v/v (i.e. $f_{CR2} = 0.04$) and the density ratio is $\rho_0/\rho_a = 2/29$. The above equation gives the result that the distance to LFL using the Chen and Rodi (1980) correlation (Equation A.11) is 1.04 times the distance to the LFL from the Birch *et al*. (1984, 1987) correlation (Equation A.12). For the distance to 50% LFL, the factor is 1.02. Further results are plotted in Figure A.7 for hydrogen and methane. Overall, for the distances commonly of interest (i.e. distance to LFL and 50% LFL), the error resulting from assuming $\rho_{mix} \approx \rho_a$ is relatively modest (an error of less than 5% in the predicted distance to LFL).

In summary, Chen and Rodi (1980) presented two equations for concentrations in jets: the first one in terms of the volume fraction (Equation A.1) and the second in terms of the mass fraction (Equation A.2). The second equation was derived from analysis of experimental data for jets of fluids with different densities and the equation matches the data well. The first equation appears to have been derived from the second equation with the simplifying assumption that the source fluid density is similar to the ambient density. A similar assumption appears to have been used by Birch *et al*. (1984, 1987). This assumption can lead to relatively large errors in predicted concentrations near to the source when the source and ambient fluid densities are very different. For example, for helium in air the error in predicted concentration is around 30% v/v helium concentration at a distance of 20 jet source diameters (a prediction of 70% v/v versus a measured concentration of 40% v/v). For fluids with similar densities to the ambient (e.g. methane or carbon dioxide in air) these errors are minor or negligible. Also, at distances far downstream (irrespective of the fluid density) the errors diminish. For hydrogen in air at a distance downstream where the concentration falls to LFL, the error in the predicted distance to the LFL is just 4% (i.e. the difference between a distance of $x = 1.00$ and 1.04). For the 50% LFL, the error in the predicted distance is 2%.

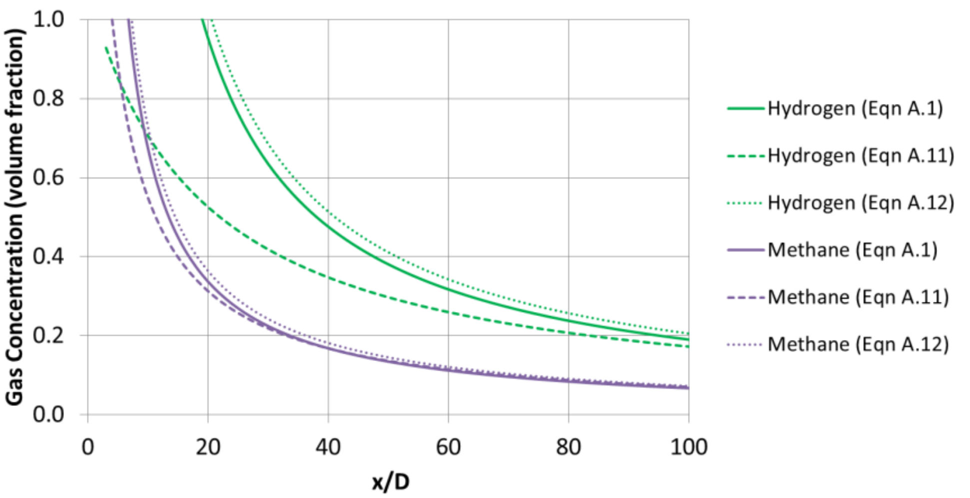

Figure A.6 Concentration (volume fraction) in jets of hydrogen and methane. Lines show three different model predictions, using Equations A.1, A.11 and A.12.

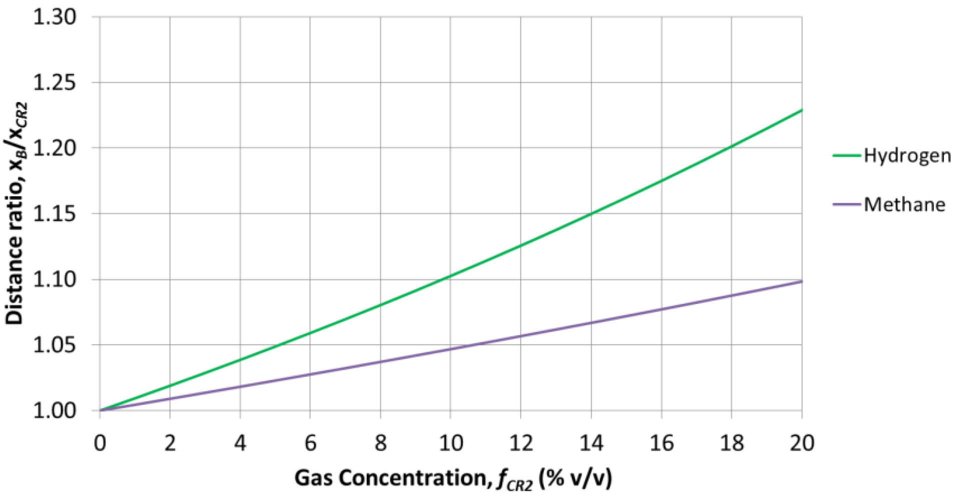

Figure A.7 Distance ratio x_B/x_{CR2} as a function of gas concentration for hydrogen and methane. This expresses the error in the predicted distance to a given concentration due to the assumption used by Birch *et al*. (1984, 1987) that the jet density is equal to the ambient density. For a gas concentration of 10% v/v, there is a 10% error in the distance for hydrogen and a 5% error in the distance for methane.

Hydrogen has the potential to be used as part of decarbonising the future energy system. Hydrogen can be used as a fuel 'vector' to store and transport low-carbon energy. Several UK projects are investigating the potential use of the existing natural gas transmission and distribution network to transport either hydrogen, or blends of hydrogen and natural gas, from production or storage sites to domestic or commercial appliances such as boilers, cookers, fires and ranges. Mathematical modelling is important to inform risk assessments to ensure that levels of safety for the public are maintained.

This report describes preliminary mathematical modelling of potential leaks from gas network assets such as valves and pipes when hydrogen, or hydrogen blends, are transported or used. The research considers the potential impact of leak rates and the dispersion behaviour of the gas. It uses published information from laboratory-scale experiments. The report presents a preliminary modelling case study to show how this potential impact might affect a commonly-used UK gas industry leak tightness testing procedure.

This research will be of interest to risk assessment specialists in the gas industry.

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APPENDIX 10: REVIEW OF EMERGING TECHNIQUES FOR HYDROGEN PRODUCTION FROM METHANE AND REFINERY FUEL GAS WITH CARBON CAPTURE

Review of emerging techniques for hydrogen production from methane and refinery fuel gas with carbon capture

Date: January 2023

Contents

1. Introduction

During 2019 and 2020, the UK environmental regulators[1] ('the regulators') received pre-application enquiries from several operators who were proposing to build new or modified plants for the large scale production of hydrogen (H_2), using methane (CH_4) from natural gas and/or refinery fuel gas (RFG) as a feedstock, with associated carbon dioxide capture and storage (CCS).

It is anticipated that these H_2/CCS plants will be an important component of the UK Government climate change policy to achieve Net Zero carbon emissions by 2050. The UK Department for Business, Energy, and Industrial Strategy (BEIS) is promoting the development of hydrogen as a fuel and carbon capture usage and storage (CCUS) at several locations in the UK.

- UK hydrogen strategy - GOV.UK (www.gov.uk)
- UK carbon capture, usage and storage - GOV.UK (www.gov.uk)

[Note: The need to review techniques and develop further guidance notes covering hydrogen production by other routes / technologies as they arise, is recognised by the regulators.]

Large scale industrial production of hydrogen is a long-established process in the UK. The best available techniques (BAT) reference document (BRef) for the manufacture of hydrogen in oil refineries was published in 2015[2] and the BRef for the manufacture of hydrogen in ammonia plants was published in 2007[3]. Neither of these BRef documents considers hydrogen production when combined with CCS.

Where there is no relevant BRef, or where related BAT conclusions do not address all the potential environmental effects, the regulator must set permit conditions, including emission limit values, on the basis of best available techniques that it has determined for the activities or processes. This shall be after prior consultations with the operator following the

[1] The Environmental Regulators for H_2/CCS are the Environment Agency (EA) in England, the Scottish Environment Protection Agency (SEPA) in Scotland, Natural Resources Wales (NRW) in Wales and the Northern Ireland Environment Agency (NIEA), an executive agency of the Department of Environment, Agriculture and Rural Affairs, in Northern Ireland.

[2] Best Available Techniques (BAT) Reference Document for the Refining of Mineral Oil and Gas, IED 2010/75/EU, 2015.

[3] Best Available Techniques for the Manufacture of Large Volume Inorganic Chemicals – Ammonia, Acids and Fertilisers, 2007.

requirements in Article 14(6) of the Industrial Emissions Directive 2010/75/EU (IED) and give special consideration to the criteria for determining BAT in Annex III of the IED.

These criteria include, amongst others, review of comparable processes, types and quantity of emissions, energy efficiency, efficient use of raw materials and prevention or reduction of overall impact of emissions on the environment.

The UK regulators commissioned this emerging techniques review and produced a summary of emerging techniques guidance because there is no existing guidance that is specific to the production of hydrogen when combined with CCS. This is new technology and there is limited evidence or data available for performance of comparable sites.

This review details the key environmental issues to address and information about best practice available on a selection of hydrogen production with carbon dioxide capture options. After consultation with industry, the regulators consider these are the most likely to be proposed by applicants in the short to medium term (1 to 5 years).

The guidance is based on current information which is publicly available and also on information which has been provided at our request by industry.

The guidance is not a regulatory requirement. It does not have the same regulatory status as BAT reference documents or related BAT conclusions. However operators would need to explain and justify where alternatives to methods and performance described in the guidance are proposed. Operators are encouraged to make contact with the appropriate regulator at the earliest possible opportunity.

Where emission limit values (ELVs) are required to meet IED Chapter III Special Provisions for Combustion Plant or the Medium Combustion Plant Directive 2015/2193/EU (MCPD), these will be set in permits. Where an emission level associated with the best available technique (BAT-AEL) applies from a relevant BRef, these may also be set though the latter may be granted derogation for up to 9 months if the technology is considered emerging, to allow testing and use (IED Article 15(5)). Permit conditions will be set to protect the environment by ensuring environmental quality standards are met (Article 18).

The UK regulators envisage that the emerging techniques review and emerging techniques guidance will be used by:

- operators when designing their plants and preparing their application for an environmental permit
- their own staff when determining environmental permits

- any other organisation or members of the public who want to understand how the environmental regulations and standards are being applied

The scope of this review and guidance is limited to preventing or reducing emissions into the environment and does not cover other aspects such as safety.

The guidance document provides a framework for applications and permits and is based on information available at this time. Further information about the performance of the processes will become available as they are further developed and commence operation. The UK regulators will keep BAT and emerging techniques under review as required by Article 19 of IED.

The UK regulators would like to thank everyone who has provided data and helped in the production of this review.

2. Abbreviations / definitions

Abbreviation	Description
ASU	Air Separation Unit
ATR	Autothermal Reformer
BAT	Best Available Techniques
BEIS	Business, Energy, and Industrial Strategy
BRef	BAT Reference Document
CCR	Carbon Capture Readiness
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilisation and Storage
DAA	Directly Associated Activity
EAL	Environmental Assessment Level
EIGA	European Industrial Gases Association
ELV	Emissions Limit Value
GHR	Gas Heated Reformer
GTL	Gas To Liquids (typically conversion of natural gas to liquid fuels)
HT	High Temperature
IEA	International Energy Agency
IED	Industrial Emissions Directive
LT	Low Temperature
MT	Medium Temperature
OTNOC	Other Than Normal Operating Conditions
POX	Partial Oxidation
PSA	Pressure Swing Adsorption
RFG	Refinery Fuel Gas
SEPA	Scottish Environment Protection Agency
SCR	Selective Catalytic Reduction
Shift	CO shift, also termed water gas shift, the reaction of carbon monoxide with water to produce hydrogen and CO_2
SNCR	Selective Non-Catalytic Reduction
SMR	Steam Methane Reformer
Syngas	Synthesis gas – a gas mixture containing carbon monoxide and hydrogen, with other components such as CO_2 and water also potentially present
TSA	Temperature Swing Adsorption
UK	United Kingdom
VSA	Vacuum Swing Adsorption

3. Study approach and activities

3.1. Overview of study approach

3.1.1. Definition of scope boundaries

This guidance considers production of hydrogen from methane[4] with CO_2 capture. The various process units in the scope boundary and interfaces are shown in Figure 1.

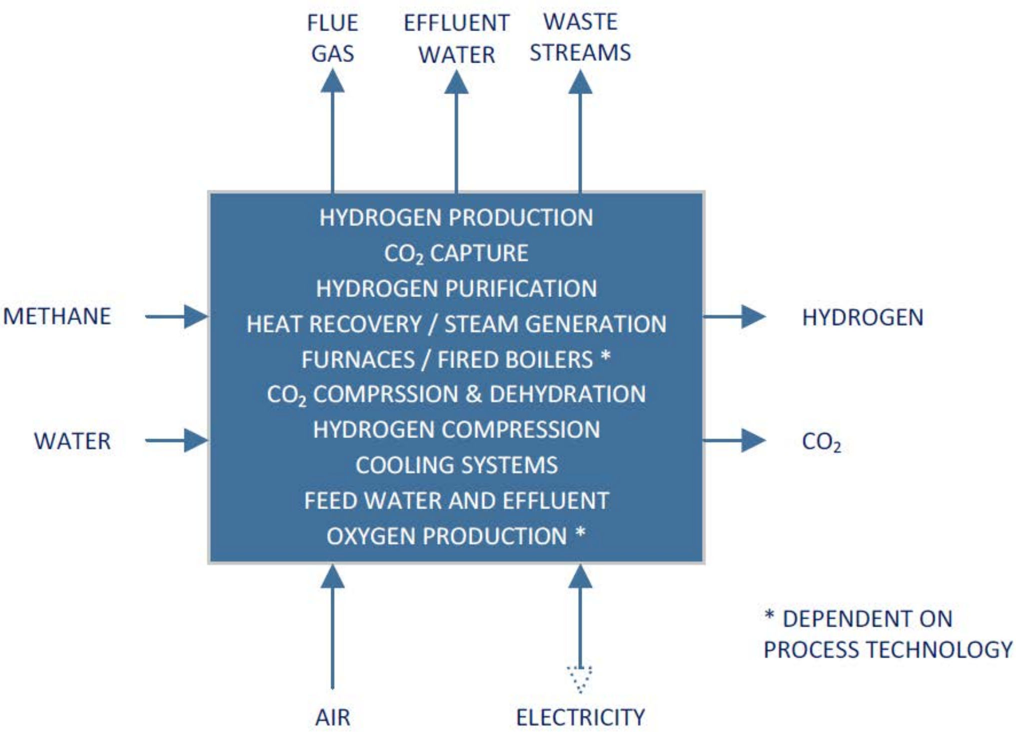
This guidance specifically excludes the following activities:

- upstream gas production, processing, compression
- hydrogen transportation
- CO_2 transportation and storage
- CO_2 emissions other than those directly related to the hydrogen production activity, such as in production of gas feedstock, in generation of imported electrical power, or in transportation and end use of hydrogen product

The above activities may form part of an integrated stationary technical unit for the purposes of an environmental permit, as directly associated activities (DAAs) or as regulated activities in their own right. In this case, it is expected that the best available techniques (BAT) against all these regulated activities and/or DAAs are identified in accordance with relevant BAT reference documents or guidance documents as appropriate.

[4] Methane sources include natural gas from production / processing facilities, LNG import facilities, gas transmission or distribution networks; or refinery fuel gas derived from a range of off-gas streams within a refinery complex. Alternative sources of methane include biomethane or biosynthetic natural gas (BioSNG).

Figure 1 – Project scope boundaries



3.1.2. Scope boundaries – plant scale

This description of available techniques is intended to cover hydrogen production applications at a scale of hundreds of tonnes of hydrogen per day, designed for capture of the resultant CO_2 for storage.

Small scale production will be considered in future guidance, if descriptions and guidance in this document are deemed not to be applicable.

Several ongoing UK projects have proposed production capacity of 200 to 300 MW or greater of hydrogen energy[5] (based on lower heating value), equivalent to 144 to 216 t/day of hydrogen.

This does not represent a limit on individual hydrogen production train size, with 700 to 1500 MW output potentially feasible with some multiple equipment items in parallel, depending on production technology.

[5] Hydrogen production of 300 MW lower heating value is equivalent to 100 kNm^3/h or 9,000 kg/h, with approximately 0.7 million tonnes per annum CO_2 capture.

3.1.3. Scope boundaries – feed and products

Feed and products boundaries, basis and exclusions are summarised in Table 1.

Table 1: Study boundaries – feed and products

	Description	Exclusions	Notes / Basis
Methane	Supply of methane rich feed gas, either natural gas or refinery fuel gas. Assumed to meet gas network quality, for example, Gas Safety (Management) Regulations, or local refinery fuel gas quality.	Excluding upstream gas production, processing, and transport.	Suitable pressure to feed hydrogen production process, for example from high pressure gas network. Feed gas compression may be required depending on the available source pressure. Additional process steps may be required, dependent on composition, for either natural gas or RFG feed gases. RFG streams in particular could contain various sulphur species including H_2S and organic sulphur compounds and impurities such as mercury, chlorides, and olefins.
Hydrogen	Hydrogen product quality suitable for combustion as an industrial or domestic fuel [Ref. 11].	Excluding production of hydrogen to 'fuel cell quality'.	For example, typical proposed specification [Ref. 11]: $H2 \geq 98$ vol% * $CO \leq 20$ ppmv $CO2 + HCs \leq 2$ vol% * This is typical, and lower H_2 purity specifications may be practical, to make allowance for inerts such as nitrogen and argon from the feed gas and oxygen supplies passing with the hydrogen product,

			depending on the technology used for hydrogen purification. Pressure as delivered from production and purification process. Compression may be required for transportation / delivery to users.
Carbon dioxide	CO_2 meeting specification for downstream transportation (pipeline or shipping) and storage. Including CO_2 compression, dehydration and any purification requirements (for example, oxygen removal) depending on capture location, technology and impurities.	Excluding transportation and storage infrastructure, pipeline CO_2 compression or pumping, CO_2 liquefaction, and so on.	To pipeline quality specifications, considering oxygen, CO, H_2 and water content CO_2 quality requirements may vary depending on the transportation and storage infrastructure [Ref. 13]. There may be differences in CO_2 delivery pressure from the capture processes employed, impacting CO_2 compression requirements. CO_2 compression delivery pressure will depend on whether the CO_2 is to be transported in the gaseous or dense phase.

3.1.4. Scope boundaries – utilities

Utilities requirements for the hydrogen production and CO_2 capture processes are identified in Table 2.

Table 2: Study boundaries – utilities

	Description	Exclusions	Notes / Basis
Electrical power	Connection to network for import / export of electricity.		Dedicated power generation / heat to be included in boundary of assessment.

	Description	Exclusions	Notes / Basis
			A cogeneration plant may be considered where both steam production and power generation can be achieved, integrating steam and power systems in the hydrogen production and CO_2 capture processes, and where excess is produced to export to external users.
Water supply	Feed water for boiler / process, cooling water make up.	Excluding treatment, for example to towns water equivalent standard.	Production of demineralised boiler feed water and removal of impurities.
Air	Air for combustion or oxygen production (where required by process).		Including air compression and associated cooling for ASU.
Cooling	Process cooling requirements.		Cooling against air, closed or evaporative cooling water systems.
Fuel	Fuel for fired equipment – furnaces / heaters / boilers.		Produced within process (off gas or product hydrogen) or taken from feed gas.
Steam	At pressure levels to suit process requirements and heat integration.		Generated within plant boundary in heat exchange with process streams or from fired boiler / flue gas heat recovery systems. This is an area of potential integration with other industrial facilities for import or export of steam.

	Description	Exclusions	Notes / Basis
Flare	For combustion of non-routine controlled or emergency releases.		An elevated or ground flare system will be required to handle any controlled releases from planned and unplanned operations, such as start-up operation, planned or unplanned shutdown operation. Plant design should ensure that operations including planned start-up and shutdown minimise flaring, to limit emissions to air. Methods for monitoring / calculating flared gas volumes should be identified to confirm compliance with permit conditions.

3.1.5. Scope boundaries – emissions, effluents and wastes

Boundaries in terms of emissions, effluents and wastes are identified in Table 3.

Table 3: Study boundaries – emissions, effluents, and wastes

	Description	Exclusions	Notes / Basis
Emissions	Atmospheric emissions from combustion or other processes		Emissions considering any combustion activities, accounting for use of hydrogen rich fuels and impacts of post-combustion CO_2 capture where appropriate. Any continuous or intermittent venting or flaring – for example on start up. Loss of containment emissions.
Effluents	Liquid effluents		Effluent from cooling systems and steam systems.

	Description	Exclusions	Notes / Basis
			Water condensed in process, following water recovery. Aqueous effluents generated from emission abatement processes and solvent recovery / management activities.
Wastes	Any solid or liquid waste streams from operation	Excluding waste water, included under effluents above.	Degraded solvents, spent catalysts and adsorbents, considering recovery and recycling. Solids from process.

3.1.6. Key considerations for emerging techniques

Assessment of BAT criteria and emerging techniques should consider the following aspects where appropriate in technology selection, overall plant design, and development of operational philosophies and procedures.

Technology selection should include the following key environmental considerations:

- emissions to air
- emissions to water
- waste minimisation and waste treatment (liquid and solid waste streams)
- abatement techniques to reduce emissions (for example, airborne species resultant from solvent degradation)
- CO_2 capture rate
- energy efficiency
- hydrogen losses
- treatment of captured CO_2 for transport (for example, quality requirements)

Plant design and operations should address the considerations above and also those following, with reference to existing relevant standards where appropriate:

- monitoring standards for stack emissions (including averaging periods for dispersion modelling)
- monitoring standards for discharges to water (including averaging periods and arrangements for flow monitoring)
- air dispersion modelling standards
- ambient / deposition monitoring standards
- noise (for example, in compression of captured CO_2, fans, burners)
- maximising energy efficiency (including heat integration and optimisation, considering for example opportunities for heat recovery from compression systems)
- water use efficiency (for process use and cooling systems)
- optimisation of use of raw materials
- start-up and shutdown of operations (including ramp rates)
- other than normal operating conditions
- accident management, leak monitoring and containment arrangements, including loss of containment emissions
- monitoring for emissions of CO_2

3.1.7. Existing BAT reference documentation

Existing BAT reference (BRef) documents, relevant to the technologies covered in this report, are identified in Table 4. The Industrial Emission Directive 2010/75/EU Article 14 (6) and Annex III must be consulted to ensure compliance with the stated requirements.

