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Vysus Group

Feasibility study on repurpose of oil and gas infrastructure for offshore hydrogen generation

Report prepared for SOWEC

Report Information

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Executive summary

This report has been prepared by Vysus Group for Crown Estate Scotland and the Scottish Offshore Wind Energy Council (SOWEC).

The report documents the findings of a feasibility study undertaken by Vysus Group to identify opportunities and risks associated with the repurpose of oil and gas infrastructure for offshore hydrogen production.

The assignment was conducted as a desk study over a period of 12 weeks, January 2021 to end March 2021 and involved a review of publicly available information and in-house data sources together with consultation with a range of stakeholders.

It is expected that this report shall be of interest to a broad range of organisations involved in the generation of hydrogen offshore. Organisations will include developers, operators, EPC contractors, equipment manufacturers, specialist contractors, policy makers, regulators and other key stakeholders. The report is also expected to be of interest to those organisations considering asset life extension, net zero modifications and decommissioning of offshore assets.

Study areas covered by the report are:

- An overview of the development and consenting processes for commercial scale offshore green and blue hydrogen production in the UK;
- An overview of electrolyser technologies, with identification of those most suited for offshore hydrogen production;
- An overview of the fundamental approach to making best use of existing infrastructure including transmission lines, and platforms for generation and transmission;
- An overview of the cost estimation for key enabling hydrogen supply chain capability and infrastructure including existing offshore oil and gas infrastructure, electrolyser supply, port and quayside infrastructure, reinforced quayside areas (with services), operation and maintenance marine and quayside operations;
- A cost comparison, and benefit analysis of onshore vs offshore hydrogen production;
- Identification and assessment of generic risks and mitigations for a project developer;
- Identification of generic opportunities for a project developer;
- Capacity of the above to deliver a strong pipeline of hydrogen projects from the late 2020s to 2050;
- Consideration of desired UK content targets;
- Consideration of industry demand in likely hydrogen clusters; and
- Prioritised recommendations for further work, consistent with the SOWEC energy transition vision.

Conclusions and recommendations of the report are presented overleaf.

Conclusions

The conclusions presented here are drawn from key points addressed in the discussion of candidate infrastructure; technology; economics, capacity and demand; adequacy of regulatory, QHSE and associated management frameworks; UK content targets; and industry demand.

Importantly, the study does not attempt to draw conclusions about broader points concerning hydrogen production or attempt to identify specific infrastructure as candidates for repurposing.

Candidate infrastructure

Existing offshore infrastructure identified as having the potential to be re-purposed for the production of offshore hydrogen may be categorised, as:

- In service and end of life floating and fixed production installations, with larger fixed installations located in the Northern North Sea (NNS) and Central North Sea (CNS);
- End of life pipelines, with candidates for export or storage of hydrogen product, disposal of CO_2 and the import of natural gas feedstock for Steam Methane Reforming (SMR) operations located in the NNS and CNS;
- Subsurface storage facilities already identified for Carbon Capture, Utilisation and Storage (CCUS) service which will be required to capture the Carbon Dioxide (CO_2) by-product of SMR hydrogen production; and
- Subsea infrastructure such as well heads, manifolds, mattresses and other subsea equipment. It is noted, however, that these are unlikely to have a major impact on the overall cost of a hydrogen generation project.

Brent infrastructure located in the NNS and Markham field in the CNS provides ideal donor sites for consideration, as these sites are located in close proximity to connecting pipelines and Offshore Wind Farm (OWF) developments.

A converted bulk carrier is ideally suited to provide a platform to host hydrogen production equipment from constrained offshore renewable resources found to the north of the Scottish mainland.

Supply chain infrastructure necessary for the repurposing of candidate oil and gas installations has been an established part of the Scottish oil and gas economy for many years. This infrastructure is well placed to support repurposing towards a hydrogen economy.

- Many ports routinely supply the offshore oil and gas industry and have already received decommissioned infrastructure removed from offshore fields with local supply chains processing the material.
- Scottish ports are located in relative proximity to North Sea oil and gas infrastructure; they demonstrate the physical means, organisational capabilities, and experience to support a repurposing effort which will require a multidisciplinary approach to repurposing.
- A multidisciplinary approach is expected to transcend engineering services, project management, marine operations, supply base logistics decommissioning and waste management.