Table 4: List of existing BAT reference documentation

Existing BAT reference	Subject (as relevant to this review)
Reference document on best available techniques for manufacture of large volume inorganic chemicals – Ammonia, Acids and Fertilisers, 2007	Steam reforming, autothermal reforming, hydrogen purification
Best available techniques (BAT) reference document for the refining of mineral oil and gas, IED 2010/75/EU, 2015, EUR 27140 EN BAT conclusions for the refining of mineral oil and gas (2014/738/EU)	Hydrogen production (partial oxidation, steam reforming, gas heated reforming and hydrogen purification) Energy efficiency techniques (heat integration / recovery and steam management)

Existing BAT reference	Subject (as relevant to this review)
Best available techniques (BAT) reference document for common waste water and waste gas treatment / management systems in the chemical sector, IED 2010/75/EU, 2016, EUR 28112 EN BAT conclusions for common waste water and waste gas treatment / management systems in the chemical sector (2016/902/EU)	Waste water collection and treatment process integrated measures
Best available techniques (BAT) reference document for large combustion plants, IED 2010/75/EU, 2017, EUR 28836 EN BAT conclusions for large combustion plants (2017/1442/EU)[6, 7]	Best available techniques for large combustion plants, including measures to reduce emissions of pollutants from combustion processes and BAT-associated emission levels and energy efficiency levels for large combustion plants.
Reference document on the application of best available techniques to industrial cooling systems, 2001	Cooling water systems
Reference document on best available techniques for energy efficiency, 2009	Energy efficiency and integration management
Reference document on the general principles of monitoring, (2003)	Monitoring of emissions to air and water

[6] The Industrial Emission Directive 2010/75/EU Chapter III and Annex V set the minimum requirements for certain pollutant emissions from LCPs.

[7] Directive (EU) 2015/2193 on the limitation of emissions of certain pollutants into the air from MCPs known as the Medium Combustion Plant Directive (MCPD) regulates pollutant emissions from the combustion of fuels in plants with a rated thermal input equal to or greater than 1 MWth and less than 50 MWth.

3.1.8. Other relevant guidance documentation

Guidance documents, potentially relevant to the technologies covered under this report, are included in Table 5.

Table 5: List of guidance documentation – UK environmental regulators

Existing guidance and documentation	Subject (as relevant to this review)
Carbon capture readiness (CCR) A guidance note for section 36 Electricity Act 1989 consent applications, URM 09D/810 November 2009 and amendments.	Process CO_2 capture Post-combustion CO_2 capture
UK TWG 18 submission for combustion sector BRef note revision, carbon capture technology and carbon capture ready criteria, 31/5/2012	Process CO_2 capture Post-combustion CO_2 capture
Review of amine emissions from carbon capture systems, SEPA, 2015	Post-combustion CO_2 capture amine scrubbing systems
Water demand for carbon capture and storage (CCS), Environment Agency November 2012	Process CO_2 capture Post-combustion CO_2 capture
BAT review for new-build and retrofit post-combustion carbon dioxide capture using amine-based technologies for power and CHP plants fuelled by gas and biomass as an emerging technology under the IED for the UK. Post-combustion carbon dioxide capture: best available techniques (BAT) **[Ref. 6, 21]**	Post-combustion CO_2 capture

Existing guidance and documentation	Subject (as relevant to this review)
BAT for new build oxyfuel carbon capture coal-fired plants, V1.9 – May 2015 [Ref. 12]	ASUs
Reference document on the general principles of monitoring, (2003)	Monitoring of emissions to air and water

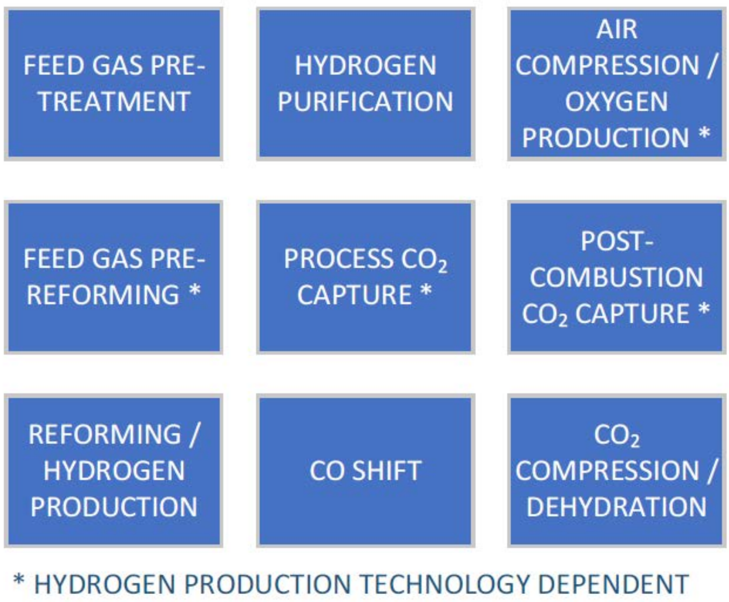
List of guidance documentation – industry

- EIGA, IGC Document 155/21 [Ref. 17]. Best available techniques for hydrogen production by steam methane reforming
- EIGA, IGC Document 88/14 [Ref. 18]. Good environmental management practices for the industrial gas industry
- EIGA, Document 122/18 [Ref. 16]. Environmental impacts of hydrogen plants

3.2. Long list of technologies

The main process steps for hydrogen production from methane with CO_2 capture are shown in Figure 2.

Figure 2 - Main process steps for hydrogen production from methane with CO_2 capture



Available technologies, including established technologies and emerging technologies, are first identified through literature review of technical reports available in the public domain. This includes publications from international organisations, UK organisations, UK academies, professional institutions, and European industry trade associations.

The readiness of the technology for commercial deployment is categorised as follow:

- ‘Mature’ is defined as a technology proven at large scale in manufacturing for the stated industries. Scale up of some elements may still be required.
- ‘Novel at Scale’ is defined as a technology proven at a smaller scale or in other industries – for example, for chemical production.
- ‘Low’ is defined as a technology being studied at Research and Development level and not yet proven at a pilot scale for manufacturing in the stated industries.

3.2.1. Feed gas pre-treatment

Feed gas pre-treatment consists of the removal of contaminants to prevent any catalyst poisoning in the downstream processes - mainly sulphur species and mercury species. Refinery fuel gas can also contain chlorides and heavy metals requiring removal.

Feed gas pre-treatment requirements are dependent on the hydrogen production technology, with some steps being optional. For example, with non-catalytic partial oxidation (POX) technology, depending on feed gas impurity levels, treatment may be needed only to protect the CO shift catalyst downstream of the POX reactor.

Available pre-treatment technologies for sulphur removal are mature and include:

- catalytic reaction to hydrogenate any organic sulphur or organic chlorides to H_2S and HCl respectively
- absorption in a metal oxide bed to form metal sulphide or metal chloride

Where the sulphur content is higher, for example in refinery fuel gas streams, other sulphur removal technologies may be more practical and economical.

Available pre-treatment technologies for mercury removal are also well-established and include, for example, absorption on a metal sulphide bed.

Feed gas pre-treatment is further described in section 4.1.

3.2.2. Feed gas pre-reforming

Feed gas pre-reforming converts the feed gas heavier hydrocarbons into methane. Conversion of the heavier hydrocarbons reduces potential to form carbon in the reformer, and also forms some hydrogen and CO_2.

Feed gas pre-reforming technology is mature and consists of a catalytic reaction using nickel-based catalyst. Feed gas pre-reforming is further described in section 4.2.

For hydrogen production using the non-catalytic POX technology, feed gas pre-reforming is not necessary.

3.2.3. Oxygen production

Oxygen is required for hydrogen production using autothermal reforming (ATR)[8] and partial oxidation (POX) technologies. Technologies for oxygen production include cryogenic and non-cryogenic air separation.

Table 6: Technology long list – oxygen production

Oxygen production technology	Readiness level	Most quoted technologies
Cryogenic air separation	Mature	Cryogenic package including TSA and fractionation
Non-cryogenic air separation	Mature	PSA, VSA, Membrane
Non-cryogenic air separation	Low	Ceramic membranes

Cryogenic air separation

Cryogenic air separation is a mature technology that can produce a high volume of oxygen at high purity (>99.5% O_2). The air separation unit (ASU) will include air compression to multiple pressure levels; air drying and purification using temperature swing adsorption; highly integrated multi-stream heat exchange and cryogenic fractionation in a cold box module; expansion of gases in cryogenic turbo expanders; and cryogenic pumping of oxygen [Ref. 19].

Using cryogenic air separation, liquid oxygen can be produced and stored as a back-up supply.

Very large scale high purity / high pressure oxygen production is conventional for example in gas to liquids production. The Pearl GTL plant at Ras Laffan, Qatar, which uses gas POX

[8] ATR can also be air-blown, producing a nitrogen / hydrogen syngas which could be used as a zero carbon fuel for example for existing gas turbines that would otherwise require steam as a diluent.

technology for production of hydrogen, includes 8 x 3,600 tonnes per day (tpd) oxygen plants. Capacities of over 5,000 tonnes per day of oxygen are possible.

Non-cryogenic air separation

Non-cryogenic air separation technologies are also mature, but used for lower volume oxygen production and/or lower purity (for example, between 85% and 95%), not meeting with the needs for large scale hydrogen production. The most common non-cryogenic air separation technologies are PSA, VSA and membrane technologies [Ref. 19]. Air separation by pressure swing adsorption (PSA), vacuum swing adsorption (VSA), or membrane separation is not currently appropriate at the required large scale and high oxygen purity.

Emerging technologies such as ceramic membranes for air separation are a potential future technology, not currently commercially available.

Other sources of oxygen

Oxygen as by-product of green hydrogen production (electrolysis of water) could potentially supplement supply and provide incremental improvement in overall efficiency where facilities can be co-located, although such schemes are immature, and it is not expected that this will be a route to large scale oxygen supply in the short term. The oxygen would be produced at low pressure and would require compression to deliver at the pressure required for hydrogen production.

3.2.4. Hydrogen production technologies

Technologies for hydrogen production from methane are listed in Table 7, including associated level of readiness for deployment for hydrogen production with CO_2 capture.

Table 7: Technology long list – hydrogen production

Hydrogen production technology	Readiness level	Industries used
Steam methane reforming (SMR) [Ref. 2] (+ Pre-reforming)	Mature	Methanol, Refining, Petrochemical
Autothermal reforming (ATR) [Ref. 2]	Mature	Ammonia Methanol, Gas To Liquids (GTL)
Combined SMR and ATR [Ref. 4]	Mature	Ammonia Methanol
Combined gas heated reforming (GHR) and SMR [Ref. 22]	Novel at Scale (Combination not demonstrated at large scale)	Ammonia Methanol
Partial oxidation [Ref. 2]	Mature	Ammonia, Methanol, Gas To Liquids (GTL)
Combined GHR and oxygen-blown ATR, parallel configuration [Ref. 4]	Mature	Hydrogen
Combined GHR and oxygen-blown ATR, Series [Ref. 4]	Mature	Ammonia Hydrogen Methanol

Hydrogen production technology	Readiness level	Industries used
Sorption enhanced steam methane reforming (SE-SMR) [Ref. 7][9]	Low	Hydrogen
Pyrolysis [Ref. 2]	Low	Hydrogen
Microwave technologies [Ref. 2]	Low	Hydrogen
Dry reforming	Low	Hydrogen
Plasma reforming	Low	Hydrogen
Solar SMR	Low	Hydrogen
Tri-reforming of methane	Low	Hydrogen

9 Bulk Hydrogen by Sorbent Enhanced Steam Reforming (HyPER), led by Cranfield University, is being supported under Phase 2 of the BEIS UK Hydrogen Supply Competition to demonstrate this novel technology at pilot scale, Hydrogen Supply Competition Phase 2 successful projects - GOV.UK (www.gov.uk)

3.2.5. CO shift technologies

CO shift is a catalytic reaction, which converts CO and water (steam) to hydrogen and CO_2. The CO shift process is further defined in section 4.3.

Technologies for CO shift (water gas shift) are listed below, including associated level of readiness for deployment for large scale hydrogen production with CO_2 capture.

Table 8: Technology long list – CO shift (water gas shift)

CO shift technology	Readiness level	Relevant industries
High temperature (HT) CO shift conversion HT operation at 300 to 450°C ~2.5% mol CO dry basis at reactor outlet	Mature	Ammonia Hydrogen
Medium temperature (MT) CO shift conversion MT operation at 220 to 270°C ~0.5% mol CO dry basis at reactor outlet	Mature	Hydrogen
High temperature / low temperature (HT/LT) CO shift conversion LT operation at 180 to 230°C ~0.2% mol CO dry basis at reactor outlet	Mature	Ammonia Hydrogen
Isothermal CO shift conversion Operation at MT or LT level for high conversion to CO, with heat exchange within the reactor to produce steam. An inlet temperature of 240°C is typical,	Mature	Ammonia Hydrogen

CO shift technology	Readiness level	Relevant industries
peaking at 280 to 300°C, with outlet pressure at an approach to the steam production temperature. ~0.5% mol CO dry basis at reactor outlet		
CO sour shift Used for syngas streams containing H_2S. The sour shift converts CO with water to H_2 and CO_2. The shifted gas contains acid gas (both H_2S and CO_2).	Mature	Ammonia Methanol Hydrogen
Sorption enhanced CO shift	Low	Hydrogen

3.2.6. CO_2 capture technologies

For low carbon hydrogen production from methane, CO_2 can potentially be captured as follows:

- process CO_2 capture – from process streams such as hydrogen product downstream of CO shift, with advantages of high pressure and/or high CO_2 concentration (upwards of 24 vol% depending on the hydrogen production technology)
- post-combustion CO_2 capture – from combustion flue gases such as from reformer furnace, at near atmospheric pressure, with relatively low CO_2 concentration (around 10 to 20 vol%) and in the presence of oxygen, nitrogen, and other combustion products

For process CO_2 capture both physical and chemical absorption are potentially applicable technologies. In post-combustion capture, chemical absorption is the only option due to the low partial pressure of CO_2.

Process CO_2 capture technologies and post-combustion CO_2 capture technologies are listed in Table 9, along with their associated level of readiness for deployment.

Table 9: Technology long list – process CO_2 capture

Process CO_2 capture technology	Readiness level [Ref. 10]	Most quoted technologies [Ref. 10]
Absorption – chemical solvents	Mature	Amine solvents, for example, formulated MDEA solvents, Amine Guard FS (UCARSOL®), aMDEA, ADIP ULTRA Hot potassium carbonate (for example, Benfield®, Catacarb®)

Process CO_2 capture technology	Readiness level [Ref. 10]	Most quoted technologies [Ref. 10]
Absorption – physical solvents	Mature	DEPG[10] (for example, Selexol® Genosorb®) Methanol (for example, Rectisol®) n-methyl-2-pyrrolidone (for example, Purisol®)
Absorption – hybrid solvents	Mature	for example, Sulfinol®[11]
Cryogenic separation	Novel at Scale	Low temperature partial condensation for bulk CO_2 separation, downstream of CO shift or on compressed PSA tail gas
Membrane separation	Low	H2 membrane integrated into ATR for example, MTR Polaris® for example, Carbon Molecular Sieve (CMS) membrane
Chemical looping reforming [Ref. 2]	Low	Metal oxide
Pressure swing adsorption (PSA)	Mature	Adsorber beds with pressure swing regeneration

[10] Dimethyl ethers of polyethylene glycol

[11] Tetrahydrothiophene 1,1-dioxide (Sulfolane), an alkaloamine and water

Process CO_2 capture technology	Readiness level [Ref. 10]	Most quoted technologies [Ref. 10]
Vacuum swing adsorption (VSA)	Novel at Scale (Demonstrated at large scale, but limited references)	Adsorber beds with vacuum swing regeneration

Table 10: Technology long list – post-combustion CO_2 capture

Post-combustion CO_2 capture technology	Readiness level [Ref. 10]	Most quoted technologies [Ref. 10]
Absorption - chemical solvents	Novel at Scale (Demonstrated at large scale but limited references)	Amine solvents for example, MEA based processes such as Fluor Econamine FG Plus^{SM} or proprietary amine processes such as Shell CANSOLV® or MHI KS-1^{TM}, a hindered amine
Absorption - chemical solvents	Low	Ammonia Amino-acid Hot potassium carbonate Proprietary non-amine solvents
Membrane separation	Low	for example, MTR Polaris® Metal oxide
Chemical looping combustion	Low	Adsorber beds with regeneration

Post-combustion CO_2 capture technology	Readiness level [Ref. 10]	Most quoted technologies [Ref. 10]
Solid sorbents	Low	Zeolites, metal-organic frameworks, amine impregnated solids

3.2.7. Hydrogen purification technologies

Hydrogen purification technologies are listed with their associated level of readiness for deployment in Table 11.

Table 11: Technology long list – hydrogen purification

Hydrogen purification technology	Level of readiness	Most quoted technologies
Adsorption - PSA	Mature	Adsorber beds with pressure swing regeneration
Methanation	Mature	Nickel based catalysts

3.2.8. CO_2 dehydration

CO_2 streams are typically produced at low pressure, requiring compression and dehydration prior to delivery to CCS transportation and storage infrastructure. A large proportion of water will be condensed and separated as the CO_2 is cooled after each compression stage.

There are two main techniques for dehydration of CO_2, both mature and widely used:

- temperature swing adsorption, for example, using molecular sieve in a fixed bed, regenerated by passing hot CO_2 gas over the bed to desorb water. Cooling of the regeneration gas allows water to be condensed and separated
- glycol absorption, for example, with counter-current contact of CO_2 and circulating tri-ethylene glycol solvent. Thermal regeneration is used to strip water from the rich glycol solvent

It may also be necessary to remove oxygen from CO_2 from post-combustion capture, which can be achieved by catalytic reaction with hydrogen. As the temperature requirements are modest at around 80°C, the reactor can be located between the CO_2 compressor and aftercooler, prior to dehydration.

3.3. Technology screening

A high level screening of technologies has been conducted against the scope boundaries.

The short list of technologies is based on consideration of:

- technologies that can achieve the production scale that are likely to be proposed in line with UK decarbonisation objectives
- technologies with a suitable level of readiness for deployment:
    - mature technologies applied in equivalent service and at the required scale and design operating envelope (for example, pressure)
    - combinations of technologies proven in operation, but not previously combined in equivalent service or at the required scale

The short list of technologies excludes technologies with low readiness level.

- existing hydrogen production technologies that may be a candidate for retrofit of CO_2 capture
- technologies that are being considered for current UK projects

3.4. Short list of technologies

This short list of technologies that may be employed in hydrogen production with CO_2 capture, represents a current view of available technologies and may require update in the future as novel technologies come forward and are ready for deployment.

Technologies short list

Feed gas sulphur pre-treatment

- hydrogenation and H_2S removal with metal oxide

Feed gas mercury pre-treatment

- mercury removal unit with activated carbon
- mercury removal unit with metal sulphide

Pre-reforming (optional)

- pre-reformer with catalyst bed

Hydrogen production

- steam methane reforming (SMR)
- autothermal reforming (ATR)
- gas heated (convective) reforming (for example, GHR+ATR or GHR+SMR)
- partial oxidation (POX)

Oxygen production

- cryogenic air separation unit (ASU)

CO shift

- high temperature CO shift
- high temperature / low temperature CO shift
- isothermal CO shift
- sour CO shift

Process CO_2 capture

- chemical solvent absorption (for example, amine)
- physical solvent absorption
- hybrid solvent absorption
- low temperature separation
- vacuum swing adsorption (VSA)

CO_2 dehydration

- molecular sieve temperature swing adsorption (TSA)
- tri-ethylene glycol (TEG) Absorption

Post-combustion CO_2 capture

- chemical solvent absorption – amines

Hydrogen purification

- pressure swing adsorption (PSA)
- methanation

4. Technology overview

In this section, a technology overview is provided for the main processes involved in hydrogen production from methane with CO_2 capture under three different hydrogen production schemes:

- hydrogen production from methane using SMR technology with CO_2 capture (Fig.3) In the reforming section, the SMR can be combined with a gas heated reformer (GHR)
- hydrogen production from methane using ATR technology with CO_2 capture (Fig.4) In the reforming section, the ATR can be combined with a gas heated reformer (GHR)
- hydrogen production from methane using POX technology with CO_2 capture (Fig.5)

Each block flow diagram identifies:

- the main process steps for hydrogen production (in purple)
- the main process steps for CO_2 capture (in orange)
- the feed gas and associated products and by-products (in purple)
- the associated utility systems, power, heat recovery and steam generation (in blue)
- the waste recovery and recycling systems (in green)
- the scope of this guidance (within the dotted blue line)

Figure 3 – Block flow diagram of SMR technology with carbon capture

(Typical – Other configurations are possible, for example, with addition of gas heated reformer)

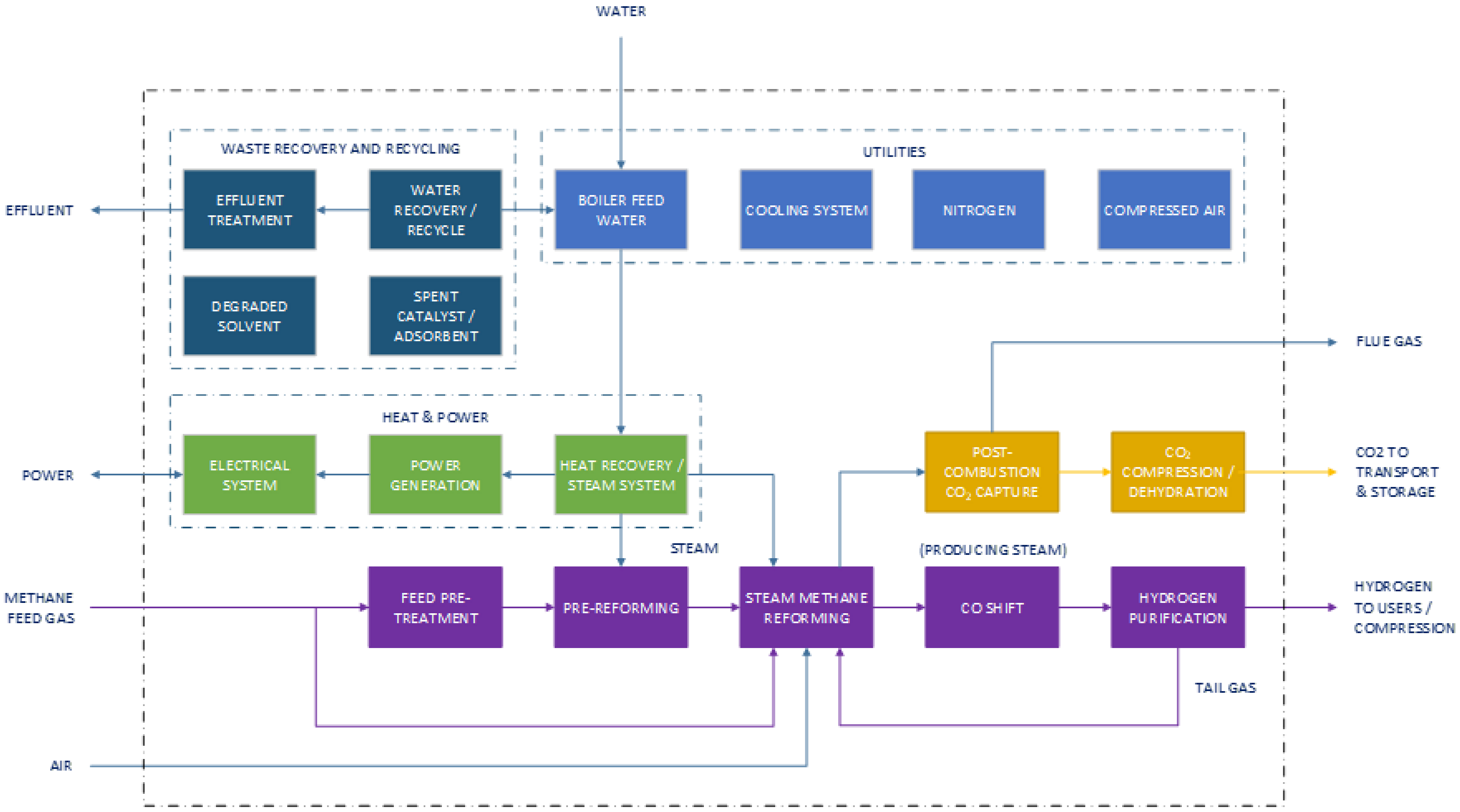


Figure 4 – Block flow diagram of ATR technology with carbon capture

(Typical – other configurations possible, for example, with addition of gas heated reformer)

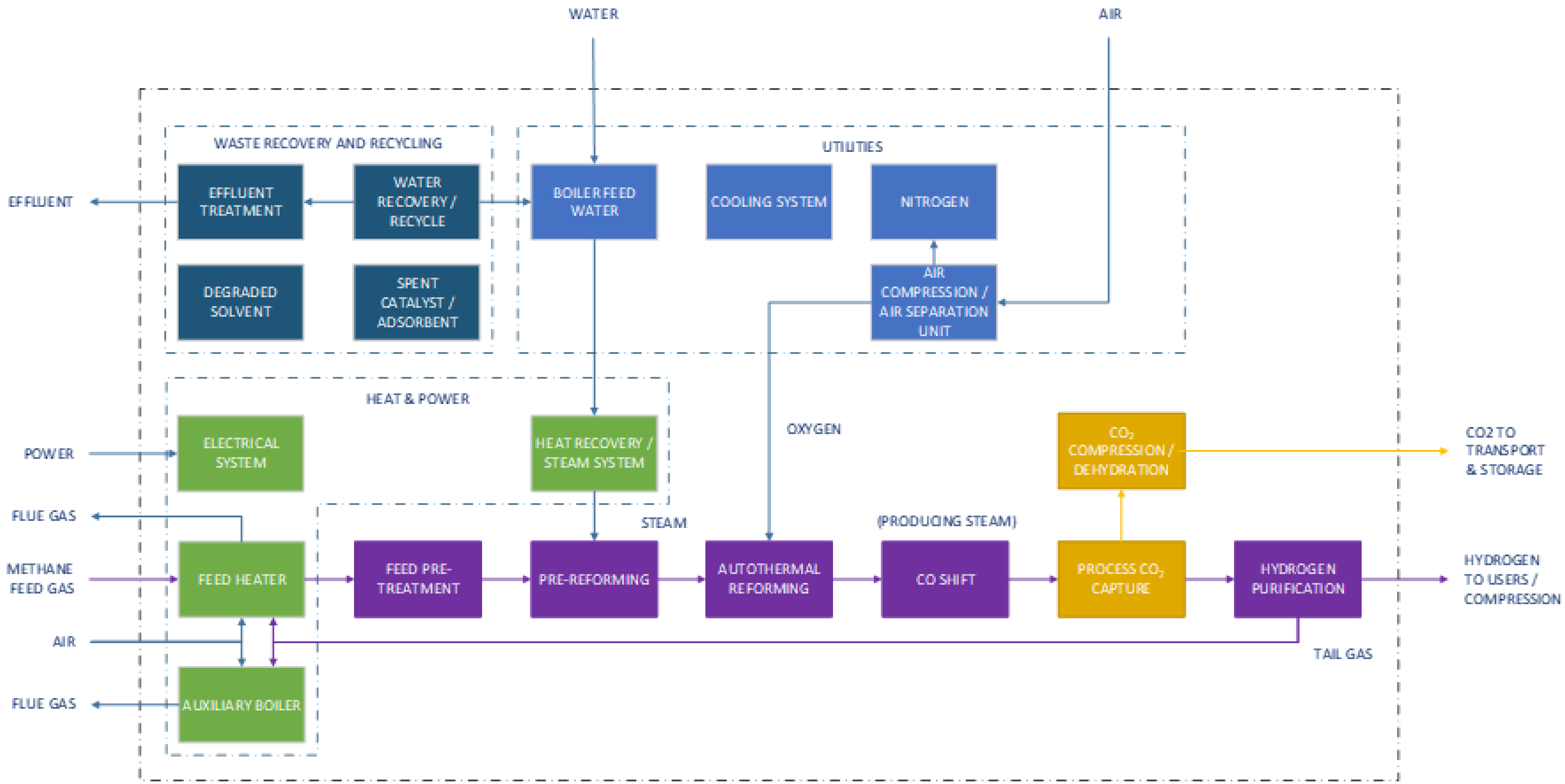
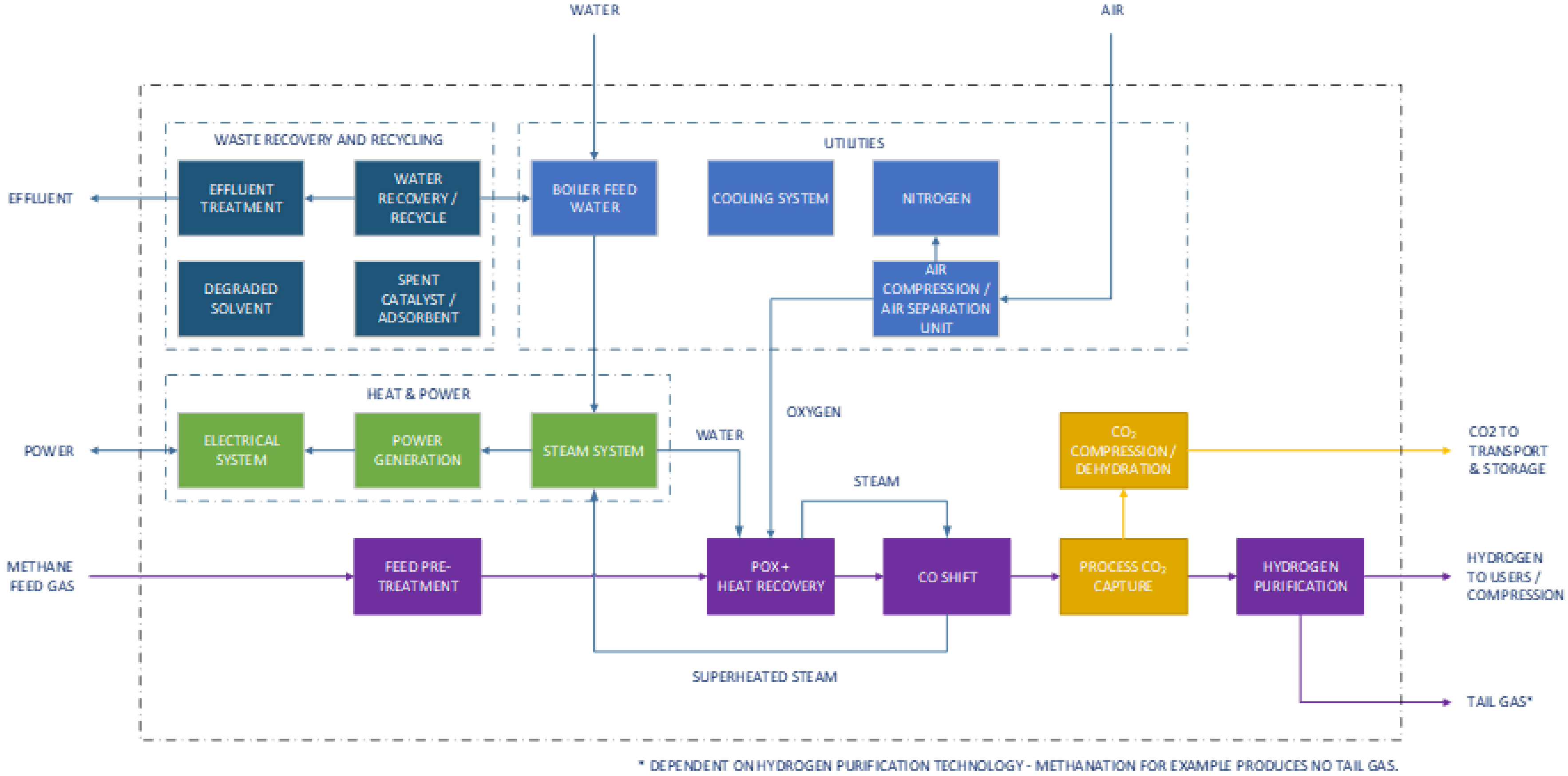


Figure 5 – Block flow diagram of POX technology with carbon capture

(Typical – Other configurations are possible)



4.1. Feed gas pre-treatment

4.1.1. Sulphur removal

The feed gas, natural gas or RFG, may require to be first pre-treated to remove any sulphur species to prevent poisoning and deactivation of the reforming and CO shift catalysts. Sulphur treatment includes hydrogenation using catalyst based technology such as cobalt molybdenum to convert the sulphur species to H_2S, which is then absorbed on a zinc oxide bed. The feed gas is preheated to 200 to 400°C. The chemical reactions occurring in the sulphur removal step are shown in Table 12.

Table 12: Sulphur removal chemical reactions

Chemical reactions	
Hydrogenation	$R\text{-}SH + H_2 \rightleftharpoons H_2S + RH$
Desulphurisation	$H_2S + ZnO \rightleftharpoons ZnS + H_2O$

4.1.2. Mercury removal

The feed gas, natural gas or RFG, may require to be first pre-treated to remove any mercury species to prevent poisoning and deactivation of the downstream reforming catalyst. Mercury removal step includes a mercury removal unit, which would typically consist of fixed bed reactor with an adsorbent. Elemental mercury removal is achieved either by reaction with sulphur-impregnated activated carbon (S) or with a metal sulphide (MeS) and forms a stable solid of mercury ore called cinnabar on the adsorbent. The chemical reactions occurring in the mercury removal step are shown in Table 13.

Table 13: Mercury removal chemical reactions

Chemical reactions	
Elemental sulphur reaction	$Hg^0 + S \rightleftharpoons HgS$
Metal sulphide reaction	$Hg^0 + 2MeS \rightleftharpoons HgS + Me_2S$

4.2. Feed gas pre-reforming

Pre-reforming is an optional step that can be required upstream of a SMR or ATR for processing feed streams containing heavier hydrocarbons such as ethane, propane and butane, and to increase robustness to varying feed gas composition The pre-reforming step converts the feed gas heavier hydrocarbons into methane in a steam reforming step using a nickel based catalyst and operating at lower temperature than that of the main reforming process (450 to 500°C).

By converting the heavier hydrocarbons into methane, the pre-reforming step reduces the required tube area, energy consumption and NO_x emissions in the case of SMR technology due to decreased firing in the main reformer. In the case of ATR technology, it reduces the oxygen and energy consumption.

The chemical reactions occurring in steam methane pre-reforming are shown in Table 14.

Table 14: Pre-reforming chemical reactions

Chemical reactions	
Pre-reforming (1)	$(CH_2)_n + nH_2O(g) \rightleftharpoons nCO + 2nH_2$
Pre-reforming (2)	$(CH_2)_n + 2nH_2O(g) \rightleftharpoons nCO + 3nH_2$
Water gas shift	$CO + H_2O(g) \rightleftharpoons H_2 + CO_2$

4.3. Hydrogen production

4.3.1. Steam methane reforming (SMR) and shift technology

In steam methane reforming, methane reacts with steam and is converted to hydrogen and carbon monoxide using a nickel catalyst. The carbon monoxide produced as part the methane / steam reaction then reacts with steam (through water gas shift reaction) increasing the hydrogen yield and producing CO_2. The chemical reactions occurring in steam methane reforming are shown in Table 15.

Table 15: Steam methane reforming and shift chemical reactions

Chemical reactions		
Steam methane reforming	$CH_4 + H_2O_{(g)} \rightleftharpoons CO + 3\ H_2$	ΔH_{298} = 206 kJ/mol
Water gas shift	$CO + H_2O_{(g)} \rightleftharpoons H_2 + CO_2$	ΔH_{298} = - 41 kJ/mol
Overall reaction *	$CH_4 + 2\ H_2O_{(g)} \rightleftharpoons CO_2 + 4\ H_2$	ΔH_{298} = 165 kJ/mol

* The reformer outlet will contain some unconverted methane and carbon monoxide. The water gas shift is an equilibrium reaction and 15 mol% carbon monoxide and 8% CO_2 would

be typical in the syngas at the outlet of the reforming process on a dry basis. This syngas is passed to water gas shift reactor(s), described in section 4.5, operating at optimal conditions to maximise hydrogen production and conversion of carbon monoxide to CO_2 for capture.

The incoming treated feed gas is preheated against the hot flue gas in the reformer convection section before entering the steam reformer tubes filled with nickel catalyst. As shown in Table 15, the reaction between methane and steam is endothermic hence heat is required to allow the reaction to take place. The steam reformer is heated via an external furnace with multiple burners combusting a fuel source with air.

The fuel source to the furnace burners typically consists of recycled tail gas from the downstream hydrogen purification process, supplemented with feed gas as a makeup fuel. Combustion heat from the reformer flue gas is recovered via a waste heat recovery process to generate steam and to preheat other process streams to maximise energy efficiency. The water gas shift process is exothermic allowing significant production of additional steam.

4.3.2. Autothermal reforming (ATR) and shift technology

In autothermal reforming (ATR), methane is first partially oxidised by oxygen to produce hydrogen and carbon monoxide. Contrary to the steam methane reformer, the autothermal reactor does not require any heat from an external furnace. The partial oxidation reaction is exothermic and provides the required heat to the steam reforming reaction in which methane and steam reacts to produce carbon monoxide and hydrogen in the reformer fixed catalyst bed. The chemical reaction occurring in autothermal reforming are shown in Table 16.

Table 16: Autothermal reforming and shift chemical reactions

Chemical reactions		
Methane partial oxidation	$CH_4 + O_2 \rightleftharpoons CO + 2\ H_2$	ΔH_{298} = -36 kJ/mol
Steam methane reforming	$CH_4 + H_2O_{(g)} \rightleftharpoons CO + 3\ H_2$	ΔH_{298} = 206 kJ/mol
Combined ATR reaction *	$CH_4 + O_2 + H_2O_{(g)} \rightleftharpoons CO + H_2$	ΔH_{298} = 85 kJ/mol
Water gas shift	$CO + H_2O_{(g)} \rightleftharpoons H_2 + CO_2$	ΔH_{298} = - 41 kJ/mol
Overall reaction	$CH_4 + O_2 + H_2O_{(g)} \rightleftharpoons CO_2 + H_2$	ΔH_{298} = 44 kJ/mol

* Based on notional 50:50 split between the methane partial oxidation and steam methane reforming reactions. The reformer outlet will contain some unconverted methane, and the water gas shift reaction within the reformer will lead to a mixture of methane, hydrogen,

carbon monoxide, CO_2 and water in the syngas at the outlet. This syngas is passed to water gas shift reactor(s), described in section 4.5, operating at optimal conditions to maximise hydrogen production and conversion of carbon monoxide to CO_2 for capture.

Oxygen required for the partial oxidation reaction is separated from air, typically cryogenically.

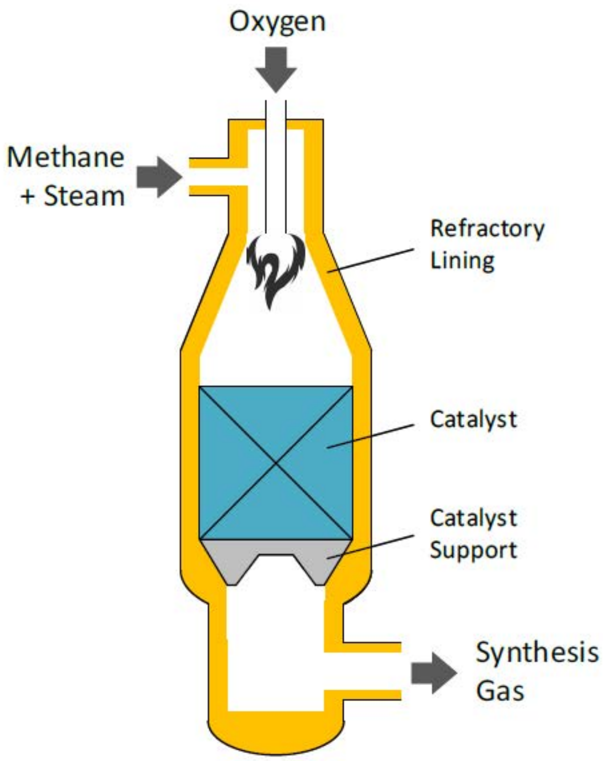
The partial oxidation reaction occurs in the top section of the autothermal reformer. The top section is fitted with a burner where methane and oxygen are mixed in a diffusion flame.

The steam methane reforming reaction occurs in the catalytic bed area, which is located in the bottom section of the reformer. The arrangement of a typical autothermal reformer is shown in Figure 6.

The risk of soot formation exists due to the partial oxidation (reducing atmosphere) and may depend on the following parameters: feed composition, temperature, pressure, burner design, and flow conditions in the combustion zone [Ref. 3]. The catalyst bed immediately downstream may be selected such that any identified soot precursors are destroyed going through the catalytic bed to avoid soot deposition on the catalyst surface, which would reduce heat transfer.

The main differences compared with the steam reforming (SMR) process are the addition of an ASU and feed pre-heater furnace, the absence of an external reformer furnace and associated convective section. There are benefits such as the ability to capture CO_2 from the process without post-combustion capture, and also more rapid production ramping for flexible operation.

Figure 6 – Typical autothermal reformer



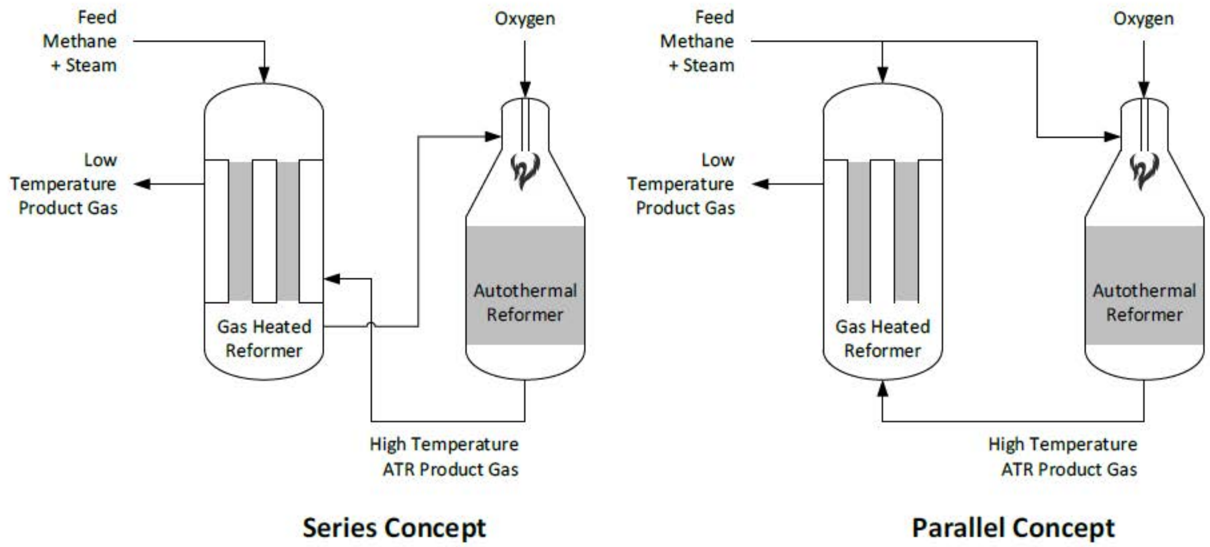
4.3.3. Convective reforming technology

Gas heated reforming (GHR) is an alternative approach to conventional steam reforming. A gas heated reformer consists of a vertical vessel containing tubes filled with catalyst and has a more compact footprint than a steam methane reformer due to the heat transfer being convective rather than radiative.

A gas heated reformer can be used in combination with an autothermal reformer or a steam methane reformer to increase conversion, although it is most commonly seen in combination with an autothermal reformer. A gas heated reformer does not require any external furnace, as the hot main reformer exit gas provides the heat required for the additional endothermic reforming reaction to take place within the gas heated reformer.

GHR and ATR can be used in a series concept or parallel concept, as shown in Figure 7. Similar schemes combining GHR with SMR are possible.

Figure 7 – Convective reforming concepts



In the series concept, the methane and steam feed streams are fed to the GHR where part of the methane is reformed. Partially converted syngas stream from the GHR is then transferred to the ATR for further syngas conversion. The hot syngas produced in the ATR is fed back to the GHR to provide the heat required for the endothermic steam methane reforming reaction to take place via counter current heat exchange. The cooled syngas leaves the GHR and passes to the downstream water-gas shift unit.

In the parallel concept, the methane and steam feed streams are fed to both the GHR and the ATR. The hot gas from the ATR is mixed with the cooler gas leaving the GHR tubes. This mixed gas flows up the shell side of the GHR is cooler and the gas temperature exiting the tube side of the GHR is cooler than in the series scheme.

On a like for like basis, the series concept will minimise methane slip and maximise overall CO_2 capture rates. Additional steam feed would be required to the GHR to compensate for the lower reforming temperature (compared to the ATR outlet temperature) and reduce methane slip from the GHR.