Whilst there are real opportunities to re-purpose redundant pipelines which are located in relative proximity to donor infrastructure and OWFs, this report highlights a number of challenges that must be addressed by policy makers, industry and regulators if the infrastructure is to become available for repurposing:

- Economic uncertainties associated with the condition of redundant pipelines;
- Not identifying areas of high corrosion and/or particularly thin walls and overestimating the integrity of an existing pipeline for its new duty of transporting hydrogen;
- Integrity issues resulting from reverse reeling processes;
- Differences in physical and chemical properties between hydrogen and natural gas (methane). In particular, the suitability of existing equipment for high hydrogen content with regard to stress cracking etc. (The suitability of carbon steel pipelines for transporting hydrogen gas or mixtures has been identified as being dependent on a number of embrittlement and degradation mechanisms, which are attributed to hydrogen. The recommended pipeline material grades for hydrogen service are API X42 and X52. Grades above X52 are more likely to be severely affected by hydrogen embrittlement); and
- Pipeline availability and potential conflict with decommissioning plans.

Technology

This study into the application of SMR, electrolysis and gas to graphene technologies in theoretical repurposing scenarios concluded:

- SMR and electrolysis are both commercially viable, but – in the mid-term - electrolysis will be the preferred process for offshore hydrogen production;
- Whilst SMR currently enjoys a cost advantage, it is expected that electrolyser costs will reduce significantly as the market develops;
- Electrolysis does not carry the CO_2/GHG burden of SMR;
- One disadvantage associated with electrolysis is the lack of an electrolyser manufacturer in Scotland to take advantage of the expected growth in commercial demand for the equipment. Addressing this deficit should be regarded by policy makers as a priority item to stimulate the market and encourage growth of an indigenous industry;
- Onshore scalability of hydrogen production via SMR far beyond what can be achieved offshore suggests that offshore SMR is a technology for tactical purposes such as a production asset net zero emissions enabler. To realise potential as a net zero enabler, policy makers, regulators and industry need to consider the linkage between offshore SMR technology and the road to a low carbon future;
- Onshore SMR is likely to play an important role as an enabler of hydrogen market growth and development;
- Hydrogen production via the gas to graphene production process exhibits significant potential as a means of utilising the methane that would have otherwise been flared. The graphene production process is also expected to reduce costs associated with CO_2 emissions and flaring consent from a retrofitted oil and gas production asset. In common with SMR deployed offshore, gas to graphene production should be considered in the context of a net zero operating strategy to realise the full potential associated with a reduction in methane emissions and an expected increase in carbon tax.

Economics, capacity and demand

The Scottish Government Hydrogen Policy Statement has identified three scenarios to develop a hydrogen economy over the period 2025, 2035, and 2045 where between 70,000 and 300,000 jobs will be protected or created with GVA impacts of between £5 billion and £25 billion by 2045.

- Regional Growth;

- Scottish Hydrogen Economy;
- European Outreach (exporter of hydrogen).

During this period the Scottish Government expects to increase production from small scale operations with circa 200 MW per unit production capacity for green hydrogen to over 25 GW total by 2045. The majority of the green production is expected to be offshore at large scale.

Depending on pricing of hydrogen, carbon pricing and cost of entry to the market, these figures demonstrate a significant potential market opportunity for repurposed offshore infrastructure to host equipment.

The results of cost comparison analysis between electrolysis and SMR suggest that at this point in time, SMR is the more attractive option for hydrogen generation. However, where these technologies are compared over a longer time period, electrolysis emerges as the more favourable option from an economic point of view.

When considered as part of a re-purposing scenario, a number of economic issues must be overcome if an offshore re-purposing solution is to be achievable:

- The costs of addressing technical and safety challenges represent significant hurdles which need to be addressed before cost reductions can be achieved;
- Costs associated with a complete re-build of an offshore platform to create space and achieve structural reinforcement to accommodate new equipment will vary significantly, depending on individual circumstances;
- Onshore new build facilities are expected to offer significant cost savings over offshore solutions due to the proximity of generating plant to end user, and beyond. Other savings are expected to reflect the lower costs associated with logistics, labour rates and HSE risk management.

Where the cost of a re-purposed offshore installation is expected to exceed the cost of an equivalent new build or where the economics of a re-purposed offshore installation are not expected to compete with the economics of an onshore hydrogen production facility, proponents of repurposing existing infrastructure are advised to develop an economic model that permits a fuller project comparison. Such a model should be based on accounting sound practices, taking account of defined project boundaries, defined project life cycle systems and activities, direct and indirect costs, calculation methodology, carbon taxes and other environmental taxes and other influencing factors. The model should be developed as a joint industry initiative, and refined over time to reflect any cost savings attributable to the maturation of technological solutions, project management efficiencies and / or increase in carbon tax.

Regulatory framework

The findings of this study suggest that the UK benefits from a well-developed regulatory framework, experienced in the regulation of onshore and offshore sites with the potential for a major accident.

Knowledge of the existing regimes suggests that the regulations, codes and standards can readily be applied to assets repurposed to host offshore hydrogen generating equipment; e.g. DCR [1] regulations intended for use in the offshore oil and gas industry have found application in the management of safety in the design of offshore substations.

[1] The Offshore Installation and Wells (Design and Construction, etc) Regulations 1996

These findings are in contrast to feedback received from many consultees, which suggested there are major gaps in the regulatory framework which are perceived as a significant barrier to further industrial development.

The gap between perception of stakeholders and the extent to which the regulatory regime addresses all hazards and risk factors associated with a repurposing scenario is not known. There is therefore a requirement to understand the similarities, differences, knowledge gaps and areas where knowledge transfer is possible between systems such as oil and gas safety cases, construction CDM [2] arrangements, marine International Safety Management (ISM) codes and onshore Control of Major Accident Hazards (COMAH) regimes.

QHSE and asset management

Stakeholders consulted as part of this project identified the current offshore and onshore workforce as being ideally suited to support the repurposing of existing offshore infrastructure for hydrogen production. However, stakeholders raised concern that skills gaps existed that could affect the ability of an individual to adapt to new opportunities where knowledge and experience of hydrogen safety and technical issues are critical. Understanding skills gap between existing arrangements for the management of offshore and onshore major accident hazards with respect to hydrogen is of particular importance.

UK content

Stakeholders consulted as part of this project identified the current offshore and onshore workforce as being ideally suited to support the repurposing of existing offshore infrastructure for hydrogen production. However, stakeholders raised concern that skills gaps existed that could affect the ability of an individual to adapt to new opportunities where knowledge and experience of hydrogen safety and technical issues are critical.

This study has highlighted the lack of an electrolyser manufacturer in Scotland to take advantage of the expected growth in commercial demand for the equipment in the domestic market and more widely. Addressing this deficit should be regarded by policy makers as a priority item for consideration.

Decommissioning

This study has identified clear synergies with the late life management and decommissioning of offshore oil and gas infrastructure.

- Scotland benefits from having a number of suitably sized yards and supply chain contractors experienced in all elements of decommissioning and recycling;
- The yards are ideally located in relative proximity to end of life assets or retrofit candidates to take advantage of an emerging market for the repurposing of offshore infrastructure;
- Notwithstanding the positive attributes, it must be recognised that decommissioning presents a number of conflict scenarios such as continued availability of infrastructure before it is decommissioned. Repurposing may also be seen as a driver for deferral.

[2] The Construction (Design and Management) Regulations 2015

Recommendations

It is recommended that further work be conducted to:

1. Further refine costs models, consistent with advances in our understanding of safety and technical risk management to help drive down costs;
2. Better understand benchmark costs for the removal of major components such as topsides module(s) from "donor" platforms;
3. Better understand financial liabilities associated with the repurposing of existing installations which are in late life or would otherwise be decommissioned;
4. Consider cost of onshore new build facilities as these have not been assessed within this study;
5. Better understand the potential for reuse of recycled material; this is the focus of the NexStep initiative in the Netherlands;
6. Expand decommissioning guidance to highlight potential re-use options for hydrogen production and other power generation scenarios to ensure all alternatives are considered in detail;
7. Define mechanisms for the transfer of liability, noting that this could be particularly complicated where candidate infrastructure is one part of an asset e.g. one pipeline on an asset out of a possible six exiting the structure;
8. Consider full integration of hydrogen alongside CCS / CCUS;
9. Consider the price of carbon as an influencing factor in the success of the hydrogen economy and a low carbon economy. In this context, consideration should be given to further development of carbon pricing and taxation schemes to encourage transition to net zero;
10. Better understand regulator roles and responsibilities, regulations, codes and standards in order to confirm adequacy of existing arrangements, identify gaps and the potential for transfer from one application to another. In particular, where there is a difference in the perception of stakeholders and the extent to which the regulatory regime addresses all hazards and risk factors associated with a repurposing scenario, there is a requirement to understand the similarities, differences, knowledge gaps, and to identify areas where knowledge transfer between regulatory regimes is possible.
11. Review management arrangements to understand the similarities, differences, knowledge gaps and areas where knowledge transfer is possible between HSE management systems.
12. Understand the skills gap between existing arrangements for the management of offshore and onshore major accident hazards with respect to hydrogen.
13. Fully understand the contribution gas to graphene can make to the economics of hydrogen generation, in the context of repurposing of existing offshore installations.
14. Review challenges associated with the repurposing of available pipelines for pure hydrogen and hydrogen / methane blends to understand, economic uncertainties associated with the condition of redundant pipelines, corrosion and integrity issues associated with hydrogen transportation duties, physical and chemical differences between hydrogen and natural gas (methane) and concerns regarding stress cracking; and pipeline availability / compatibility with decommissioning plans.
15. Review challenges associated with the repurposing of available pipelines to understand, economic uncertainties associated with the condition of redundant pipelines, corrosion and integrity issues associated with hydrogen transportation duties, physical and chemical differences between hydrogen and natural gas (methane) and concerns

regarding stress cracking; and pipeline availability / compatibility with decommissioning plans.

16. Address the lack of an electrolyser manufacturer in Scotland to take advantage of the expected growth in commercial demand for the equipment in repurposing and new build projects.
17. Realise the potential of SMR as a net zero enabler; there is a need to consider the linkage between offshore application of the technology and the road to a low carbon future.
18. Realise the potential of gas to graphene technology in the context of a net zero operating strategy.
19. Develop an economic cost model to allow a comprehensive comparison of hydrogen generation projects based on the use of re-purposed infrastructure, new build and an onshore hydrogen production facility. The model should be developed as a joint industry initiative.

Prioritisation of recommendations

For the purposes of prioritisation, we have used the data derived from our analysis of risks and opportunities to assign priorities to general groups. The graphical representation of the data (see Figure 1) identifies priority elements according to level of maturity (where low number signifies low level of maturity and implies a higher level of effort to realise market potential). Importantly, the graph is not intended to suggest an order in which actions should be scheduled. Prioritisation decisions on how, or when to address "low hanging fruit" or the more demanding issues should be agreed in consultation with stakeholders.