4.3.4. Partial oxidation (POX) technology

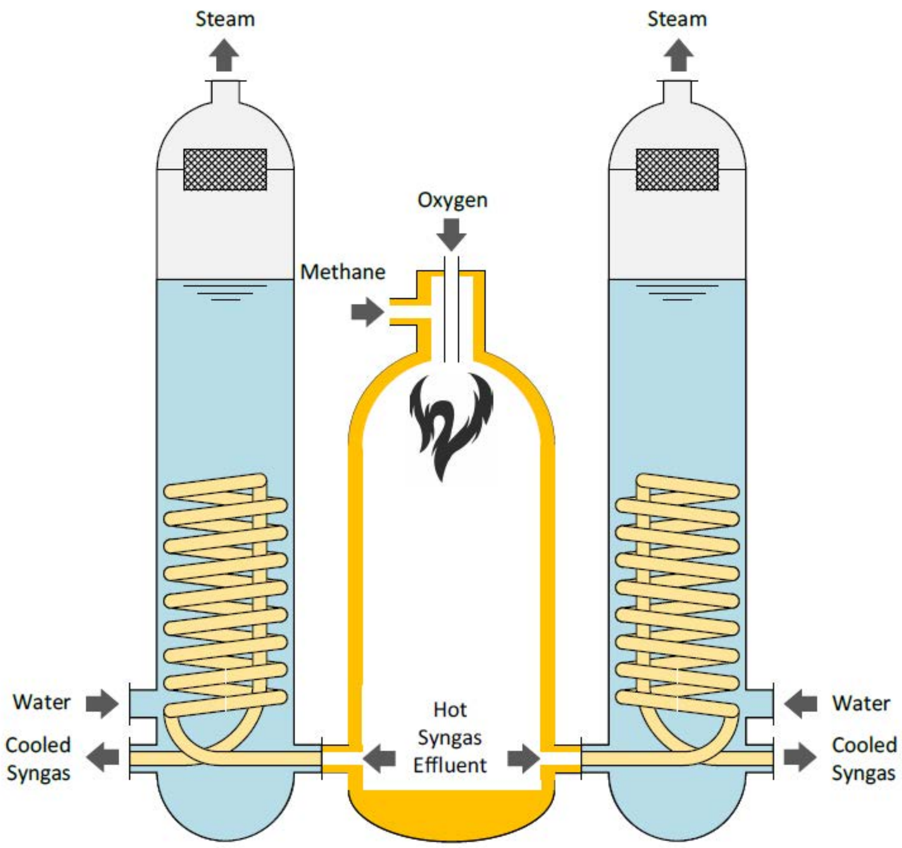
In partial oxidation, methane is first partially oxidised by oxygen to produce hydrogen and carbon monoxide. The partial oxidation reaction is exothermic. The heat produced through the reaction would normally be recovered through the downstream heat recovery process to generate steam from boiler feed water and to preheat other processes to maximise energy efficiency. The chemical reaction occurring in catalytic partial oxidation are shown in Table 17.

Table 17: Partial oxidation and shift technology chemical reactions

Chemical reactions		
Methane partial oxidation	$CH_4 + O_2 \rightleftharpoons CO + 2\ H_2$	ΔH_{298} = -36 kJ/mol
Water gas shift	$CO + H_2O_{(g)} \rightleftharpoons CO_2 + H_2$	ΔH_{298} = -41 kJ/mol
Overall reaction	$CH_4 + O_2 + H_2O_{(g)} \rightleftharpoons CO_2 + 3\ H_2$	ΔH_{298} = -77 kJ/mol

Oxygen required for the partial oxidation reaction is generated through an ASU. Figure 8 shows a typical arrangement in the Shell Blue Hydrogen Process. Feed gas and oxygen is fed at the top of the non-catalytic gas POX reactor, with the syngas from the bottom of the reactor fed to two syngas effluent coolers where reaction heat is recovered to produce high pressure steam.

Figure 8 – Partial oxidation reactor with dual syngas effluent coolers (shell blue hydrogen process)



There are two types of partial oxidation: thermal partial oxidation and catalytic partial oxidation. A key difference between the two types is in the operating temperature and permissible level of sulphur compounds in the feedstock. Thermal partial oxidation occurs at higher operating temperature and can accept higher sulphur feedstocks than the catalytic partial oxidation.

Sulphur can therefore be removed either upstream or downstream of the reactor. Sulphur removal technology and H_2S disposal needs to be considered based on the selected location of the sulphur removal, and the catalyst technology and disposal vs. the alternative of hydrogenation to H_2S, H_2S removal and sulphur recovery.

There is a risk of soot formation, due to partial oxidation (reducing atmosphere) which may depend on the following parameters: feed composition, temperature, pressure, burner design, and flow conditions in the combustion zone [Ref. 3]. In the case of catalytic partial oxidation, the catalyst bed may be selected such that any identified soot precursors are destroyed going through the catalytic bed to avoid soot deposition on the catalyst surface, which would reduce heat transfer. For non-catalytic POX, the amount of soot formation is controlled, and a small amount of soot is typically removed using water wash to protect the downstream equipment.

Syngas from the methane partial oxidation is passed to water gas shift reactor(s), described in section 4.5, operating at optimal conditions to maximise hydrogen production and conversion of carbon monoxide to CO_2 for capture.

4.4. Air separation unit

Oxygen is required for hydrogen production using ATR and POX technologies.

Cryogenic air separation is a mature technology that can produce high volume of oxygen at high purity (>99.5% O_2). The air separation unit (ASU) would include air compression to multiple pressure levels; air drying and purification using temperature swing adsorption; highly integrated multi-stream heat exchange and cryogenic fractionation in a cold box module; expansion of gases in cryogenic turbo expanders; and cryogenic pumping of oxygen [Ref. 19]. The main energy use is in compression of the inlet air.

Using cryogenic air separation, liquid oxygen (and potentially liquid nitrogen) can be produced and stored as a back-up supply.

4.5. CO shift

The syngas stream is fed to the water gas shift reactor(s) to further convert the carbon monoxide into hydrogen and CO_2 through its reaction with excess steam. Considerations to include both high and low temperature or isothermal water gas shift reactors should be taken if higher conversion of carbon monoxide to CO_2 is required.

High levels of shift conversion are usually optimal, particularly where CO_2 is captured from the process and maximising conversion of carbon monoxide to CO_2 leads to higher overall carbon capture. A single shift stage is therefore not usually considered – two shift stages (or isothermal shift) is normal, and three stages may be justified in some cases.

Heat from the exothermic shift reaction can be advantageously recovered into the process or to produce steam. Additional cooling in exchange with ambient air or cooling water is required to cool the shifted syngas further and to remove any free water before the hydrogen purification step.

4.6. CO_2 capture

4.6.1. CO_2 capture locations

CO_2 capture can be achieved at various locations in the hydrogen production process.

With hydrogen production using standard SMR technology, CO_2 capture can be achieved at three different locations:

- process CO_2 capture upstream of the hydrogen purification step

  Approximately 60% of the total CO_2 from the process is present in the shifted syngas at this point (the balance of the CO_2 being in the reformer flue gas from combustion of methane and carbon monoxide in the fuel gas). As near full CO_2 removal can be achieved from the stream, the overall CO_2 capture rate is approximately 60% [Ref. 10].

  This location minimises CO_2 capture cost, but limits CO_2 capture rate. For retrofit of CO_2 capture on existing SMR plants, this may be a viable option.

- CO_2 capture from the tail gas produced in the hydrogen purification step

  Again, up to approximately 60% of the total CO_2, assuming no process CO_2 capture upstream of hydrogen purification.

  CO_2 capture from the hydrogen purification tail gas is a demonstrated alternative to capture upstream of hydrogen purification. Advantages are that the stream is concentrated in CO_2, which suits some capture technologies, and that loss of operation due to trip of the CO_2 capture unit does not impact hydrogen production, as CO_2 is separated from hydrogen in the hydrogen purification (PSA) system and captured downstream,.

  Disadvantages are an increase in sizing of the hydrogen purification system and recovery from a low pressure tail gas stream.

- post-combustion CO_2 capture from the reformer flue gas outlet

  On top of the approximately 60% of the CO_2 produced in the process, this location gives the opportunity to capture and the remaining 40% of the CO_2 resulting from combustion of carbon monoxide and hydrocarbons in the fuel gas.

The advantages of combining process CO_2 capture and post combustion capture are limited, particularly as high CO_2 capture rates of > 95% should be achievable post-combustion. A single capture step would therefore be simplest, with CO_2 removed from the process in the hydrogen purification step (PSA unit), and routed with the tail gas used as fuel, with all CO_2 captured post-combustion from the flue gas.

Table 18: CO_2 capture locations and associated capture rate for SMR

CO_2 capture locations	CO_2 capture from stream (%) [Ref. 10]	Overall CO_2 capture rate (%) [Ref. 10]
Shifted syngas, upstream of hydrogen purification	~ 100	60
PSA tail gas, downstream of hydrogen purification	~ 100	60
Post-combustion, from flue gas	> ~95	>~ 95

With ATR and POX technology (also SMR if hydrogen rich fuel is used), CO_2 capture objectives can be met by maximising conversion of methane to CO_2 and hydrogen (including through the addition of a GHR step to increase reforming) and optimising CO shift sections, enabling process CO_2 capture from the hydrogen product stream, with no requirement for post-combustion capture:

- process CO_2 capture upstream of the hydrogen purification step. This stream will contain approximately 25 mol% CO_2 at high pressure. CO_2 removal efficiency of close to 100% from the stream should be expected using amine solvent
- process CO_2 capture from the tail gas from the hydrogen purification step. Capture from this location increases load on the hydrogen purification step, with capture from a low pressure stream containing typically greater than 70 mol% CO_2, based on no CO_2 capture upstream of the hydrogen purification step

Overall CO_2 removal rate is proportional to the degree of upstream conversion to CO_2. Carbon in the form of methane or carbon monoxide will either pass with tail gas from hydrogen purification (to fuel gas pre-heating in an ATR process) or will pass to the hydrogen product if the required hydrogen purity specification allows methanation to convert carbon monoxide to methane rather than removal.

An overall CO_2 removal rate of around 97% is expected to be achievable, where any fuel gas demands for process heating or steam generation can be met by hydrogen purification tail gas or hydrogen product rather than combustion of feed gas. [Ref. 10].

With POX hydrogen production technology, there is not typically a need for auxiliary fired equipment, and therefore no requirement for fuel. If purification of the hydrogen product is achieved through pressure swing adsorption, this will produce a tail gas stream, as shown on Figure 5, which becomes a by-product, not used within the hydrogen production process. This may be used as fuel elsewhere, and the considerations for the combustion of this fuel stream would be similar to those if it were used as fuel in the process, with decarbonisation objectives achieved through high conversion rates and CO_2 capture in the upstream process. If purification of hydrogen product is achieved through methanation, there is no tail gas resultant from the process, and an overall CO_2 removal rate of >99% can be achieved within the installation, although carbon monoxide converted to methane and remaining in the hydrogen product will form CO_2 on combustion of the product at the point of use.

Post-combustion capture from flue gases from combustion of fuel with low carbon content, such as hydrogen purification tail gas may not be feasible, and any small incremental benefit in increased CO_2 capture rate are likely to be outweighed by the energy use, additional risks (including environmental impacts) and costs introduced by the addition of a post-combustion capture system.

4.6.2. Process CO_2 capture

The shifted syngas is fed at high pressure to a CO_2 capture unit, where CO_2 is separated from hydrogen. The CO_2 capture unit produces a CO_2 rich gas, which is compressed to the pressure required for export from the site. Downstream of compression, or at an optimal pressure within the compression train, the CO_2 is dehydrated and treated as necessary to meet the export specification.

Process CO_2 capture technologies include[12]:

- state of the art chemical solvent absorption technologies, predominantly amines
- physical solvent absorption
- low temperature (cryogenic) bulk CO_2 separation, relatively novel in the context of large scale hydrogen production, and requiring combination with other CO_2 capture technologies, but with potential to capture a portion of the CO_2 without the heat requirement for solvent regeneration and with the ability to deliver CO_2 at higher pressure than solvent absorption processes, reducing downstream compression requirements.

[12] The most commonly used chemical, physical, and cryogenic solvents are listed in Section 3.2. Information about each solvent can be directly found in the technical review completed by IEAGHG [Ref. 10].

The International Energy Agency Greenhouse Gas R&D Programme (IEAGHG) evaluated the process CO_2 capture rate for alternative CO_2 capture technologies from both shifted syngas and PSA tail gas in an SMR hydrogen production plant. The study concluded process CO_2 capture of PSA tail gas using MDEA and cryogenic + membrane separation were comparable, with their overall CO_2 capture rate being 54% and 53% respectively [Ref. 8]. This is also comparable to the CO_2 capture rate quoted in section 4.6.1.

- vacuum swing adsorption (VSA)

Vacuum swing adsorption (VSA) is a novel CO_2 capture technology which has been implemented at Air Products' Port Arthur hydrogen production facility in 2013 and is the first commercial scale SMR with VSA CO_2 capture [Ref. 5]. A key reason that VSA technology was selected at Port Arthur over the alternative of chemical solvent absorption was the additional steam requirement to regenerate the amine solvent, which was, in that case, a significant energy burden on the system and difficult to accommodate [Ref. 5].

Various independent studies have been conducted on CO_2 capture in hydrogen production, considering different hydrogen production technologies, CO_2 capture technologies and locations. VSA CO_2 capture technology was assessed in studies by the Royal Society of Chemistry [Ref. 9] and by Industrial & Engineering Chemistry Research (I&EC Research) [Ref. 14, 15].

4.6.3. Post-combustion CO_2 capture

Chemical absorption is the most suitable technology for post-combustion CO_2 capture due to the flue gas conditions, for example, low pressure and low CO_2 concentration. Such post-combustion CO_2 capture uses a recirculating chemical solvent, typically an amine solution, which reacts chemically with the CO_2 at in an absorber tower, with the reaction reversed at elevated temperature in a regenerator tower to release a concentrated CO_2 stream. It includes the following main steps:

- **Flue gas conditioning** – Cooling of the flue gas, typically by direct contact with recirculating cooled water in packed tower. It may also be necessary to boost the pressure of the flue gas using a fan / blower, to provide sufficient pressure to overcome the pressure losses through the system, but this would be dependent on the application. Pre-treatment to remove contaminants such as NOx may also be necessary, for example, with selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR), particularly considering potential of these contaminants to react with amine solvents producing degradation products.
- **CO_2 absorption** – Flue gas from the direct contact cooler is passed to an absorber tower containing packing in which CO_2 is absorbed in counter-current contact with the

amine solvent. There may be a requirement for inter-cooling within the absorber system. After CO_2 capture, the flue gas passed through a water wash section to remove any droplets or volatile solvent before being discharged to atmosphere. The wash water section also allows control of the flue gas temperature and water balance to reduce water make up needs. The decarbonised flue gas will leave the water wash section at relatively low temperature, saturated with water, and the impact on dispersion characteristics and visible plume formation need to be considered.

- **Solvent regeneration** – Solvent, rich in CO_2, from the base of the absorber tower is pumped to a regeneration system. Heat is exchanged with hot lean solvent, increasing the rich solvent temperature and reduce external heating and cooling requirements for regeneration. The rich solvent is fed to a regeneration column which includes a stripping section below the feed, in which solvent is contacted with water vapour produced by a reboil system, at the column base. The column also includes a rectification section above the feed, in which the vapour, carrying the CO_2 is contacted with water produced by an overhead condenser and reflux system. A concentrated CO_2 stream is produced from this overhead system, suitable for routing to CO_2 compression system. In some proprietary processes, additional features are included for heat recovery and efficient solvent regeneration. Amine solvents react with some flue gas components to produce heat stable salts and other by-products, levels of which need to be controlled by bleeding off a portion for processing to reclaim the solvent.
- **Lean solvent** – Lean solvent from the regeneration system is pumped, cooled, and circulated to the CO_2 absorber tower. A lean solvent storage tank is normally incorporated to provide buffer storage. As amine solvents react with oxygen and other contaminants in the flue gas, there is a need for thermal reclamation to maintain solvent quality, in which a slipstream of lean solvent, containing degradation products including heat stable salts, is fed to a reclaimer unit. This is typically a column operating at high temperature, from which water and solvent can be distilled, leaving a residue containing the separated degradation products for disposal off-site.

For SMR hydrogen production technology, post-combustion CO_2 capture is required from the flue gas at the SMR furnace outlet (Fig.3). For ATR hydrogen production technology, post-combustion CO_2 capture may be an option for auxiliary fired heaters / boilers, although the use of low carbon content fuel such as hydrogen purification tail gas make this unlikely to be optimal (Fig.4). CO_2, CO, and methane in the hydrogen purification tail gas should be kept as low as practical to minimise CO_2 in combustion products when the tail gas is used as a fuel source elsewhere in the process.

4.7. Hydrogen purification

Hydrogen product from the CO_2 capture unit can be further purified in a hydrogen purification unit before being compressed (if necessary) to the pressure required for downstream distribution / use.

This process step primarily removes unreacted carbon monoxide from the hydrogen product, but also other components requiring removal to meet the process specification – for example, methane, CO_2 and nitrogen. In modern conventional hydrogen production plants, all hydrogen purification, including CO_2 removal is undertaken in the PSA unit.

Technologies may include pressure swing adsorption (PSA) and/or a methanation step to convert any residual carbon monoxide to methane in the final hydrogen product stream, as long as the methane content still meets the hydrogen specification. Methanation is an exothermic reaction that takes place at 300°C in a reactor filled with a nickel-based catalyst. The chemical reactions occurring in methanation are shown in Table 19.

Table 19: Methanation chemical reactions

Chemical reactions		
Methanation (1)	$CO + 3H_2 \rightleftharpoons CH_4 + H_2O$	ΔH_{298} = -206 kJ/mol
Methanation (2)	$CO_2 + 4H_2 \rightleftharpoons CH_4 + 2H_2O$	ΔH_{298} = -165 kJ/mol

Some of the hydrogen is used in producing methane (which has calorific value) and water (which does not).

Any heat produced through the reaction would typically be recovered through a feed / product interchanger to maximise energy efficiency. The temperature rise over the methanation reactor is normally small due to the relatively low levels of CO and CO_2 in the feed to the unit.

PSA introduces a relatively small loss of hydrogen with the tail gas, but this is in any case normally used as fuel within the process, and this can help meet overall heat balance for a SMR reformer furnace or auxiliary heaters or boilers in ATR processes.

4.8. Heat and condensate recovery

The cooling of the syngas stream leaving the reforming process and the exothermic CO shift reaction generate heat and steam, which may be recovered through a waste heat recovery process to integrate with other processes (for example, solvent regeneration in the carbon capture step and/or hydrogen purification step or to preheat boiler feed water) and maximise energy efficiency.

Process condensate resulting from steam condensation is normally recovered and reused after necessary treatment to remove any residual impurities such as methanol, ammonia etc. The process condensate may beneficially supplement boiler feed water supply in the steam generation system or used elsewhere in the process.

4.9. Power

A co-generation unit might be implemented to assist steam and power supply to the hydrogen production / CO_2 capture process and may also enable any surplus steam and power production for export. The addition of a co-generation plant to the hydrogen production and carbon capture processes may improve the overall energy efficiency of the plant while reducing the overall impact to the environment, for instance, were it to be fuelled with a portion of the hydrogen product gas.

A standalone SMR without CO_2 capture may produce excess steam, which is typically exported to industrial users. With addition of post-combustion capture, the excess steam can be used to generate power via a steam turbine, with the resultant low pressure steam used to provide heat required for the CO_2 capture solvent regeneration. The power produced can be used to satisfy all of the overall stand-alone unit's power requirements for pumping, compression, etc. With inclusion of a convective reformer (GHR), the process can be balanced in terms of steam production and demand.

For an ATR with CO_2 capture, the CO shift and cooling of the process gas will generate excess steam which can be used to produce power and part supply the plant power requirement. With inclusion of a convective reformer (GHR), the process can be balanced in terms of steam production and demand.

For the POX process with CO_2 capture, excess steam is produced which can be used to generate power, again part supplying the plant power requirement.

Hydrogen production may be integrated with co-generation to improve energy efficiency, operational flexibility and to minimise impact to the environment, with the potential for higher thermal efficiency [Ref. 5].

5. Environmental considerations and guidance

Although it is recognised that hydrogen production technology will be selected considering a range of commercial, technical, and economic factors, the selection of technology and plant configuration should account for the environmental performance, considering energy efficiency, resource use, and impact on CO_2 capture methods and performance.

Another key consideration is on the requirement for electrical power to support the process. SMR processes, for example, can typically produce an excess of high pressure steam, used to generate power or drive mechanical equipment and produce low pressure steam for CO_2 capture solvent regeneration. The main power demands in this case are in CO_2 capture and compression. Other hydrogen production processes such as GHR + ATR may consume less feed gas, but do not have the same excess of high pressure steam to produce power, and have additional power demands for production of oxygen. The source of electrical power supply is an important consideration, but the carbon intensity of imported electrical power is outside the scope of this assessment.

5.1. Feed gas supply

Depending on the source of feed gas to the process, it will meet gas network entry or local refinery fuel gas specifications, with limitations on sulphur, mercury, and heavy hydrocarbon content.

Any CO_2 in feed gas will be removed later in the process, together with CO_2 produced in the hydrogen production process. Nitrogen in feed gas may also require removal from the hydrogen product in the hydrogen purification process to meet hydrogen inert content specification, depending on the quantity in the feed gas.

The range of composition is important for example in order to specify the desulphurisation and pre-reforming stages. The full compositional range should be specified, particularly in the case of refinery fuel gases which can typically be from several sources.

Sulphur (SO_2) emission sources to air (through combustion of fuel gas) should be limited through the use of a low sulphur feed gas or by pre-treating the feed gas to remove the sulphur-containing species.

5.2. Feed gas desulphurisation and pre-reforming

Feed gas treatment depends on feed gas contaminants, sensitivity of reforming and CO shift catalysts to poisoning and deactivation, and hydrogen product specifications. Technologies for sulphur removal and mercury removal are described in section 4.1.

This is typically achieved through hydrogenation of sulphur containing compounds and their removal on a catalyst adsorbent. As such technology is suitable for trace removal, where possible, the removal of sulphur components from the feed gas to the hydrogen production process should be maximised in upstream facilities to avoid excessive use of adsorbent catalyst, requiring disposal / recycle.

Catalyst selection should be made considering environmental performance, accounting for:

- any required pre-treatment to avoid poisoning, to minimise waste and associated treatment
- prevention of any dust emissions, where applicable
- ability to recover/recycle the solids/metals from the spent catalyst waste
- handling of spent catalyst for environmentally safe recovery / recycling / disposal

Requirements for pre-reforming, in which ethane and heavier hydrocarbons are broken down at a relatively low operating temperature, to avoid production of carbon residues in the methane reforming step, are also specific to the feed gas source and composition. In the adiabatic pre-reformer, endothermic reforming reactions convert heavier hydrocarbons and some of the methane to CO and hydrogen, while exothermic CO shift and methanation reactions will also reach equilibrium, giving a mixture of methane, CO_2, carbon monoxide and hydrogen to the downstream reformer.