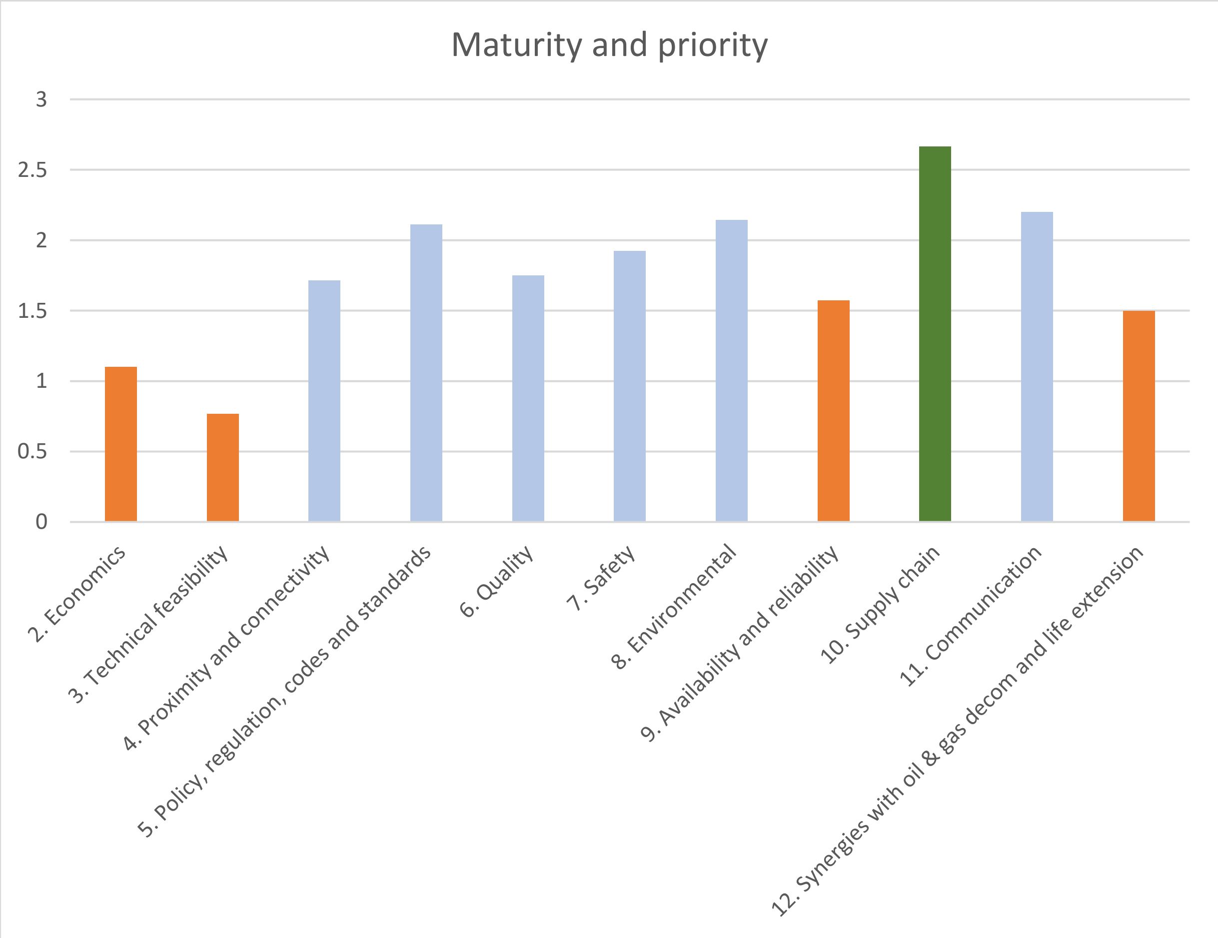

Figure 1. Maturity and priority.

Priority group 1

Those elements associated with the repurposing agenda seen to be least mature, and therefore regarded as being priority items for further development are the related areas of economics and technical feasibility.

The availability and reliability of plant and equipment should also be considered in this context. That is, the availability and reliability of equipment and plant associated with constant supply of renewable energy from offshore wind farms; storage capacity for hydrogen and CO_2; use of raw seawater and corrosion; remaining life span of infrastructure from sea-bed to surface.

Priority group 2

Elements regarded as being relatively mature have their origins in the oil and gas industry, which has been developed over a period of 40 years. These elements are:

- Proximity of candidate infrastructure to hydrogen demand centres, generation locations and the supply chain; and
- Organisational and management elements associated with policy, regulation, QHSE and communication; and
- Synergies with oil and gas decommissioning and asset life extension;

Priority group 3

The supply chain category accounts for local workforce and international networks in terms of supply bases, port facilities, marine operations, aviation, project management, engineering and more. In common with the elements of Priority group 2, the maturity and ability of this cohort to be re-purposed towards an offshore hydrogen economy has its genesis in over 40 years' oil and gas experience.

Acknowledgements

The team that researched and prepared this report was led by Ian Thomas and included Kevin Fitzgerald, Nikkii Ng and Graham Pittendrigh.

The work was sponsored by SOWEC with support and advice from Chris Pearson of SOWEC and Sian Wilson, Colin Maciver and Jalissa Zupo of Crown Estate Scotland, and Andrew Stormonth-Darling of ORE Catapult.

Stakeholder organisations consulted for the report

The following stakeholder organisations provided input to the report:

- Augean;
- Bridge Petroleum;
- British Geological Survey;
- Cambridge Nanosystems;
- Decom North Sea;
- EnQuest;
- Lloyd's Register;
- Neptune Energy;
- Ocean Winds;
- OGA;
- Oil and Gas UK;
- Oil and Gas Technology Centre;
- Orion Clean Energy Project;
- ORE Catapult; and
- Siemens.

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1. Introduction

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The report documents the findings of a feasibility study undertaken by Vysus Group to identify opportunities and risks associated with the repurpose of oil and gas infrastructure for offshore hydrogen production.

The assignment was conducted as a desk study over a period of 12 weeks, January 2021 to end March 2021 and involved a review of publicly available information and in-house data sources together with consultation with a range of stakeholders.

It is expected that this report shall be of interest to a broad range of organisations involved in the generation of hydrogen offshore. Organisations will include developers, operators, EPC contractors, equipment manufacturers, specialist contractors, policy makers, regulators and other key stakeholders.

The report is also expected to be of interest to those organisations considering asset life extension, net zero modifications and decommissioning of offshore assets.

Stakeholders and interested parties consulted during the study included a representative sample from those groups that are involved with the generation of hydrogen power and those that are concerned with asset life extension and decommissioning.

1.1. Background to SOWEC and the study

SOWEC is a new group established in partnership between the Scottish public sector and the offshore wind industry.

The group is co-chaired by Scottish Energy Minister, Paul Wheelhouse, and Brian MacFarlane of SSE.

The purpose of the SOWEC group is to is to co-ordinate a Scotland-wide response to the Offshore Wind Sector Deal and to work directly with the DeepWind and Forth & Tay Offshore clusters.

The SOWEC vision is to establish an offshore wind sector that plays to Scotland’s strengths, delivering jobs, investment and export opportunities in line with the UK Sector Deal as a key part of the path to net zero.

Key goals of the SOWEC organisation are to:

- Deliver at least 8GW of offshore wind in Scottish waters by 2030;
- Develop a plan for offshore wind’s contribution to achieving Scotland’s climate change ambition of net zero greenhouse gas emissions by 2045;
- Create a competitive, commercially-attractive offshore wind sector in Scotland which can deliver both domestically and in the global offshore wind market, with a focus on project development, deeper water capability and innovative technology solutions;
- Work to increase local content in line with the ambitions set out in the UK Sector Deal, developing a sustainable, world-class supply chain in Scotland; and
- Increase the number of offshore wind jobs in Scotland to more than 6,000; an increase of 75% on 2019 figures.

As part of its vision, SOWEC has established sub-groups to consider alternative applications for offshore wind besides the normal electricity to the grid business model. In this context the

Power 2 X sub-group is considering the repurposing of existing oil and gas infrastructure for the offshore generation of hydrogen.

The present study is intended to bring the combined experience of the offshore wind and the oil and gas sector to the knowledgebase (SOWEC, 2021).

2. Terms of reference

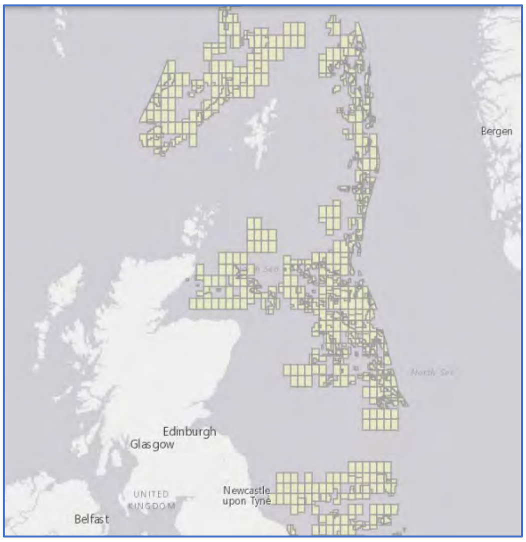
The purpose of this study was to identify key risks and opportunities for the repurposing of oil and gas infrastructure for the offshore generation of hydrogen.

The technical focus of the study was repurposing of infrastructure for use in the generation and transmission of blue and green hydrogen offshore, specifically:

- the availability of existing infrastructure such as platforms (incl. pipelines, ports/ reception facilities, storage facilities, offshore wind farms; and
- the suitability of equipment associated with the infrastructure.

The geographical scope was restricted to infrastructure located in Scottish Waters, although, it is recognised that findings of the report may be applied internationally.

Figure 2. Existing Oil & Gas infrastructure in UKCS. Source: (OGA Open Data interactive map., 2021).



Aspects considered within the study included:

- The enabling regulatory framework;
- The availability of commercially useable infrastructure;
- The identification of risks and mitigations for developers (safety, environmental, supply chain, technology, licensing, navigation, access to legacy assets);
- Local content and the availability of a skilled workforce;
- The demand for hydrogen;
- The cluster approach to growth (geographical and supply chain); and
- The capacity to capitalise on the offshore hydrogen opportunity.

3. Methodology and project execution programme

This assignment was conducted as a desk study, using publicly available data sources, in-house data sources and via consultation with key stakeholders.

Individual tasks required to complete the work scope were conducted over a 12 week timeframe in accordance with an agreed project execution programme.