As the pre-reforming step transfers reforming duty out of a SMR, it allows a reduction in the reformer size and fuel gas consumption. Incorporation of a pre-reforming step can therefore be considered, to optimise the overall environmental performance, for example to optimise energy efficiency and to minimise NO_x emissions to air. In increasing the degree of pre-reforming, consideration needs to be given to the steam balance for reforming with CO_2 capture, and steam required for the steam turbine and CO_2 capture solvent regeneration reboiler. Where the feed gas is low in heavier hydrocarbons, for example, where the gas is processed upstream for recovery of natural gas liquids, there may be little or no advantage in pre-reforming.

5.3. Reforming and CO shift

In the reforming and CO shift sections, methane conversion to hydrogen, carbon monoxide and CO_2 minimising methane slip, and the carbon monoxide conversion to CO_2 should be optimised considering the overall CO_2 capture target, and the impact on downstream processing to meet the hydrogen product specification.

In the case of oxidation reactions in the process, equipment design, and operating parameters should be optimised to minimise risk of soot formation. In the case of autothermal reforming, the potential to destroy any identified soot precursors in the catalyst bed to avoid soot formation should be considered (reference earlier section 4.3.2). The need for soot removal, for example, in the case of non-catalytic partial oxidation with high operating temperatures, to protect downstream systems is to be considered, along with disposal requirements.

CO shift technology selection should consider the environmental performance:

- to maximise energy efficiency, particularly through best heat integration with the overall hydrogen production and CO_2 capture processes
- to minimise the duration of start-up operations and associated emissions to air from flaring
- to minimise production of wastes

A single step CO shift process may be considered in place of a more conventional high temperature / low temperature shift process, with isothermal conditions achieved through reactor cooling with recovery of heat. A key driver for this is in overall heat integration and efficient use of recovered heat, as long as sufficient conversion of carbon monoxide to CO_2 is achieved. This also avoids use of chromium catalyst needed for high temperature shift, minimising waste, and reduces potential for catalyst damage, methanation reactions, and Fischer-Tropsch reactions (for example, producing methanol which would condense with the water downstream), which can occur in high temperature shift processes if the steam to carbon ratio is too low [Ref. 1].

As high steam to carbon ratios will be employed in any case, to maximise CO_2 conversion and capture rates, risk of over-reduction of catalyst is low, and the benefits of the isothermal reactor will be weighed up by the designer against the requirement for a more complex multi-tube boiling water cooled reactor.

Methods for environmentally safe disposal and recycle / recovery of catalyst materials, should be addressed.

5.4. Process CO_2 capture from hydrogen product

Technology for CO_2 capture from the hydrogen product stream will typically be through absorption in a circulating chemical solvent, with regeneration of the solvent through reduction of pressure and heating to liberate CO_2.

The solvent should be selected, and parameters optimised within CO_2 removal system, to maximise energy efficiency and capture performance:

- lean solvent conditions and absorber system design for high degree of CO_2 capture to meet overall carbon capture objectives and reduce load on downstream hydrogen purification
- operation of regeneration system to deliver CO_2 at as high a pressure as practical (with pressure limited by operating temperature considerations to avoid excessive degradation of solvent), and avoidance of excessive pressure loss in CO_2 product system, to reduce CO_2 compression power requirements
- optimisation of lean/rich solvent heat exchange to reduce reboiler heat requirements for solvent regeneration

Consider technologies which reduce heat requirements for solvent regeneration, such as producing a semi-lean solvent stream for bulk removal in the bottom section of the absorber. Such techniques increase overall solvent circulation and pumping requirements but reduce heat requirements for full thermal regeneration of the solvent.

Consider technology which allows recovery of CO_2 at higher pressure, for example, solvent systems with flash regeneration of a portion of CO_2 at intermediate pressure, the benefits of which are dependent on the operating pressure of the reforming process and CO_2 absorber.

Absorber design should minimise carry-over of solvent, for example, through water wash and/or demisting, to minimise impact on the downstream hydrogen purification process and associated product and off-gas streams.

The overhead condenser / reflux system and section above the feed on the solvent regeneration column will minimise potential for solvent to reach the CO_2 product. Requirements for continuous purge from the reflux system to avoid build-up of components such as methanol which may be co-produced in the hydrogen production process should be considered, such that this can be managed within effluent treatment facilities.

Consider low temperature bulk separation of CO_2, with condensation and separation of a portion of CO_2 for delivery at elevated pressure. This has potential to reduce load on the downstream solvent-based system, and its associated heat requirements, and also reduce CO_2 compression requirements. Pre-treatment of feed gas to a low temperature separation will be required to remove water which would otherwise freeze in the process.

Requirements for CO_2 venting when downstream systems are not available should be considered, including requirements for an elevated local vent stack designed to optimise dispersion. Potential for atmospheric emission of solvent or associated substances should be low in such circumstances, but measures taken to mitigate this, such as ensuring continued operation of the regenerator overhead condenser and reflux system, should be identified.

Continuous CO_2 venting should not be planned as a normal operating mode, but rather when required in transient operation for control and to avoid wider disruption of the process, or when required temporarily in emergency operation. Where venting is required from high pressure CO_2 systems, where there is a significant cooling effect on pressure reduction, the measures taken to ensure adequate atmospheric dispersion should be identified.

5.5. CO_2 capture strategies specific to steam methane reforming

In the steam methane reforming process, process heat is provided by external combustion in a reformer furnace. Typically, a portion of the feed gas is used as fuel, with the majority of energy supplied from off-gas from hydrogen purification. Use of hydrogen, taken either before or after purification, is a potential alternative to use of feed gas as fuel. Otherwise, post-combustion capture is required to avoid the CO_2 emissions from combustion of hydrocarbons in the reformer as described below.

Within the SMR process, there is a need to remove CO_2 from the hydrogen product stream to meet the hydrogen quality specification. This can be achieved in two ways, and the optimal approach should be justified:

1) CO_2 removal combined with the hydrogen purification step, with for example a pressure swing adsorption unit delivering the CO_2 with the other impurities removed in an off-gas stream used together with feed gas to fuel the reformer furnace.

In this case, all carbon containing components from the syngas will be present as CO_2 in the flue gas from the reformer furnace and require post-combustion capture.

2) CO_2 removal upstream of the hydrogen purification system, with for example a solvent based CO_2 removal system, separate to other impurity removal from the hydrogen product.

In this case, near full removal of CO2 from the process stream can be achieved, with the carbon in the off-gas from the purification step (assuming pressure swing adsorption) limited to any methane and carbon monoxide slip from the upstream reforming and CO shift reactions.

With the conventional use of PSA tail gas (containing carbon monoxide) combined with feed gas to fuel the reformer furnace, post-combustion capture would still be required, with the difference made by upstream removal of CO_2 being mainly the impact on overall energy use for CO_2 capture, and the overall impact on hydrogen purification and CO_2 capture equipment sizing.

Given there are practical and economic limitations to the percentage post-combustion capture of CO_2, overall percentage CO_2 capture may be increased slightly by reduced reliance on the post-combustion capture step. However, with a 95% CO_2 capture rate potentially achievable in post-combustion capture from SMR flue gas [Ref. 6, 21], the increase in capture rate is small. Therefore, it is likely that applying post-combustion capture only, without a dedicated process CO_2 removal step upstream, will be the most economic option for achieving high CO_2 capture rates for most SMR-only based projects.

Together with use of hydrogen to fuel the reformer furnace, process CO_2 removal may avoid the need for post-combustion capture while meeting CO_2 capture objectives. In this case, the hydrogen production process would require capacity to produce both hydrogen product and hydrogen fuel gas. Any associated impacts of using fuel with higher hydrogen content on the SMR burners, and on NO_x formation in the reformer furnace would also need to be confirmed.

5.6. Post-combustion CO_2 capture from SMR furnace flue gas

Where post-combustion capture of CO_2 is employed, capture of 95% of the CO_2 from the flue gas is possible, and it expected this this will be maximised within practical and economic limits, with capture of greater than 95% potentially feasible [Ref. 6, 21].

In order to reduce emissions of CO_2, or polluting substances such as volatile components of the amine solvent and likely degradation products such as nitrosamines and nitramines to air, the post-combustion CO_2 capture system must be designed with high availability and with flexibility to handle expected variation in flue gas flow and conditions.

A guidance document for post-combustion capture (PCC), specific to CO_2 capture using amine solvents for power and CHP plants fuelled by natural gas and biomass, has been developed in parallel and independent of this guidance [Ref. 6, 21] and should be referred to for further information.

There are some differences in flue gas composition resulting from combustion of hydrogen rich fuel gas and natural gas in the reformer furnace, and the flue gases considered in the PCC guidance. Gas turbines for example operate with significant excess air for temperature control and the CO_2 is more dilute with higher oxygen and nitrogen content in the flue gas. Combustion of hydrogen rich streams can however give rise to high NO_x formation, and guidance provided on reaction of amine solvent with NO_x, and the requirements in some cases for upstream NO_x removal is relevant.

Start-up and shut-down operations are expected to be less frequent and hence a lesser consideration for hydrogen production from methane than for example in dispatchable power generation applications where post-combustion capture is also being considered. The requirements however for ramp-up and ramp-down of hydrogen production on CO_2 capture and environmental performance need to be considered.

Key environmental considerations to be addressed in the design of post-combustion capture from reformer furnace flue gas include:

- solvent selection, reflect the balance between CO_2 capture performance, associated energy requirements and potential atmospheric emissions, such as:
  - energy requirements for circulation and regeneration of amine solvent
  - reclaiming potential, to manage solvent quality and handle contaminants, removing degradation products including heat stable salts
  - potential for reaction with contaminants in flue gas, and impact on requirements for upstream conditioning of flue gas, for example, for NO_x removal
  - potential atmospheric emissions of solvent and associated degradation products such as nitrosamines and nitramines
  - proven performance through operational experience, or test programmes under realistic operating conditions
- atmospheric emissions, considering:
  - emissions of solvent components
  - emission of additional substances formed in the CO_2 capture system such as nitrosamines, nitramines and ammonia
  - emission of ammonia present in flue gas though slippage from upstream NOx removal
  - formation of further additional substances in the atmosphere from those emissions
- energy requirements:
  - heat – for example, low pressure steam for amine regeneration, with higher grade heat only for thermal reclaiming

  - power – for example, for pumping of amine and water streams; compression of flash vapour if applicable; and for flue gas fans / blowers which given large volumetric flows can add significantly to power requirements
- effluent streams:
  - the main effluent will be from purge of water condensed in cooling the incoming flue gas, in which any expected pollutants will need to be identified
  - potential for water to be recovered and reused within the process should be assessed
- all wastes requiring recycling or disposal must be identified, including:
  - waste from thermal reclaiming of amine solvent
  - solid wastes such as from amine filtration
- flue gas delivery and cooling requirements:
  - the process and layout should be designed to minimise requirement for flue gas fans / blowers which introduce additional power requirements, noise, and impact on availability. This will be particularly important where there are additional constraints in retrofit applications
  - flue gas cooling will typically be thorough direct contact with water in a packed tower, with the circulating water cooled against air or cooling water. Condensation of water from the flue gas will require continuous purge from the circuit. Impact of any water carryover from the direct contact cooler on the downstream CO_2 removal system, such as contamination of the amine solvent, should be assessed, with measures incorporated to eliminate carryover of water droplets as appropriate
- avoidance of excessive pressure drop through the flue gas cooling and absorber system
- flue gas contaminant removal for effective operation of the capture system should be identified:
  - SO_2 – typically managed through removal of sulphur to very low levels upstream of hydrogen production, and potential to remove in combination with direct contact cooling to be considered if required
  - NO_x – as this has potential to form stable nitrosamines with some solvents, upstream removal may be required, depending on the selected solvent
  - expected levels of contaminants in flue gas will need to be identified for the specific fuel gas composition and combustion conditions, considering use of feed gas, hydrogen purification off-gas or hydrogen product as fuel, in conjunction with proposed burner technology and combustion air flow
- absorber outlet conditioning, including:
  - design of wash sections, typically using water, to capture droplets of solvent and volatile components. This will typically control overall water balance with recovery of solvent into the process

- once available emissions reduction techniques have been incorporated, consider the need to heat flue gases from the absorber to improve dispersion, for example through heat exchange with hot flue gas upstream of the direct contact cooler, and the impact this has on any additional heat requirements, flue gas pressure balance and need for fans / blowers to boost flue gas pressure

5.7. CO_2 capture rate

A design CO_2 capture rate of 95% or greater is expected to be achievable for the hydrogen production and CO_2 capture routes considered for new plant:

- for SMR hydrogen production with post-combustion capture, this is consistent with expectation for CO_2 capture using amine-based technologies for power and CHP plants [Ref. 6, 21]
- for ATR with GHR, SMR with GHR, or POX hydrogen production processes, the 95% or greater CO_2 capture rate is dependent on high conversion of the methane to CO_2 through the reforming and CO shift sections, and near full removal of CO_2 from the hydrogen product, both of which are considered feasible

If a design CO_2 capture rate of less than 95% is proposed, justification will need to be provided by the applicant. For retrofit applications, there may be additional limitations on achievable CO_2 capture rate due to the constraints presented by existing facilities.

In operation, the actual CO_2 capture rate may vary, depending on the operating regime.

<u>Decarbonisation readiness and future proofing</u>

This applies to England and Wales only. It does not apply currently to Scotland and Northern Ireland.

There was a call for evidence by BEIS and the Welsh Government on decarbonisation readiness from July to September 2021.The government is currently analysing the results (correct as of July 2022).

[Decarbonisation readiness: call for evidence on the expansion of the 2009 Carbon Capture Readiness requirements - GOV.UK (www.gov.uk).](https://www.gov.uk)

The consultation includes the proposal that the requirement for all combustion processes (with no de minimis) to be decarbonisation ready be included in the Environmental Permitting Regulations (England and Wales) 2016.

There are some streams, for example, the flue gases from combustion of residual (tail) gas from the hydrogen purification process with a relatively high CO_2 concentration which may need to be decarbonised in future and should therefore be made decarbonisation ready by maintaining the necessary space and technical retrofit capability for future carbon capture.

<u>Carbon in hydrogen product</u>

It is noted that any CO, CO_2 or CH_4 or other carbon containing compounds as allowed by the product specification in the hydrogen product will be emitted to the environment as CO or CO_2 (assuming that the hydrogen product enters a combustion process at its point of use and that the carbon-containing compounds undergo conversion during combustion to CO or CO_2).

<u>Reporting of CO_2 emissions from imported electricity production</u>

The source of imported electricity and any associated CO_2 emissions are not in scope of the permitting assessment for an IED installation.

These emissions are accounted for elsewhere in the energy system. [Ref. 23].

5.8. Hydrogen product purification

Hydrogen purification requirements will depend on specified hydrogen product quality and impurities present following reforming, CO shift and CO_2 capture steps.

It will be necessary to consider:

- nitrogen and argon – present in feed gas or oxygen supply
- methane – which is not converted to carbon monoxide in the reforming section
- carbon monoxide – which is not converted to CO_2 in the reforming or CO shift sections
- CO_2 – which is not removed in the CO_2 capture section
- water – with the hydrogen stream saturated with water following CO_2 capture

Where the hydrogen product gas specification allows, and particularly where it is intended the hydrogen is blended with methane for downstream distribution, methanation (conversion of carbon monoxide to methane) could be considered as an alternative to separation of impurities. In this case, it is likely there will remain a requirement for dehydration to meet moisture specification, with methanation reaction introducing additional water.

Shutdown procedures for methanation reactors to prevent formation of toxic nickel carbonyl from reaction of CO with the nickel catalyst at lower temperatures will need to be employed in line with operating experience and established procedures.

Where hydrogen is produced with the intention of blending externally with natural gas, the impact of blending on the overall specification should be considered, with dilution of impurities, and ability to relax hydrogen purity to enhance energy efficiency and reduce / eliminate production of low pressure / low calorific value off-gas streams.

5.9. Off-gas production from hydrogen purification

Off-gas produced from hydrogen purification will be rich in hydrogen (from depressurisation and purge of the adsorber vessels) and will contain nitrogen from feed gas, argon from oxygen supply, and any methane, CO, and CO_2 that is not converted / removed upstream. The off-gas is normally used as fuel gas.

In the case of SMR with post-combustion capture, the amount of methane, carbon monoxide and CO_2 slip with the off-gas is largely an economic decision, as feed gas, containing carbon, is in any case introduced as supplementary fuel to the reformer furnace to satisfy heating requirements. There is an argument for avoiding high levels of methane or carbon monoxide slip through the process, as this increases the amount of gas being processed, however the optimum conversion rates may be lower than in other processes. Conversion rates in the process should be optimised considering environmental impacts of excessive slip of methane or carbon monoxide, such as on overall energy use.

In the case of processes with ATR or POX reactions, which do not employ post-combustion capture, slip of methane or carbon monoxide from the reforming and CO shift stages removed in hydrogen purification will end in the off-gas used as fuel and hence will represent uncaptured CO_2. Conversion rates in the process should be optimised to meet CO_2 capture objectives balanced with other environmental performance factors, such as overall energy use.

For POX based hydrogen production, there is potentially no requirement for combustion in auxiliary boilers or fired heaters, and off-gas produced from hydrogen purification is not required to meet the fuel balance. In this case, a use for the off-gas outside of the hydrogen production facility would need to be found, or the hydrogen production facility design adapted to utilise the off-gas for generation of heat or power, for example, in superheating of the steam generated in the process.

5.10. Heat integration and process cooling

Within the hydrogen production process, heat integration will typically be through gas / gas exchange, including in gas heated reformer where used; or through heat recovery for steam generation and superheating, including demineralised and boiler feed water heating.

Heat recovered through process cooling downstream of the reforming section, to condition the temperature for CO shift reaction, is at high grade and can be used for both direct heat integration within the process and producing steam at higher pressure levels for use in the process.

Heat recovered in condensation of water downstream of the CO shift reactor will be at lower grade, but at suitable temperature for use in CO_2 capture process using amine solvents. Recovery should be optimised through a suitable medium such as low pressure steam, or through direct heat transfer with syngas, to suit the CO_2 capture process, thus providing an opportunity for improved overall thermal efficiency.

There will ultimately be a need to cool further against ambient air or cooling water, but opportunities should be maximised to use the heat, for example in heating demineralised and boiler feed water.

Selection of ambient cooling medium – for example, air cooling, indirect sea water cooling, open (evaporative), closed or hybrid cooling circuits – should account for any impact of cooling temperature on process performance or energy efficiency, such as intercooling temperature on power requirements for compression.

Where the hydrogen production process has potential to produce excess high pressure steam, consideration should be given to how this is used most efficiently to generate electrical power or drive mechanical equipment such as compressors within the process. Heat integration to make best use of lower grade heat, as described above, may provide additional opportunities for more optimal use of high pressure steam.

Regarding heat recovery from CO_2 compression, the following references are relevant for heat recovery options from CO_2 compression trains.

These indicate that there is potential for at least 22% of compressor electrical power input to be recovered via cooling water from multi-stage compressor intercoolers and use of organic rankine cycle.

See [Ref. 24] p. 11 final paragraph of section 4, which also references [Ref.25].

5.11. Combustion

Requirements for fired equipment to provide heat to the process and generate steam is dependent on the reforming process. It can present a practical means of disposal of low pressure off-gas stream from hydrogen purification, for example using tail gas from a pressure swing adsorption process as fuel and balancing overall process heat requirements. It introduces a source of atmospheric emissions.

For steam methane reforming, external combustion in the reformer furnace represents a significant source of atmospheric emissions, with heat requirements typically provided through combustion of a portion of the feed gas together with off-gas from hydrogen purification. In this case, management of combustion emissions should be considered alongside those relating to post-combustion CO_2 capture.

In the case of autothermal reforming, where the majority of heat is provided by reaction with oxygen within the process, there is a lesser requirement for heat from auxiliary furnaces or boilers and it is most likely that this can be satisfied by combustion of hydrogen rich off-gas streams or hydrogen product.

In the case of partial oxidation, no furnaces or boilers are required, and combustion products are not normally produced.

Hydrogen combustion produces higher flame temperatures than methane combustion and has potential for higher thermal NO_x formation from reaction of nitrogen and oxygen.

Where hydrogen or hydrogen enriched fuel gases are combusted, techniques to control flame characteristics and reduce NO_x formation should be considered. This may include specially designed burners, flue gas recirculation or heat exchange with fuel/air.

Variation of fuel gas composition, particularly hydrogen content, needs to be considered, including any requirements to switch between fuel gas sources. Start up and shut down operations should be considered, as PSA tail gas will not be available for example when the plant is ramping up to minimum flow, and any fuel will be taken from methane feed.

Other established techniques such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) may need to be considered if NO_x formation in combustion gases cannot be reduced to acceptable levels, considering environmental risk to air quality and any prescribed emissions limits.

The emission levels for the combustion equipment in the scope of the hydrogen production and CCS plant will need to be identified from the existing sources of statutorily applicable emission limits, including the following:

- Medium Combustion Plant Directive
- Industrial Emissions Directive, Annex V
- BAT conclusions and BRef for the refining of mineral oil and gas
- BAT conclusions and BRef for large combustion plant
- BRef for large volume inorganic chemicals (ammonia and fertilisers)

This in accordance with the type of combustion equipment, fuels proposed to be combusted, net rated thermal inputs, Best available techniques for control of emissions, and the conclusions of an environmental risk assessment, considering the dispersion of pollutants into air and the sensitivity of the relevant receptors.

The regulators will take a case by case decision on the applicable emissions limits, based on the elements outlined above and the most apt reference source of emission limits.

Given that supply of oxygen is required for some hydrogen production processes, additional oxygen production to support oxy-combustion may be considered. Removing the source of nitrogen from combustion air would avoid NO_x formation, but experience in design and operation of such combustion systems is limited, particularly for combustion of streams rich in hydrogen. Any nitrogen present in the PSA tail gas would also need to be considered, as fuel NOx would then still be formed, and this route may not be effective. Also the impacts of increasing the size of the ASU to supply additional oxygen would need to be considered.

5.12. Oxygen production

Oxygen purity should be optimised, considering both the impact on the specific power required for oxygen production and the impact on the requirements for removal of argon / nitrogen in purification of the product hydrogen. High purity (99.5 mol%) oxygen is typically achievable economically in large scale cryogenic air separation, the balance then being argon.

Co-production of nitrogen and argon should be considered where there is local demand, where this reduces overall energy requirements. Nitrogen may also be required routinely on site (for example, for blanketing following a trip, continuous purging, or purging following maintenance).

Energy consumption in the ASU should be optimised through flowsheet selection and efficient machinery selection. It is typical for oxygen to be pumped to the required delivery pressure, avoiding an oxygen compressor, with air being compressed and fed to the unit at multiple pressure levels. The ASU and associated air compressor design should be optimised around the oxygen purity and supply pressure requirements of the hydrogen production process.

Heat requirements for regeneration of adsorbers used for drying and purification of compressed air should be optimised, including the best technique for chilling the air to condense and separate water upstream.