A summary of the project execution programme is reproduced below. A detailed account of tasks specified in the agreed workscope is presented in the appendices.

Further detail regarding individual study methodologies is presented in the corresponding sections of this report.

Figure 3. Project execution programme.

Stage	Alignment with activity / study areas identified in 11.2.4
Stage 1. Set boundaries of study / review;	0 Kick off meeting with Crown Estate Scotland and the Scottish Offshore Wind Energy Council (SOWEC) to agree way of working, expectations and process to engage with key stakeholders.
Stage 2. Scoping to identify activities / processes within study boundary;	
Stage 3. Conduct review of publicly available literature;	1 Overview of development and consenting processes. 2 Availability and suitability of electrolyser technologies. 3 Best use of existing infrastructure. 4a Cost estimation for key enabling hydrogen supply chain capability and infrastructure. 4b Cost comparison.
Stage 4. Develop and use question set to consult with stakeholders. - **Verify findings of the literature review;** - **Identify gaps in the literature review data;** - **Identify areas for further study;** - **Iteration.**	5 Stakeholder consultation. 5a. Preparation of question set. 5b. Issue consultation questionnaire to consultees. 5c. Collate and assess responses from consultation process. 5d Follow up on a sub-set of responses. 6 Identification of risks, opportunities and priorities (Risk assessment study.) 7. Mitigation study.
Stage 5. Compile report, taking account of information gained from research.	8 Compile report. 9. Review report. 10. Issue report.

The strategy and framework for the study were informed by a hierarchy of international agreements on climate change; national policies and regulations; industry guidance; and codes and standards of relevance to the generation of offshore wind, offshore generation of hydrogen and repurpose of offshore installations. The study also considered policy, regulation, and industry guidance where this impinged on decommissioning, asset life extension and related net zero objectives relevant to the operation of offshore installations.

Where maps and plans have been used in the main body of the report to highlight the location of key infrastructure, we have included full page reproductions in the appendices to compensate for the small scale.

The layout of the report is intended to reflect the contract specification communicated by SOWEC, the agreed work plan and a logical approach to the presentation of information.

Figure 4.Layout of report and study topics.

Scoping study and overview of existing infrastructure and fundamental approach to hydrogen generation.

- A scoping study and overview of existing infrastructure including transmission lines and platforms for generation and transmission:
  - –Technologies for the production of offshore hydrogen;
  - –Conceptual models and scenarios;
  - –Equipment associated with the infrastructure;
- Location of energy hubs relative to existing oil and gas infrastructure candidates:
  - –Location of energy hubs and service amenities;
  - –Location of existing oil and gas infrastructure candidates for re-purposing.

Overview of development and consenting processes.

- An overview of development and consenting processes for commercial scale offshore green and blue hydrogen production in the UK.

Overview of different electrolyser technologies.

- An overview of different electrolyser technologies, with identification of those most suited for offshore hydrogen production.

Overview of cost estimates and comparison.

- Overview and cost estimation for key enabling hydrogen supply chain capability and infrastructure including existing offshore oil and gas infrastructure, electrolyser supply, port and quayside infrastructure, reinforced quayside areas (with services), operation and maintenance marine and quayside operations;
- Cost comparison, and benefit analysis of onshore vs offshore hydrogen production.

Overview of project risks and opportunities.

- Identification and assessment of project risks and opportunities:
- –Identification of generic "risks" for a project developer, identified through review of process and engagement with relevant stakeholders;
- –Identification of mitigations to the risks identified, their impact scored, and potential actors identified;
- –Identifying where generic opportunities in this process exist for a project developer.

Conclusions and recommendations.

- Presentation of conclusions and recommendations:
- –Capacity to deliver strong pipeline of hydrogen projects from late 2020s to 2050;
- –Consideration of desired UK content targets (including where relevant Scottish Government ambition for local content in ScotWind projects);
- –Consideration of industry demand in likely hydrogen clusters; and
- –Prioritised recommendations for further work, consistent with SOWEC energy transition vision.

4. Scoping study and overview of the fundamental approach to best use of infrastructure for hydrogen generation and transmission

This element of the study is intended to provide an overview of existing oil and gas infrastructure for the generation and transmission of offshore hydrogen. It is concerned with the fundamentals of hydrogen generation; the identification of hydrogen generation technologies; conceptual models; scenarios and oil and gas infrastructure with the potential for repurpose.