Opportunities for recovery and use of heat from the air compression system should be considered if this can be matched with demand within the process, and if this is practical from a technical and commercial perspective, given that the oxygen may typically be supplied from a stand-alone plant by a third party.

The form of heat integration should be selected to avoid additional hazards (for example, through combining oxygen production and hydrocarbon streams). Operability considerations, such as start-up and cool down of the ASU while the hydrogen plant is not operating, would need to be taken into account.

Reduction of the number of compressor cooling stages to increase the compressor discharge temperature and grade of heat available is an option but will also impact compressor selection and increase compressor driver power requirements.

High availability of oxygen supply should be targeted, for example by having parallel equipment or a back-up supply, recognising that interruption of oxygen supply will impact the hydrogen production process, with any commercial and environmental consequences associated with restart following shutdown, such as venting or flaring. The capacity of liquid oxygen production, storage and vaporisation should be optimised to provide back-up to gaseous oxygen production accordingly.

<u>Heat available from air compression in oxygen production</u>

The air compression train in the ASU would typically incorporate large integrally geared compressors, with multiple stages and regular intercooling. In this design, the temperature is kept relatively low (less than 120°C). Unlike in the oxyfuel applications considered previously, there is a requirement to deliver oxygen at high pressure (above feed gas pressure) to the reactor, and there is a need for the air / cycle compressors to operate with a greater number of stages to achieve the delivery pressure.

To recover heat at a higher grade / temperature would require reduced intercooling. In this case heat could be recovered at higher temperature, and there would be more heat available. More power would be required to drive the air compressors due to increased volumes, and a different compressor design or technology would be required. Given the large number of ASUs in service, the compression equipment used is well established.

In the Shell POX (SBHP) process, for example, there would not be an identified use for the low- grade heat, as such heat is also available from the hydrogen production process. The heat could potentially be used in an organic rankine cycle to generate power, and it is expected this would generate less than 0.1 MW per MW of heat available at the lower grade level. It would be higher if the number of intercooling stages was reduced, although this increase would likely be more than negated by increase in the air compression power. With air compression for a 500 tonne/day Shell Blue Hydrogen Facility requiring around 30 MW of power, and requiring a similar amount of cooling, addition of an organic rankine cycle could potentially produce 2 MW of power. This could be assessed using cost-benefit analysis and would also need to take account of any implications for safety reliability and operability, for example.

In this example, 6% recoverable heat from the ASU compression system with an organic rankine cycle could be achievable and this could be higher with direct heat integration.

5.13. Water treatment for re-use

Water / steam is both consumed in the hydrogen production process and used as a medium for recovery and transfer of heat. Water is therefore condensed both from the steam being used as a utility and from cooling of streams within the process.

By-products of the hydrogen production process, such as methanol and ammonia, which are expected to be present in condensed water from the process should be identified and quantified.

A large proportion of water condensed in the process can be re-used, but there is a need to release some water to effluent to avoid build-up of dissolved solids or other impurities.

For condensed water that is to be reused following treatment, any processing requirements for contaminant removal to allow reuse need to be identified, and any effluents and emissions from the proposed processes defined.

Requirements to remove dissolved gases, including CO_2, from the boiler feed water to reduce corrosion should be identified together with associated emissions to atmosphere associated with this deaeration.

For condensed water directed to effluent, impurities need to be identified to allow an appropriate strategy to effluent treatment to be developed, together with any other effluents from within the facilities.

All waste water streams are to be identified, including process condensate and other effluents such as steam system blowdown, cooling water blowdown, rain water, oily water, water treatment effluent and water used for cleaning. Suitable segregation strategies and methods of treatment to meet discharge consent limits are to be defined.

Water consumption and volume of contaminated water should be minimised by through design of the hydrogen production process, optimisation of water management through segregation of contaminated water streams (from water wash, condensate) and of non-contaminated water streams (once through cooling, rain water).

Water treatment should follow the most apt source of emissions limits on a case by case basis, between the existing BAT conclusions for common waste water and waste gas treatment / management systems in the chemical sector (2016/902/EU) and BAT conclusions for the refining of mineral oil and gas (2014/738/EU) and the associated BRef.

5.14. Reliability and availability

Environmental impacts of equipment or systems being unavailable should be identified, with the need for redundancy, buffer storage, etc. considered, to reduce the frequency of the occurrence of other than normal operating conditions (OTNOC). A risk-based OTNOC management plan should be implemented which identifies potential scenarios, mitigation measures (for example, around design and maintenance of equipment critical to avoiding emissions), monitoring and periodic assessment.

Such impacts within the facility could include for example:

- disruption to operation, with flaring required on shutdown and subsequent start-up
- requirement for venting of captured CO_2, for example when downstream CO_2 compression, CO_2 conditioning or export route is not available. It should be an objective of the design to minimise flow / duration of CO_2 venting under such circumstances to maximise overall CO_2 capture rates
- requirement for short term turndown of hydrogen production and flaring of hydrogen if the downstream export route or demand is lower than minimum feasible hydrogen production rate
- loss of performance of emissions abatement systems

Target availability for systems critical to environmental performance should be established, with proposed configuration supported by reliability, availability, and maintainability assessments.

5.15. Flexible operation

Until sufficient hydrogen supply, hydrogen demand or hydrogen networks and storage capacity are established, hydrogen production plants may be required to provide flexible operation to balance variation in demand by hydrogen users.

It is expected that all hydrogen production plants will provide a level of flexibility, at least for example in terms of production capacity range.

The need for high levels of flexibility will affect design and operation, with impacts such as:

- a greater need for intermittent CO_2 venting and feed gas or hydrogen flaring
- greater periods of non-steady state operation with ramp-up and ramp-down of capacity
- a need for wider capacity turndown range
- more regular shutdown and start-up operations
- lower energy efficiency, with potential need for process simplification and reduced heat integration to improve operability
- reduced energy efficiency when operating at turndown or in non-steady state operation
- additional energy requirements for start-up
- reduced CO_2 capture rates, particularly for non-steady state operation
- increased emissions to atmosphere from combustion equipment when operating at turndown or non-steady state operation

Applicants should identify performance at steady-state across the proposed production capacity range from minimum turndown to maximum production.

Flexible operating scenarios, including ‘off-design’ scenarios, where environmental performance will be reduced, or where additional emissions are expected, should also be identified, with examples including:

- rapid changes in capacity
- demand for hydrogen below minimum turndown production capacity with the need for hydrogen to be temporarily flared
- start-up following enforced shutdown

Considering the plant flexibility requirements and associated operating scenarios, the measures taken to maximise environmental performance should be described by the applicant, including for example process and equipment design, selected equipment capacities, and process control strategies.

On the expectation that the flexibility needed from hydrogen production plants may reduce over time, the applicant should also demonstrate a strategy for maximising performance when such flexibility is not required.

5.16. Monitoring and measurement

5.16.1. Role of monitoring

A key requirement of monitoring of the hydrogen production / CO_2 capture process is to demonstrate that the emissions from the process are not causing harm to the environment. Monitoring is also required to demonstrate that resources such as feed gas, electricity and water are being used efficiently, that the CO_2 capture rate is as expected, and that the hydrogen and CO_2 products meet the necessary specifications for export.

Monitoring plans shall be included in the permit application for routine operation and for more extensive monitoring during the commissioning period. During the commissioning period, the operating envelope of the process will be established. Operation at this time may be outside the normal operating envelope, and it is important that the monitoring plan considers any risks, such as to air quality. On completion of commissioning, with operation within the established normal operating envelope, the monitoring plan for routine operation should be implemented.

In addition, for post combustion capture, the operator must demonstrate that the process is being managed to prevent (or minimise) the formation of degradation products, and that where they are formed (and may be released) they, and any capture solvent emissions, are abated to the appropriate level.

5.16.2. Monitoring emissions to air

Monitoring of emissions to air, will be required based on expected pollutants (for example, ammonia, amine compounds, SO_2, NO_x, carbon monoxide, and so on) with appropriate methods and measuring techniques employed.

Monitoring shall consider, for example:

- NO_x and carbon monoxide emissions from combustion
- SO_2 emissions from combustion where the fuel source contains sulphur
- ammonia emissions where SCR / SNCR is employed
- amine / amine degradation products and other volatile solvent emissions
- methane
- hydrogen [Ref. 26,27]

For combustion plant, monitoring is required to demonstrate compliance with the applicable emissions limits described in section 5.11.

The regulators will take a case by case decision on the monitoring requirements, based on the most apt monitoring principles and monitoring thresholds set out for individual pollutants in the BAT Conclusions for Refining of Mineral Oil and Gas or BAT Conclusions for Large Combustion Plant.

Where emerging techniques are used for hydrogen production with CO_2 capture, monitoring methods and standards may need to be developed. Proposals should be developed by the operator as part of the permitting activities.

Where post-combustion CO_2 capture is employed, for example using amine solvent, monitoring of relevant emissions of such as ammonia, volatile components of the capture solvent and likely degradation products such as nitrosamines and nitramines shall be included. Monitoring of specific pollutants arising from post-combustion capture may be by CEMs if available or periodic extractive sampling and where aerosol formation is expected must be isokinetic.

5.16.3. Monitoring emissions to water

Monitoring of emissions to water, will be required based on expected impurities (for example, ammonia, amine compounds, methanol, CO_2, and so on) with appropriate methods and measuring techniques employed.

Monitoring standards for discharges to water should follow the existing BAT conclusions for Common Waste Water and Waste Gas Treatment / Management System in the Chemical Sector (2016/902/EU).

5.16.4. Monitoring of CO_2 capture performance

Applicants should clearly identify how the CO_2 capture performance of the plant will be monitored.

CO_2 capture performance is expected to be monitored according to standards that are recognised under the UK ETS. Measurements required to monitor CO_2 emissions to atmosphere may, for example, include direct measurement of the flow and composition of fuel gas to combustion systems.

This, together with measurement of the flow and composition of feed gas, hydrogen product (including methane content where applicable) and CO_2 product streams, will allow monitoring of the CO_2 capture rate and CO_2 quality (considering any impurities that could impact downstream systems).

5.16.5. Monitoring of process performance

Key requirements for monitoring of process operations should be identified where these ultimately impact on environmental performance – including for example amine system performance, including monitoring of amine solvent quality such as amine concentration, pH and presence of degradation or corrosion products; amine temperatures; amine and wash water circulation rates; rich and lean amine CO_2 loading; and stripper reboiler steam rates.

Energy efficiency in the hydrogen production and CO_2 capture processes should be monitored through measurement of feed and product gas flows and electrical power consumption to calculate overall energy consumption.

Requirements for process performance monitoring, either online or offline, will also be a condition of the permit.

5.17. Flaring

Strategies to reduce flaring and associated emissions should be established, including:

- flaring rather than venting, where emissions cannot be eliminated and where practicable, to minimise emissions of higher global warming potential gases such as methane and hydrogen
- plant design to maximise equipment availability and reliability (per section 5.13)
- minimising emissions under start-up, shutdown, and abnormal operations. Means of achieving this include:
    - use of a flare gas recovery system with adequate capacity
    - routing gas that would be flared to alternative users
    - use of high integrity relief valves
    - other measures to limit flaring to other than normal operations
- managing production of off-gas and balance against requirements for fuel gas using advanced process control and so on
- special procedures to define operations including start-up and shutdown, maintenance work and cleaning

- robust commissioning and handover procedures to ensure that the plant is installed in line with the design requirements
- robust return-to-service procedures to ensure that the plant is recommissioned and handed over in line with the operational requirements
- flaring devices design to enable smokeless and reliable operations and to ensure an efficient combustion of excess gases when flaring under other than normal operations
- monitoring and reporting of gas sent to flaring and associated parameters of combustion

5.18. Venting and purging

The applicant should identify venting and purging requirements in each of the processes employed, noting whether either continuous or intermittent, and identifying pollutants expected to be present, including for example CO_2, carbon monoxide, methane, hydrogen, ammonia vapour or methanol vapour.

Requirements for continuous venting may include for example:

- water vapour from CO_2 dehydration systems using circulating tri-ethylene glycol
- deaeration of steam condensate / boiler feed waters
- gases from processing of waste water streams
- purge of tanks, vent or flare headers

Requirements for intermittent venting may include for example:

- CO_2 vented in abnormal conditions, such as when the downstream transportation and storage system is not available, or if the CO_2 does not meet the export specification
- venting needed as part of purging equipment as part of maintenance activities

For each emissions point, an environmental risk assessment shall be made, against the applicable Environmental Assessment Level (EAL), in accordance with the relevant Regulator’s standard methodologies. This should include justification for venting to atmosphere vs. routing to flare and identification any measures proposed to reduce emissions of pollutants or ensure adequate dispersion. Methane and hydrogen greenhouse gas emissions shall be eliminated as far as practicable.

5.19. Unplanned emissions to the environment

5.19.1. Loss of containment

Consideration should be given to the environmental hazards posed by possible accidents and their associated risks specific to the hazards of the materials used, the operation and maintenance of the plant and the processes involved. This should include the practicality of measures to reduce risks and hazards and to respond to any accidents. In comparing the effectiveness of techniques to prevent emissions, consideration should not be limited to looking at normal operations, but also at the possibility of unintentional releases.

In considering the composition of the fluids that could be released, potential for changes due to degradation during operation should be considered.

Strategies to the reduce the potential for loss of containment and minimise environmental impacts should be established, for example:

- use of special procedures and/or temporary equipment to maintain performance when necessary to manage special circumstances such as spills, leaks, and so on
- use of a risk based leak detection and repair programme where applicable in order to identify leaking components and to repair these leaks
- plant design to facilitate monitoring and maintenance activities by ensuring accessibility
- selection of high integrity equipment where available
- plant design to maximise inherent process containment features

5.19.2. Leak detection and repair

A leak detection and repair programme should be proposed, using industry best practice to manage releases from joints, flanges, seals and glands, and so on. The proposals shall be appropriate to the capture solvents and other fluids used in the process.

5.20. Noise

BAT is to be implemented for prevention or reduction of noise, with a plan for management of noise developed as appropriate to the local environment.

Noise reduction techniques to be considered where necessary to include use of acoustic insulation or enclosures or screening through use of embankments or walls.

Equipment generating noise should be identified at the design stage, and their environmental performance should be considered for intended operations, including:

- an environmental noise assessment
- a noise management plan
- plant design to consider the selection of enclosures of noisy equipment or operations
- plant design to consider the location of noisy equipment or operations
- plant design to consider the use of embankments to screen the source of noise
- plant design to consider the use of noise protection walls

6. Process performance parameters

The performance parameters summarised below are indicative of a range of typical technologies for hydrogen production with CO_2 capture.

These are provided for information, and to highlight key differences between alternative production technologies, and not as an expectation of minimum performance or exhaustive in terms of technology options.

Permit applicants / operators should provide these key performance parameters based on design expectations at the application stage. Subsequent reporting of performance during operation will allow data gathering and enable benchmarks to be established.

Data is provided for:

- GHR + ATR – Low Carbon Hydrogen (LCH™)[13] Process

Based on information provided by Johnson Matthey, with wider considerations from Progressive Energy.

This assessment is based on a feedstock with 89 mol% methane, 7 mol% ethane, 1 mol% propane, 0.1 mol% butanes, 2 mol% CO_2 and 0.9 mol% nitrogen. Hydrogen purification is via pressure swing adsorption to meet purity close to 100 mol% with the off-gas stream used to fuel an auxiliary heater and boiler. CO_2 capture from the process upstream of hydrogen purification, uses activated MDEA solvent. There is a requirement for the import of electrical power.

- POX (Non-Catalytic) – Shell Blue Hydrogen Process (SBHP)

Based on information provided by Shell Catalysts & Technologies.

This assessment is based on feedstock with 91 mol% methane, 5 mol% ethane, 2 mol% propane, 1 mol% CO_2 and 1 mol% nitrogen. Hydrogen purification is via methanation to meet purity > 98 mol% and avoiding production of an off-gas stream. CO_2 capture from the process

[13] LCH is a trademark of the Johnson Matthey Group of Companies

upstream of hydrogen purification, using proprietary ADIP-Ultra[14] amine solvent. This provides near 100% capture of carbon present as CO_2 in the process stream. With no atmospheric combustion of fuel required, there are no significant direct CO_2 emissions associated with hydrogen production. There is a requirement to import electrical power. Some carbon, in form of methane, remains in the hydrogen product following methanation, which will lead to a CO_2 emission by the end user. The contribution of methane slip with the product hydrogen is excluded in assessing heating value for energy conversion.

Note – a pressure swing adsorption (PSA) unit could be used in place of methanation, to produce a hydrogen purity close to 100 mol%. This would lead to a tail gas for which a beneficial use / disposal route would need to be identified.

- SMR + Post-combustion Capture (PCC)

Based on information from “Benchmarking State-of the Art and Next Generation Technologies”, prepared for BEIS by Wood [Ref. 20].

This assessment is based on feedstock with 89 mol% methane, 7 mol% ethane, 1 mol% propane, 0.1 mol% butanes, 2 mol% CO_2 and 0.9 mol% nitrogen. Hydrogen purification is via pressure swing adsorption to meet purity close to 100 mol%, with the off-gas stream used together with feed gas to fuel the reformer furnace. CO_2 capture is from reformer furnace flue gas only, with 90% CO_2 capture rate using proprietary amine solvent. Power requirements are in this case balanced with self-generation from high pressure steam from the heat recovery system.

The 90% CO_2 capture rate in this case is representative, although it is expected that a design post-combustion CO_2 capture rate of 95% will in most cases be feasible both technically and economically [Ref. 6, 21]. Justification shall be provided by applicants if a design CO_2 capture rate less than 95% is proposed.

[14] ADIP is a technology licensed by Shell

6.1. Process / energy efficiency

Table 20: Process / energy efficiency key performance parameters

Parameter	Description	Value GHR+ ATR+ PSA	Value POX+ Methanation	Value SMR+ PCC+ PSA	Units
Gross feed gas energy conversion	Energy content hydrogen product / energy content feed gas (LHV basis)	80.6	76.6 + 3.1 (Note 1)	67	%
Net feed gas energy conversion **(Note 2)**	Energy content of net hydrogen product / energy content feed gas (LHV basis)	70.5	70.5 + 3.1 (Note 1)	67	%
Electrical power consumption (Note 3)	Net power import after electrical power generation	8.8	5.6	0	MJ / kg H_2
Overall energy conversion	Energy content hydrogen product (LHV basis) / overall energy input (LHV basis & including power import)	76.1	73.2 + 3.0 (Note 1)	67	%
Water consumption (process)		3.8 (Note 4)	2.4 (Note 4)	5.3 (Note 4)	kg H_2O / kg gross H_2
Auxiliary heating duty	Thermal input if not covered in the above	(Note 5)	(Note 5)	(Note 5)	MJ/ kg H_2

Cooling duty	Heat rejected to cooling medium or air	(Note 6)	(Note 6)	(Note 6)	MJ/ kg H_2

The performance parameters included have each been developed on a different basis, and do not provide a fully like-for-like comparison.

Notes:

1) In the values shown for POX with methanation, 3.1% of feed gas energy retained in hydrogen product in the form of methane – i.e. converted from carbon monoxide/CO_2 as part of the purification step. This avoids use of pressure swing adsorption, with the loss of around hydrogen product in the associated tail gas stream, for which there is no requirement for use as fuel in the process.
2) The Net Hydrogen Product is equal to the Gross Hydrogen Product minus the amount of hydrogen that would be required to generate the imported electricity. This is assumed in the values shown here to be generated using a Combined Cycle Gas Turbine fueled by hydrogen with a 58.5% LHV overall efficiency (based on the top of range of the BAT-associated energy efficiency level for combined cycle gas turbines in the range 50-600 MWth from Table 23 of the Large Combustion Plant BAT conclusions, 2017. BAT Conclusions for large combustion plant
3) The electrical power consumption in each case is on a broadly comparable basis, although with some differences in assumptions, for example around CO_2 delivery pressure.
4) Water consumption is made up of water used in reaction to produce hydrogen and CO_2 plus any condensed water from the process that is not re-used and blowdown from the steam and cooling systems. The data provided by technology is unlikely to be on a fully comparable basis. Operators will need to justify their water consumption on site-by-site basis.
5) All heating duties are included in the feed gas energy conversion figures.
6) Duties include hydrogen rich product cooling, amine cooling in the CO_2 capture unit, flue gas cooling for post-combustion capture, and compressor cooling for CO_2 and air compression. The data provided by technology is unlikely to be on a fully comparable basis. Operators will need to justify their choice of cooling technique(s) and water use on site-by-site basis

6.2. Emissions

Table 21 – Emissions key performance parameters*

Parameter	Description	Value GHR+ ATR+ PSA	Value POX+ Methanation	Value SMR+ PCC+ PSA	Units
CO_2 emissions to air (from the installation)	CO_2 not captured or part of hydrogen product	0.3-0.4 (0.34 - 0.46) (Note 1)	0.0 (0.36) (Note 2)	1.0 (Note 3) 0.5 (Note 4)	kg CO_2/ kg Gross H_2 (kg CO_2 / kg Net H_2)
NO_x emissions to air*					kg / kg H_2
SO_2 emissions to air*					kg / kg H_2
CO emissions to air*					kg / kg H_2
Emissions to water – methanol*	To effluent treatment.				kg / kg H_2
Emissions to water – ammonia*	To effluent treatment.				kg / kg H_2

Parameter	Description	Value GHR+ ATR+ PSA	Value POX+ Methanation	Value SMR+ PCC+ PSA	Units
Emissions to water – CO_2*	To effluent treatment.				kg / kg H_2
Waste production*	For waste stream. Expressed over lifecycle, annually or per unit of hydrogen produced, as appropriate.				kg

The performance parameters included have each been developed on a different basis, and do not provide a fully like-for-like comparison.

*: Data which has not been provided here will be reported and verified during the operational phase of relevant installations. Emissions will be required to comply with all ELVs required under the relevant BAT conclusions.

Notes:

1) Based on ~100% CO_2 capture upstream of the PSA unit, with combustion of the remaining carbon monoxide and methane in the tail gas from the PSA unit to fire auxiliary heater and boiler without further abatement.
2) Based on ~100% CO_2 capture including methanation unit producing 98 mol% hydrogen product. The hydrogen product when combusted offsite will produce approximately 0.33 kg CO_2 per kg H2 product.
3) Based on 90% CO_2 post-combustion capture from reformer furnace flue gas.
4) Based on the expected 95% CO_2 post-combustion capture from reformer furnace flue gas.

6.3. Carbon capture performance

Table 22: Carbon capture key performance parameters

Parameter	Description	Value GHR+ ATR+ PSA	Value POX+ Methanation	Value SMR+ PCC+ PSA	Units
Gross basis					
CO_2 Capture	From Process (Pre-Combustion)	8.4	8.4	0	kg CO2 / kg gross H_2
CO_2 Capture	Post-Combustion	0	0	9.2/9.7 (Note 1)	kg CO2 / kg gross H_2
Total CO_2 Capture	Overall Pre- and Post-Combustion	8.4	8.4	9.2/9.7 (Note 1)	kg CO2 / kg gross H_2
Net basis					
CO_2 Capture	From Process (Pre-Combustion)	9.6	9.1	0	kg CO_2 / kg Net H_2
CO_2 Capture	Post-Combustion	0	0	9.2/9.7 (Note 1)	kg CO_2 / kg Net H_2
Total CO_2 Capture	Overall Pre- and Post-Combustion	9.6	9.1	9.2/9.7 (Note 1)	kg CO_2 / kg Net H_2

Parameter	Description	Value GHR+ ATR+ PSA	Value POX+ Methanation	Value SMR+ PCC+ PSA	Units
Total CO_2 Capture Efficiency	Carbon Captured / Carbon in Feed Gas	95-97	96-97 (Note 2)	90/95	% kg carbon captured / kg carbon in feed gas
Total CO_2 Capture Heat requirement	Net Heat Input to CO_2 Capture Process	Note 3	Note 3	Note 3	MJ / kg CO_2
Total CO_2 Capture Power requirement	Net Power Input to CO_2 Capture Process	Note 4	Note 4	Note 4	MJ / kg CO_2 captured
CO_2 Compression Duty requirement	For Delivery to Pipeline	Note 4	Note 4	Note 4	MJ / kg CO_2 captured

The performance parameters included have each been developed on a different basis, and do not provide a fully like-for-like comparison.

Notes:

1) Lower value based on 90% CO_2 capture, higher value based on 95% CO_2 capture.
2) Based on ~100% CO_2 capture upstream of a methanation unit producing 98 mol% hydrogen product. The hydrogen product will contain 3 to 4% of the carbon from the feed gas. There are no direct CO_2 emissions from the hydrogen production or methanation units.
3) This is included in the feed gas energy conversion rates in Table 20.
4) Included in the power requirements in Table 20.

7. Summary of stakeholder input

This guidance document includes inputs from engagement with key stakeholders, including hydrogen production and carbon capture technology providers, hydrogen project developers and operators.

A questionnaire has been compiled to address the most relevant environmental aspects specific to hydrogen production from methane and CO_2 capture technologies (Appendix A).

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Appendices

Appendix A – Stakeholder engagement questionnaire

Requested information

Stakeholders are requested to provide any information they consider to be of value in assessing BAT for hydrogen production with CO_2 capture, and in particular information addressing the questions below.

If there is information available to stakeholders which is commercially sensitive / confidential and cannot be shared for the purposes of this research, please advise.

The points below consider hydrogen production through forms of autothermal reforming or partial oxidation. In the case of steam methane reforming, some questions will not be applicable, but we are interested also to understand technology and proposals for post-combustion CO_2 capture and atmospheric emissions from the reformer, overall energy balance and utilisation of excess steam.

A. Overall material balance

1. What is the typical hydrogen production capacity range considered, per process train?
2. What are the considerations in scaling the technology to higher capacity or for smaller scale hydrogen production?
3. Would it be possible to share block flow diagrams or simplified process flow diagrams? If so, could these be disclosed in the research report?
4. What is the consumption of feed gas (converted to hydrogen, CO_2, and fuel streams) and water per unit of hydrogen production? How much oxygen is generated to supply the process?
5. How is the methane conversion to CO and CO_2 in the reforming section balanced with requirements for CO shift – i.e., degree of conversion?
6. What technologies are proposed for CO shift, for optimal conversion to CO_2, balanced against CO removal duty in downstream hydrogen purification?
7. What level of sulphur contaminants can typically be allowed in the feed gas, what technologies are used for sulphur removal, and in what form is the sulphur captured and disposed of?
8. In the specific case of non-catalytic partial oxidation, how is it proposed sulphur is managed to meet product specifications in terms of upstream or downstream removal?

9. What is the proposed purity of oxygen supply, representing the balance between the need to remove inert components from the hydrogen product and the associated energy requirements for oxygen production?
10. Have applications been identified where methanation could be an appropriate alternative to pressure swing adsorption to meet the hydrogen product specification?
11. How is it proposed to utilise:
    a) Tail gas from hydrogen purification, which depending on the upstream process performance will contain carbon as CO_2, CO, and methane?
    b) Flash gas from CO_2 capture?
12. How is it proposed condensed water from the process is reused and what are effluent streams from process, steam, and cooling systems?

B. CO_2 capture

1. What technologies are proposed for CO_2 capture from the hydrogen rich product?
2. How can the CO_2 capture system be designed to reduce energy requirements – for example, use of split stream absorption, heat integration, flash, etc. in the case of chemical absorption processes.
3. Have other technologies been identified that could reduce energy use or environmental impacts, and what are the obstacles to implementing these?
4. Has the impact of CO_2 capture technology on the CO_2 delivery pressure and downstream CO_2 compression requirements been assessed?
5. Have alternative locations in the process for CO_2 capture been evaluated (to suit technology selection) – for example, removal upstream of hydrogen purification vs. removal in the hydrogen purification unit followed by separation from the purification unit tail gas?
6. Where auxiliary boilers or fired heaters are used, with carbon-containing fuel, has the case for post-combustion carbon capture been assessed?
7. What are the impacts and the implications on emissions to all media under the following operations?
    a) Changes in hydrogen demand
    b) Partial shutdown (for example, of CO_2 export route or hydrogen export route) either planned or unplanned
    c) Interim non-availability of CO_2 transportation and storage infrastructure if timescales for development differ

8. Are there any specific provisions for CO_2 capture readiness in the case of staggered development, i.e., hydrogen production being developed first followed by CO_2 capture at a later stage?
9. Are there any specific provisions for interim operations and associated emissions, prior to the availability of the CO_2 export and storage infrastructure, if this were economically viable?

C. Energy balance

1. How are the overall energy requirements satisfied for hydrogen production and CO_2 capture, including external power and heat requirements and their generation?
2. How are heat exchange and heat recovery systems optimised with the steam system to provide process heating needs including for CO_2 capture?
3. What are the needs for auxiliary boilers or fired heaters, for gas pre-heating or to meet steam balance, and what fuel is proposed for these duties – for example, feed gas, hydrogen rich gas, tail gas from hydrogen purification or hydrogen product?
4. What other potential integration opportunities are there between hydrogen production and CO_2 capture?
5. How is the integration optimised such that the environmental impacts are minimised i.e., energy usage versus operability and any increased emissions during plant upset/non-steady state operation?

D. Process units, scale and experience

1. What process units are proposed for the following?
    a) Sulphur removal
    b) Hydrogen production
    c) CO shift
    d) CO_2 Capture
    e) Hydrogen purification
    f) Oxygen production
    g) Steam and water
    h) Heat and power
2. In which process units is there less operational experience in identical or analogous duty compared with others?
3. What scale have the proposed process units / technologies been used at? What examples are there of plant installations /operations and their associated environmental performance – energy efficiency, minimising continuous/intermittent emissions to air/water/land, waste/water minimisation/recycling/recovery, preventing and minimising consequences of accidents?
4. How has learning from international experience been accounted for?

E. Utilities requirements

1. What are the main utilities requirements for the hydrogen production and CO_2 capture processes?
2. How are utility systems designed and integrated to optimise energy consumption and reduce environmental impacts?
3. Does the hydrogen production process with CO_2 capture require net import or export of electricity? Of Heat?

F. Emissions and waste

1. What continuous or intermittent venting or flaring requirements have been identified? How is this linked with equipment availability and sparing – for example, for CO_2 compression? What availability target is proposed and under what circumstances would hydrogen production continue without CO_2 capture?
2. What are the main solid or liquid waste streams, and how is it proposed these are minimised / recovered / recycled / disposed of?
3. How is process condensate and blow down water segregated, recovered, and reused?
4. What are the main sources of emissions to air and water and how is it proposed these are monitored?
5. Are any chemicals, solvents, catalysts etc. proposed that are potentially harmful to the environment in case of accidental release?
6. What is the fate of any volatile amine degradation products (for example, nitrosamines and nitramines), particularly for any post-combustion CO_2 capture using amines or if captured CO_2 is temporarily vented? Are these limited by water wash on absorber or reflux section above feed in regenerator?

G. Performance metrics

Please provide feedback on the following proposed metrics and any others that are considered relevant to BAT assessment.

1. Process / energy efficiency

Parameter	Description	Units
Feed gas energy conversion	Energy content hydrogen product / energy content feed gas	%
Overall energy conversion	Energy content hydrogen product / overall energy input (including power)	%
Electrical power consumption		MJ / kg H_2
Water consumed by process		kg H_2O / kg H_2
Auxiliary heating duty	Thermal input if not covered in the above	MJ/ kg H_2
Cooling duty	Heat rejected to cooling medium or air	MJ/ kg H_2

2. Emissions

Parameter	Description	Units
CO_2 emissions	Those CO_2 emissions not captured	kg CO_2 / kg H_2
Emissions to air	For component X etc. NOx, CO, etc.	kg X / kg H_2
Emissions to water	For component Y etc.	kg Y / kg H_2
Waste produced	For waste stream. Expressed over lifecycle, annually or per unit of hydrogen produced, as appropriate.	kg

3. Carbon capture performance

Parameter	Description	Units
CO_2 captured from process (pre-combustion)		kg CO_2 / kg H_2
CO_2 captured post-combustion		kg CO_2 / kg H_2
CO_2 captured	Overall pre- and post-combustion	kg CO_2 / kg H_2
CO_2 capture rate	Carbon captured / carbon in feed gas	% kg CO_2 (as carbon) / kg feed gas (as carbon)
CO_2 capture heat duty	Net heat input to CO_2 capture process	MJ / kg CO_2 captured
CO_2 capture power requirement	Net power input to CO_2 capture process	MJ / kg CO_2 captured
CO_2 compression duty	For delivery to pipeline	MJ / kg CO_2 captured

H. Other information

Is there any additional information you propose is considered to support provision of BAT guidance for emerging techniques?

APPENDIX 11: HYDROGEN PRODUCTION WITH CARBON CAPTURE: EMERGING TECHNIQUES

GOV.UK

Guidance

Hydrogen production with carbon capture: emerging techniques

Emerging techniques on how to prevent or minimise the environmental impacts of industrial hydrogen production from methane or refinery fuel gas with carbon capture for storage.

From: **Environment Agency (/government/organisations/environment-agency)**
Published 3 February 2023

Contents

You can produce hydrogen from methane or refinery fuel gas and capture the carbon dioxide (CO_2) which is also produced in this process.

The hydrogen can be:

- used within the installation

- exported as a product

The CO_2 can be:

- transported by pipeline or other means and stored in permanent underground geological storage facilities
- used as a product (not covered in this guidance)

These environmental regulators (referred to as 'the regulators') worked with industry stakeholders to develop a 'review of emerging techniques (https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture)' on which this guidance is based:

- Environment Agency
- Natural Resources Wales
- Northern Ireland Environment Agency (an executive agency of the Department of Agriculture, Environment and Rural Affairs)
- Scottish Environment Protection Agency

Except where existing regulations apply, this guidance on emerging techniques is not a regulatory requirement but identifies best practice to address important environmental issues.

The regulators expect operators to follow this guidance, or to propose an alternative approach to provide the same (or greater) level of protection for the environment.

1. Who this guidance is for

This guidance is for:

- operators when designing their plants and preparing their application for an environmental permit
- regulatory staff when determining environmental permit applications
- any other organisation or members of the public who want to understand how the environmental regulations and standards are being applied

This guidance covers large-scale industrial plants:

- producing hydrogen using methane (for example, from natural gas) or refinery fuel gas
- capturing the CO_2 produced within the process, carbon capture (CC), or using post-combustion carbon capture (PCC) to make it ready for permanent geological storage – this is known as carbon capture and storage or sequestration (CCS)

The guidance covers both new plants and retrofits to existing plants.

It does not cover downstream permanent geological storage or using the captured CO_2.

Large-scale means typically greater than 100 tonnes a day of hydrogen which is around 140MW of hydrogen energy at its lower heating value.

Smaller plant should use this guidance until further guidance is available.

When you apply for an environmental permit for this activity, you must tell your regulator whether you are going to follow this guidance. If not, you must propose an alternative approach which will provide the same or greater level of protection for the environment.

In the UK, these installations are permitted under the:

- Environmental Permitting (England and Wales) Regulations 2016
- Pollution Prevention and Control (Scotland) Regulations 2012
- Pollution Prevention and Control (Industrial Emissions) Regulations (NI) 2013

For environmental permitting purposes, the hydrogen production plant is a Part A (1) 4.2 (a)(i) inorganic chemicals activity.

A CC or PCC plant is a Part A (1) 6.10 (a) carbon capture and storage activity when the CO_2 is being captured from an installation for geological storage.

The existing best available techniques (BAT) reference documents (BREFs) for Large Volume Inorganic Chemicals – Ammonia, Acids and Fertilisers (https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers) and Refining of Mineral Oil and Gas (https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0) do not include hydrogen production with CC, other than as an intermediate product for ammonia production.

The large combustion plant BREF (https://eippcb.jrc.ec.europa.eu/reference/large-combustion-plants-0) identifies carbon capture as an emerging technique but does not address all the potential environmental effects of carbon capture.

Where BAT is not covered in existing BREFs or where all the potential environmental effects are not addressed, the regulator must follow Article 14(6) of the Industrial Emissions Directive (IED) (https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32010L0075#d1e1666-17-1).

This means that your regulator must set permit conditions covering emission limit values (ELVs), together with other permit conditions. These conditions must be based on the regulator's own assessment of emerging techniques using the criteria listed in Annex III of the IED (https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e32-57-1). They should also consult with operators before setting these conditions. The regulators consulted potential technology providers and operators when developing the review of emerging techniques (https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture) on which this guidance is based.

Permits must protect the environment by setting conditions to make sure operators do not breach any environmental quality standards (Article 18 of the IED (https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e1918-17-1)).

Your regulator may grant a temporary derogation (https://www.gov.uk/guidance/best-available-techniques-environmental-permits) of BAT- associated emission levels (BAT AELs) for up to 9 months, on the basis that hydrogen production with carbon capture for permanent storage is testing and using an emerging technique (see Article 15(5) of IED (https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e1802-17-1)). You should discuss this with your regulator if this is likely to apply.

Your regulator will make a decision on the emission limits and other permit conditions that will apply on a case-by-case basis. They will do this based on the elements outlined in this guidance and the most appropriate source of reference.

The review of emerging techniques (https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture) summarises the available evidence to support this guidance. We refer to the relevant sections of the review in this guidance.

You may request advice before applying for your permit (https://www.gov.uk/guidance/get-advice-before-you-apply-for-an-environmental-permit).

For further advice from your regulator, in:

- England, contact the Environment Agency: enquiries@environment-agency.gov.uk
- Scotland, contact the Scottish Environment Protection Agency: ppc@sepa.org.uk

- Wales, contact Natural Resources Wales: enquiries@naturalresourceswales.gov.uk
- Northern Ireland, contact the Northern Ireland Environment Agency: IPRI@daera-ni.gov.uk

2. Technique selection

When choosing hydrogen production and CC plant configuration, you should consider its overall environmental performance, including:

- energy efficiency
- resource efficiency
- CO_2 capture efficiency
- emissions to the environment

These are the hydrogen production methods the regulators considered when producing this guidance:

- steam methane reforming (SMR)
- autothermal reforming (ATR)
- gas heated reforming (GHR)
- partial oxidation (POX)

They also considered combinations of these such as GHR plus ATR and GHR plus SMR.

All of these methods will need to separate out, capture and prepare hydrogen and CO_2 ready for:

- using hydrogen product within the installation
- transporting hydrogen product for use off-site
- transporting CO_2 for permanent geological storage off site

These activities are outside the scope of this guidance.

3. Plant design and operation

3.1 Flexible operation

You must consider whether your hydrogen production plant may need to operate on a flexible basis to balance variations in demand from hydrogen users.

You should consider whether this need for flexibility will affect the design, operation and maintenance of the plant.

You should identify flexible operating scenarios where environmental performance could be affected, or where additional emissions are expected. For example, these could be as a result of rapid changes in capacity, or start-up following enforced shutdown.

You should describe measures you would take to minimise the environmental impact of these scenarios, which could result in, for example:

- reduced CO_2 capture rates
- reduced energy efficiency
- increased emissions to air, venting and flaring
- increased effluent or wastes produced
- increased risk of accidents in non-steady state conditions

3.2 Reliability and availability

You will need to identify equipment and systems that are critical in avoiding emissions. You will need to design, operate and maintain these to make sure they are reliable and available, including providing installed back-up equipment, where necessary.

You should implement a risk-based other than normal operating conditions (OTNOC) management plan, which identifies potential scenarios, mitigation measures, monitoring and periodic assessment.

3.3 Overall CO_2 capture efficiency

You should design plant to maximise the carbon capture efficiency. As a minimum, you should achieve an overall CO_2 capture rate of at least 95%, although this may vary depending on the operation of the plant. You can base this on average performance over an extended period (for example, a year).

Overall carbon capture rate or efficiency is defined as ‘the mass of CO_2 equivalent captured for storage as a percentage of the mass of CO_2 equivalent in all feed gas, including methane or refinery fuel gas (or both) used in combustion plant’.

For clarity, this is the same as ‘the mass of carbon captured as a percentage of the mass of carbon in all feed gas’.

This should be achievable for the hydrogen production and CO_2 capture routes considered for new plant.

You will need to provide justification if you are proposing a design CO_2 capture rate of less than 95%.

You should consider how you would comply with future requirements for increased CO_2 capture efficiency by making your plant decarbonisation ready.

You should plan to allow for space and technical retrofit within the design for additional carbon capture plant. This will allow for the capture of residual emissions of CO_2, for example, from combustion of any hydrogen purification residual gas.

This is to future-proof the plant so you can comply with any future requirements for carbon capture ready for emissions of CO_2 and the likely changes to CO_2 capture efficiency required.

You should note that any carbon-containing compounds as allowed by the hydrogen product specification will be emitted to the environment in downstream uses, such as combustion. You should aim to minimise these where feasible.

For more detail, see the review of emerging techniques (https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture):

- section 5.7 Carbon capture efficiency
- section 6.3, Table 22: Carbon capture key performance parameters

3.4 Process CO_2 capture from hydrogen product

Technology for CO_2 capture from hydrogen product will typically be through absorption in a circulating solvent, with regeneration of the solvent through reducing pressure and heating to liberate CO_2.

You should select the solvent, process design and operating conditions that maximise energy efficiency, capture performance, and minimise the waste and effluent treatment required. Where you have considered various options, you should provide the reasoning behind this to demonstrate that your chosen option uses overall BAT.

This could include, for example:

- maximising absorption for CO_2 capture
- optimising solvent regeneration to provide CO_2 at high pressure, but avoiding excessive degradation of solvent
- maximising heat exchange between lean and rich solvent streams

- minimising solvent carryover to minimise the need for downstream removal
- minimising wastes and effluent streams, while removing contaminant build-up in solvent

For more detail, see the review of emerging techniques (https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture), section 5.4.

3.5 CO_2 capture for steam methane reforming

In SMR, heat for the reformer reaction is provided by external combustion in a furnace.

The fuel gas can be either:

- methane (usually from natural gas feed)
- refinery fuel gas
- hydrogen product
- a combination of these

All require post combustion capture to remove the CO_2 produced from the flue gas, except where pure hydrogen product is used as the fuel. Following consultation with industry, the regulators expect that more than 95% of CO_2 can be removed from the reformer flue gases.

The plant could be designed in such a way that no post combustion capture is needed if both of these apply:

- hydrogen is used as the fuel gas for the reformer
- there is in-process CO_2 removal prior to hydrogen purification

You will need to justify the best overall approach, considering all environmental impacts.

If post-combustion CO_2 capture is needed, you should use the guidance post-combustion carbon dioxide capture: emerging techniques (https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat) (referred to as PCC guidance).

You should take account of any differences between the flue gases considered in the PCC guidance and the flue gases from the SMR reformer furnace.

These differences could be, for example, oxygen and nitrogen content, potential for formation of nitrogen oxides (NO_x) and impact of requirement for flexible operation.

When optimising for environmental performance, you should consider:

- selecting appropriate solvents
- emissions to air of solvent and associated degradation products
- energy requirements
- effluents and wastes
- cooling requirements
- pump and fan noise
- flue gas pre-treatment
- treated flue gas dispersion

For more detail, see the review of emerging techniques (https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture), sections 5.5 and 5.6.

3.6 CO_2 capture from residual gas from hydrogen purification

You should consider how to capture CO_2 produced by the combustion of residual gas, which results when hydrogen is purified.

You should aim to remove this CO_2 to maximise the overall carbon capture efficiency and to make sure you achieve at least 95%.

The residual gas may contain methane, carbon monoxide (CO) and CO_2 as well as hydrogen, nitrogen and argon. This is normally used as a fuel gas and any carbon containing compounds will be converted to CO_2.

The amount of carbon-containing compounds depends on the efficiency of conversion and removal before the hydrogen purification stage.

For more detail, see the review of emerging techniques (https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture), section 5.9.

3.7 Energy efficiency, process efficiency, cooling

You should choose your hydrogen production process and design your plant to maximise:

- energy efficiency (minimise the energy needed to produce each tonne of hydrogen)
- process efficiency (minimise the raw materials, such as methane and water, needed to produce each tonne of hydrogen)

To decide on BAT, you will have to balance how you achieve these efficiencies in order to optimise the environmental and economic requirements.

You must explain how you have done this and what your considerations were.

This should take into account all of the chemical and physical processes within the installation boundary needed to produce hydrogen and capture carbon.

Main energy users will include:

- air separation unit (ASU) – for oxygen supply to ATR and POX
- hydrogen compressors
- CO_2 compressors
- hydrogen and CO_2 purification
- solvent recovery system
- pumping or fan systems

You should consider:

- electrical power needs and whether you will import or generate on site
- high pressure steam need and availability
- maximising any residual waste heat recovery
- cooling needs
- cooling type and medium

You should also consider heat integration optimisation, for example, heat recovery at:

- higher temperatures from compression systems including the ASU, CO_2 and hydrogen compression for power generation or drives
- medium temperatures for solvent recovery
- lower temperatures for boiler feed pre-heat

See also section 3.9 Water supply and use.

You should reference the BREF documents:

- Industrial Cooling Systems (https://eippcb.jrc.ec.europa.eu/reference/industrial-cooling-systems)
- Energy Efficiency (https://eippcb.jrc.ec.europa.eu/reference/energy-efficiency)

For further details, see the review of emerging techniques (https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture):

- section 5.10
- section 6.1 Table 20

3.8 Oxygen production

Oxygen is required for the ATR and POX processes. It is usually produced by an ASU, which is a relatively large energy user.

You must consider heat recovery from the heat generated by the air compression system and whether you can use it within the rest of the hydrogen production process to maximise energy efficiency. We expect you to explore all opportunities for waste heat recovery as the ASU will be considered part of the installation.

You should take the following into account when designing the oxygen production plant and optimise to show you are using BAT:

- overall energy consumption depends on the design of the ASU and its air compressor
- energy required will be a balance between oxygen purity, oxygen pressure needed to supply the hydrogen production process and energy needed to purify the hydrogen
- higher oxygen purity will increase the energy required for oxygen production, but reduce the amount needed for hydrogen purification to remove residual argon and nitrogen
- co-production of argon and nitrogen can be used for export or on site
- heat energy needed to dry and purify the compressed air
- options to increase the compressor exit temperature to improve options for heat recovery should be explored, balanced with compressor design and higher power requirement.
- safe and reliable operation of both the ASU and hydrogen production plant where heat integration is used
- high availability of oxygen supply and backup supply or liquid storage is important to avoid potential environmental impacts of emergency or frequent shutdown and start-up of the plant

For further details, see the review of emerging techniques (https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture), section 5.12.

3.9 Water supply and use

Water supply and its efficient use is an important aspect of BAT in hydrogen production plant.

The quality of the water supply will determine the pre-treatment needed before it can be used as a:

- raw material in hydrogen production
- heat transfer medium
- cooling medium

Water is consumed in the process as part of the hydrogen product.

Your choice of hydrogen production method will determine the ratio of hydrogen product that comes from water compared with that which comes from methane, or refinery fuel gas, or both.

For further details see Water consumption (process) in Table 20 of the review of emerging techniques (https://www.gov.uk/government/publications/review-of-emerging-techniques-for-hydrogen-production-from-methane-and-refinery-fuel-gas-with-carbon-capture).

You should:

- minimise the amount of water you use
- segregate, treat and reuse water where possible
- choose a cooling method that takes account of the temperature impact on process performance, energy efficiency and environmental impact on the receiving medium

For refineries, you should also comply with BAT conclusion 11 emissions to water from the BAT conclusions (BATC) for refining of mineral oil and gas (https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL_2014_307_R_0009).

3.10 Water treatment

Water and steam are used in the process.

Water is condensed both from steam systems and from process cooling. In most cases, this water can be reused without being treated. However, some water will need to be removed to avoid the build-up of contaminants. You will need to treat it in an effluent treatment system before releasing it into the environment.

You should decide how much water to treat and how to treat it before it is:

- reused
- released to surface water or sewage undertaker
- disposed of

You should identify how much contaminant, such as methanol and ammonia, needs to be removed and design the treatment process accordingly.

You should identify any emissions to air or wastes that may result from the water treatment process, for example, emission of CO_2 from deaeration of boiler feed water.

You should use the following references to choose the most appropriate treatments:

- BREF and BATC for common waste water and waste gas treatment/management systems in the chemical sector (https://eippcb.jrc.ec.europa.eu/reference/common-waste-water-and-waste-gas-treatmentmanagement-systems-chemical-sector-0)
- BREF and BATC for refining of mineral oil and gas (https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0)

For discharges to water, you should refer to the guidance Surface water pollution: risk assessment for your environmental permit (https://www.gov.uk/guidance/surface-water-pollution-risk-assessment-for-your-environmental-permit).

For further details on water treatment for re-use, see the emerging techniques review, section 5.13.

3.11 Feed gas quality and treatment

Your choice of supply of methane-containing feed gas will determine the type of gas treatment processes you will need prior to the main conversion reactions., It will also determine whether you will need to remove inert gases at the hydrogen purification stage.

If you use refinery fuel gas as your feed gas supply, where possible, you should remove contaminants such as sulphur and mercury in existing upstream refinery processes, taking account of BAT across the refinery installation.

You will need to take account of the possible range of gas composition so that you can design your processes to minimise the overall environmental impact, including substances such as:

- sulphur (S), typically as H_2S
- nitrogen (N_2)
- CO_2
- mercury
- other hydrocarbons

You will need to design your gas treatment and downstream processes in order to:

- minimise solid wastes (for example, catalyst) for recycling or disposal
- minimise sulphur dioxide (SO_2) emissions to air where feed gas is combusted
- maximise overall process reaction and energy efficiency
- minimise emissions to air associated with the removal of nitrogen or other inerts

You should consider removing sulphur compounds by hydrogenation and using catalyst adsorbent to avoid SO_2 emissions from combustion and catalyst poisoning.

You should consider removing other hydrocarbons by pre-reforming to avoid carbon deposition on catalysts.

You should consider the impact a pre-reforming step will have on the downstream reforming stage for an SMR. You may be able to optimise the energy efficiency and minimise NO_x emissions to air due to reduced gas fired reformer furnace duty. You will need to consider the impact on steam balance for the plant.

You should remove mercury to avoid catalyst poisoning and other downstream contamination.

Any CO_2 in the feed gas will be removed along with the CO_2 produced in the process. You should include this in the overall CO_2 balance and capture efficiency monitoring and reporting.

3.12 Reforming and CO shift

Hydrogen is produced in the reforming and CO shift stages of the plant.

You should convert methane to hydrogen, CO and CO_2 in the reforming stage, while minimising unreacted methane.

You should optimise CO conversion to CO_2 considering the overall CO_2 capture requirement and the impact on downstream processing stages to meet the hydrogen product specification.

3.13. Reforming

You should select, design and operate the reformer reaction in order to:

- reduce the risk of carbon deposition on catalyst, which would result in reduced reaction efficiency
- minimise catalyst change frequency and the need for recycling or waste disposal

If you choose ATR or POX technologies, carbon formation may be more likely due to the reducing atmosphere. You should choose operating parameters to minimise this risk.

3.14 CO shift

You should select, design and operate CO shift reaction in order to:

- maximise energy efficiency through, for example, heat integration with the overall hydrogen production and CO_2 capture processes
- minimise the duration of start-up operations and associated emissions to air from flaring
- minimise the production of wastes for recycling or disposal

You should consider a single step CO shift process rather than a more conventional high temperature or low temperature shift process, with isothermal conditions achieved through reactor cooling with recovery of heat.

By using this option, it may allow you to:

- increase overall heat integration and efficient use of recovered heat, as long as sufficient conversion of CO to CO_2 is achieved
- avoid using chromium catalyst needed for high temperature shift, therefore minimising hazardous waste
- reduce the potential for catalyst damage, methanation reactions, and Fischer-Tropsch reactions
- reduce the potential for the production of methanol which would condense out with water downstream and need to be treated by effluent

treatment

- consider the cost and environmental benefits of an isothermal reactor against a more complex multi-tube boiling water-cooled reactor

Refer to BREF for large volume inorganic chemicals – ammonia, acids and fertilisers (https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers) – section 2.4.14 Isothermal Shift Conversion.

3.15 Catalyst selection

When you choose which catalysts to use, you should consider the overall environmental performance, including, for example:

- any required pre-treatment to avoid poisoning, to minimise waste and associated treatment
- preventing any dust emissions, where applicable
- the ability to recover or recycle the solids or metals from the spent catalyst waste
- handling spent catalyst for environmentally safe recovery, recycling or disposal

3.16 Hydrogen product

You will need to purify and compress hydrogen so that it is fit for purpose after it is separated from the CO_2 in the CO_2 capture stage.

You should take account of hydrogen purification requirements. These will depend on:

- the hydrogen product quality specification
- impurities in the hydrogen following reforming, CO shift and CO_2 capture steps

The impurities may include:

- CO, which is not converted to CO_2 in the reforming or CO shift sections
- CO_2, which is not removed in the CO_2 capture section
- methane, which is not converted to CO in the reforming section
- nitrogen and argon – inert gases present in feed gas or oxygen supply
- water – the hydrogen is saturated with water following CO_2 capture

You should consider pressure swing adsorption (PSA) to remove impurities from the hydrogen. Treating residual gas containing the impurities is considered in section 3.6 CO_2 capture from residual gas from hydrogen purification.

You should consider whether methanation to convert CO into methane is appropriate, depending on the specification of hydrogen, to make sure hydrogen is fit for purpose.

You should consider the impact on overall energy efficiency and the need for further treatment of hydrogen purification off-gas streams.

You should design the overall process to minimise the power required for compression to achieve the pressure required by the user. See section 3.7 energy efficiency, process efficiency, cooling.

3.17 CO_2 product

You should design the process to meet the required CO_2 quality specification, temperature and pressure as required for transport to permanent geological storage.

You should design the overall process to minimise the power required for compression to achieve the pressure required by the user. You should maximise recovery of waste heat from compression. See section 3.7 energy efficiency, process efficiency, cooling.

4. Emissions to air

You should eliminate, minimise or reduce any emissions to air that could cause pollution.

You should make sure that your process emissions can comply with all ELVs which are required under the relevant BATC.

You should carry out a risk assessment, including detailed air quality modelling, to assess the impact of these emissions.

4.1 Combustion processes

You should maximise energy efficiency and heat integration so you minimise the need for combustion processes, resultant CO_2 and other combustion products.

You should maximise the capture of CO_2 from combustion processes, taking account of the overall carbon capture requirement.

If you decide that carbon capture from a combustion process is not appropriate, you must justify your decision based on BAT. You must identify and minimise the continuous and periodic emissions of combustion products to air.

You should consider NO_x abatement techniques where the combustion of hydrogen-rich gas with the potential for higher flame temperatures will increase thermal NO_x formation, including:

- burner design
- flue gas recirculation
- heat exchange with fuel or air

You should consider whether abatement of any of these emissions is required to comply with relevant BAT AELs or local air quality standards, for example, for NO_x. Where relevant, you should consider the following abatement techniques:

- selective catalytic reduction (SCR)
- selective non-catalytic reduction (SNCR)

You should consider:

- the overall impact of using residual gas from the hydrogen purification process as a supplementary fuel for fired equipment to balance overall heat requirements, while considering the impact of the additional emissions of combustion products to air
- for SMR, the requirement for post-combustion carbon capture for the reformer furnace emissions to air and any pre-treatment of combustion gases needed see the PCC guidance (https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat)
- for ATR, whether the relatively smaller additional heat need can be supplied by combustion of hydrogen-rich residual gas or combustion of hydrogen product
- for POX, the process is usually energy-balanced or produces excess heat and so combustion processes may not be needed
- the impact on emissions to air due to variability in fuel gas composition or any need to switch between fuel gas sources, for example, at start-up when residual PSA gas for fuel is not available and some feed gas may need to be combusted

You could consider using excess oxygen, where available, to support oxy-combustion, in order to remove the source of nitrogen and therefore limit thermal NO_x formation.

Fuel NO_x may form from nitrogen in the residual gas from the PSA. There is limited experience of using oxygen, especially for hydrogen-rich gases and any such proposal would need to be fully justified with supporting data.

You should design combustion processes to comply with required emissions limit values (ELVs) from the existing sources of statutorily applicable emission limits and BAT AELs, including the following:

- Medium Combustion Plant Directive (https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32015L2193)
- Industrial Emissions Directive Chapter III Annex V ELVs (https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN#d1e32-59-1)
- BAT AELs identified in the Large combustion plant BREF (https://eippcb.jrc.ec.europa.eu/reference/large-combustion-plants-0) and BATC
- Refining of Mineral Oil and Gas (https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0)
- Large Volume Inorganic Chemicals – Ammonia, Acids and Fertilisers (https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers)
- Common Waste Water and Waste Gas Treatment/Management Systems in the Chemical Sector (https://eippcb.jrc.ec.europa.eu/reference/common-waste-water-and-waste-gas-treatmentmanagement-systems-chemical-sector-0)

You should consider the:

- type of combustion equipment
- fuels proposed to be combusted
- net rated thermal inputs
- BAT for control of emissions
- conclusions of an environmental risk assessment, considering the dispersion of pollutants into air and the sensitivity of the relevant receptors

4.2 Post combustion capture plant

Refer to the PCC guidance (https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat) – section 3.3 Features to control and minimise atmospheric and other emissions.

4.3 Flaring and venting

You must design and operate your plant to minimise the need for continuous or intermittent flaring or venting of gases, whether for operational or safety reasons, including:

- methane or refinery fuel gas
- hydrogen
- CO_2

This should include:

- flaring rather than venting, where emissions cannot be eliminated and where practicable, to minimise emissions of higher global warming potential gases such as methane and hydrogen
- plant design to maximise equipment availability and reliability (see section 3.2 Reliability and availability)
- avoiding routine flaring for waste gas destruction
- managing production of off-gas and balance against requirements for fuel gas using advanced process control, for example
- using procedures to define operations, including start-up and shutdown, maintenance work and cleaning
- using commissioning and handover procedures to ensure that the plant is installed in line with the design requirements
- using return-to-service procedures to ensure that the plant is recommissioned and handed over in line with the operational requirements
- designing flaring devices to enable smokeless and reliable operations, and to ensure an efficient combustion of excess gases when flaring under other than normal operations
- monitoring and reporting of gas sent to flaring and associated parameters of combustion

You must minimise emissions under start-up, shutdown, and abnormal operations. This can be achieved by:

- using a flare gas recovery system with adequate capacity
- routing gas that would be flared to alternative users
- using high integrity relief valves
- other measures to limit flaring to abnormal operation

If your activity is part of a refineries installation, you should refer to BAT conclusions 55 and 56 in BATC for the Refining of Mineral Oil and Gas (https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL_2014_307_R_0009).

You should quantify and assess harm from other routine venting and purging requirements, identifying any pollutants that are expected to be present, including, for example:

- CO_2

- hydrogen
- CO
- methane
- ammonia vapour
- methanol vapour

Requirements for continuous venting during normal operations may include, for example:

- water vapour from CO_2 dehydration systems using circulating tri-ethylene glycol
- deaeration of steam condensate or boiler feed waters
- gases from processing waste water streams
- purge of tanks, vent or flare headers

Requirements for intermittent venting may include, for example:

- CO_2 vented in abnormal conditions, such as when the downstream transportation and storage system is not available, or if the CO_2 does not meet the export specification
- venting needed as part of purging equipment for maintenance activities

5. Emissions to water

You must identify and eliminate, minimise, recycle or treat any emissions to water that could cause pollution.

You should carry out a risk assessment, including detailed modelling, where appropriate, to assess the impact of these emissions.

For discharges to water, you should refer to the guidance Surface water pollution: risk assessment for your environmental permit (https://www.gov.uk/guidance/surface-water-pollution-risk-assessment-for-your-environmental-permit).

5.1 Effluent treatment discharges

You should identify continuous and periodic effluent streams from the process and determine whether effluent treatment is required. These streams may include process condensate containing contaminants, which may need treatment before discharge, for example:

- methanol
- ammonia
- CO_2

- amines
- degradation products

You should treat water for reuse as far as possible. See section 3.10 Water treatment.

You should refer to the appropriate BREF and BATC (where available) if the installation is considered to be part of a refinery or a chemicals installation:

- Refining of Mineral Oil and Gas (https://eippcb.jrc.ec.europa.eu/reference/refining-mineral-oil-and-gas-0)
- Common Waste Gas Management and Treatment Systems in the Chemical Sector (https://eippcb.jrc.ec.europa.eu/reference/common-waste-gas-treatment-chemical-sector)
- Large Volume Inorganic Chemicals – Ammonia, Acids and Fertilisers (https://eippcb.jrc.ec.europa.eu/reference/large-volume-inorganic-chemicals-ammonia-acids-and-fertilisers)

6. Waste

You must eliminate or minimise wastes and treat, where appropriate.

You should consider how to deal with the following wastes that may be generated.

6.1 Liquid wastes

Liquid wastes such as:

- demineralised water production reject stream
- amine solvent – for example, from bleed or feed replacement
- dehydration solvent – for example, in case of tri-ethylene glycol dehydration
- amine reclaimer residue

6.2 Solid wastes

Solid wastes such as:

- depleted catalyst material – hydrogenation, reforming, CO shift
- spent adsorbent materials – gas treatment, dehydration, hydrogen purification
- solids from amine filtration
- soot (POX process)

7. Monitoring

The main purpose of monitoring is to demonstrate compliance with the permit and show that emissions from the process are not causing harm to the environment.

You must also carry out monitoring to show that resources are being used efficiently. This includes:

- energy and resource efficiency
- carbon capture efficiency
- verifying that the CO_2 product is suitable for safe transport and storage
- hydrogen product quality
- verifying (when applicable) compliance with low carbon hydrogen standards

Your permit application should include a monitoring plan for both a commissioning phase and routine operation.

During the commissioning phase, you will need to assess monitoring results and optimise the operation of the process. You will need to report on your commissioning phase monitoring results, your assessment of them and any changes you want to make to the operation.

It’s likely you will need to do more extensive monitoring during the commissioning phase than during routine operation. As these production techniques for hydrogen with CCS are emerging techniques, you will need to develop monitoring methods and standards. You should include proposals for this in your permit application.

Complying with ELVs in your permit will provide the necessary protection for the environment, by monitoring emissions at authorised release points. You must also show that you are managing the process to prevent (or minimise) the formation of solvent degradation products.

Where degradation products are formed (and may be released), you must reduce these and any solvent emissions to the appropriate level. This process control monitoring will also be part of the permit conditions.

7.1 Monitoring point source emissions to air

You should provide a monitoring plan for monitoring emissions to air, based on expected pollutants such as:

- ammonia
- amine compounds

- SO_2
- NO_x
- CO
- methane
- hydrogen

You should do this using appropriate methods and measuring techniques.

Emissions of methane and hydrogen should be eliminated or minimised due to their global warming potential.

Your monitoring should consider, for example:

- NO_x and CO emissions from combustion
- SO_2 emissions from combustion where the fuel source contains sulphur
- ammonia emissions where SCR or SNCR is used
- amine or amine degradation products and other volatile solvent emissions, where relevant
- methane and hydrogen ‘slip’ from any combustion processes
- any other sources of methane or hydrogen emissions

For combustion plant, your monitoring plan should demonstrate compliance with the applicable emission limits described in section 4.1 Combustion processes.

Where you are using post-combustion CO_2 capture, for example, using amine solvent, your plan should include monitoring relevant emissions such as:

- ammonia
- volatile components of the capture solvent
- likely degradation products such as nitrosamines and nitramines

Specific pollutants arising from post-combustion capture may be monitored by continuous emissions monitors, if they are available, or by periodic extractive sampling. Where aerosol formation is expected, the sampling must be isokinetic.

7.2 Monitoring emissions to water

You must monitor emissions to water based on expected impurities (for example, ammonia, amine compounds, methanol, CO_2) using appropriate methods and measuring techniques.

You should use monitoring standards for discharges to water following:

- BATC for common waste water and waste gas treatment/management system in the chemical sector (https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1579188127132&uri=CELEX%3A32016D0902)
- BATC for the refining of mineral oil and gas (https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ%3AJOL_2014_307_R_0009)

7.3 Monitoring standards

The person who carries out your monitoring must be competent and work to recognised standards such as the Environment Agency's monitoring certification scheme (MCERTS) (https://www.gov.uk/government/collections/monitoring-emissions-to-air-land-and-water-mcerts).

MCERTS sets the monitoring standards you should meet. The Environment Agency recommends that you use the MCERTS scheme, where applicable. You can use another certified monitoring standard, but you must provide evidence that it is equivalent to the MCERTS standards.

There are no prescriptive BAT requirements for how to carry out monitoring. Monitoring methods need to be flexible to meet specific site or operational conditions.

You must use a laboratory accredited by the United Kingdom Accreditation Service (UKAS) (https://www.ukas.com/) to carry out analysis for your monitoring.

You should also refer to the JRC Reference Report on Monitoring for IED Installations (https://eippcb.jrc.ec.europa.eu/reference/monitoring-emissions-air-and-water-ied-installations-0).

7.4 Monitoring CO_2 capture performance

You should clearly identify how you will monitor the CO_2 capture performance of the plant.

The regulators expect you to monitor CO_2 capture performance according to standards that are recognised under the UK ETS. Measurements required to monitor CO_2 emissions to atmosphere may, for example, include directly measuring the flow and composition of fuel gas to combustion systems.

This, together with measuring the following, will allow monitoring of the CO_2 capture rate and CO_2 quality (considering any impurities that could impact downstream systems):

- flow and composition of feed gas
- hydrogen product (including methane content where applicable)
- CO_2 product streams

You will need to include:

- CO_2 equivalent mass balance
- CO_2 equivalent in feed gas
- total capture efficiency (CO_2 equivalent captured as a mass percentage of CO_2 equivalent in feed gas)
- CO_2 equivalent released to the environment
- CO_2 quality

7.5 Monitoring process performance

You should identify the main requirements for monitoring process operations where these ultimately impact on environmental performance, including, for example, for the CO_2 capture system:

- amine system performance, including monitoring of amine solvent quality such as amine concentration
- pH and presence of degradation or corrosion products
- amine temperatures
- amine and wash water circulation rates
- rich and lean amine CO_2 loading
- stripper reboiler steam rates

You should monitor energy efficiency in the hydrogen production and CO_2 capture processes by measuring feed and product gas flows and electrical power consumption to calculate overall energy consumption.

You should monitor the quality of the hydrogen product to ensure it is fit for purpose.

Requirements for process performance monitoring, either online or offline, will also be a condition of the permit.

8. Unplanned emissions and accidents

You should propose a leak detection and repair (LDAR) programme that is appropriate for the fluids and their composition. This should use industry best practice to manage releases, including from joints, flanges, seals and glands.

You should include how you will use LDAR to eliminate or reduce fugitive emissions of methane and hydrogen due to their global warming potential.

Your hazard assessment and mitigation for the plant must consider the risks of accidental releases to the environment. This should also consider the actual composition of the liquids, gases and vapours that could be released from the plant after an extended period of operation.

9. Noise and odour

You need to consider sources that have high potential for noise and vibration. In particular, CO_2 and hydrogen compression, pumping and fan noise could be significant additional sources.

Once you've identified the main sources and transmission pathways, you should consider using common noise and vibration abatement techniques and mitigation at source, wherever possible. For example:

- embankments to screen the source of noise
- enclosure of noisy plant or components in sound-absorbing structures
- anti-vibration supports and interconnections for equipment
- orientation and location of noise-emitting machinery
- changing the frequency of the sound

Please refer to Noise and vibration management: environmental permits (https://www.gov.uk/government/publications/noise-and-vibration-management-environmental-permits).

Handling, storing and using some amines may result in odour emissions, so you should always use best practice containment methods. Where there is increased risk that odour from activities will cause pollution beyond the site boundary, you will need to send an odour management plan with your permit application.

In England, Wales and Northern Ireland please refer to Environmental permitting: H4 odour management (https://www.gov.uk/government/publications/environmental-permitting-h4-odour-management). In Scotland refer to Odour guidance 2010 (https://www.sepa.org.uk/media/154129/odour_guidance.pdf).

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