The scoping study and overview are intended to act as an anchor point for supporting technical studies and to enable a preliminary identification of:

- available infrastructure with the potential for repurposing for the production of offshore hydrogen;
- adjacent sources of wind and hydrocarbon feedstock for generation of green and blue hydrogen; and
- product export routes by pipeline or sea.

4.1. Technologies for the production of offshore hydrogen

Within the context of this study, three methods for the production of hydrogen were investigated. These are:

- Electrolysis;
- Steam methane reforming; and
- Gas to graphene.

Electrolysis

Electrolysis is a process whereby electricity is used to split water molecules into hydrogen and oxygen.

The three main types of electrolyser technologies are Solid Electrolyser Cells (SOECs), Proton Exchange Membrane (PEM) Cells and Alkaline Electrolysis Cells (AECs).

Steam methane reforming (SMR)

SMR is a high temperature, endothermic catalytic process which combines methane (CH_4) with water (H_2O) to produce hydrogen (H_2). A by-product of the process is CO_2 which is produced at a ratio of 1 molecule of CO_2 to 4 molecules of H_2.

Gas to graphene (G2G)

Gas to graphene technology uses a microwave plasma reactor to break down methane gas into hydrogen and elemental carbon atoms. The atoms are recombined into graphene sheets by floating them in the hydrogen atmosphere. The output from the plasma reactor is a mixed stream composed of hydrogen gas, acetylene gas, methane gas and graphene.

Within this report G2G is regarded as producing blue hydrogen on the basis of the output stream composition.

4.2. Conceptual models and scenarios

In evaluating the potential reuse of existing infrastructure and equipment for use with the candidate hydrogen generation technologies, our review of conceptual models and scenarios considered:

- the availability of existing infrastructure such as platforms (pipelines, ports/ reception facilities, storage facilities, offshore wind farms); and
- suitability of equipment associated with the infrastructure.

Within this context, the scoping element of the study used the data sources cited below to identify six repurposing and retrofit scenarios for the generation of offshore hydrogen (refer to Section 4.3). The criteria used for the selection of the scenarios were based on:

- the availability of existing oil and gas infrastructure (surface and subsurface);
- scale of structure to act as a host facility (NS and CNS – large assets, SNS – smaller NUIs);
- proximity to energy generating hubs (OWFs);
- proximity to demand centres;
- proximity to CCUS projects;
- operational status;
- and decommissioning status.

The six scenarios are identified in the table below.

Figure 5. Scenarios associated with Hydrogen production technologies.

Scenario	Key elements
1. Wind & Electrolysis (Constrained Offshore Renewable Resources)	Green hydrogen. Electrolysis housed in floating asset. Renewable source of power, nearby OWF. Hydrogen export to Shetland via FLAGS or new pipeline. Modular design installation.
2a Large Asset with Electrolysis (Repurposing of Large Offshore Assets)	Green hydrogen. Repurpose of large offshore asset with electrolysis. Renewable source of power, nearby OWF. Hydrogen export to Shetland via FLAGS or new pipeline. Modular design installation
2b. Large Asset with SMR (Repurposing of Large Offshore Assets)	Blue hydrogen. Repurpose of large offshore asset with SMR. Feed gas supplied by new pipeline from nearby asset or Brent infrastructure. Carbon dioxide sequestered via offshore CCUS. Modular design installation
2c Large Asset with G2G (Repurposing of Large Offshore Assets)	Blue hydrogen. Repurpose large asset for production of graphene using gas to graphene technology. Modular design installation. Graphene product shipped to shore.
4b Retrofit SMR (Retrofitting an Existing Asset)	Blue hydrogen. Retrofit of offshore asset with SMR. Feed gas from nearby asset (SNS). Carbon dioxide sequestered via offshore CCUS. Purpose: to reduce GHG emissions and create revenue from sale of hydrogen to neighbouring asset. Modular design installation.
4c Retrofit G2G (Retrofitting an Existing Asset)	Blue hydrogen. Focus on assets that currently flare gas and are not planned to be decommissioned in the near future. Retrofit asset for production of graphene using gas to graphene technology. Modular design installation. Graphene product shipped to shore.

4.3. Data sources used to identify scenarios and related infrastructure

Data sources used to identify scenarios and related infrastructure in this section of the report included:

- Oil and Gas Technology Centre - 1 HS413 Phase 1 Project Report Phase 1 Project Report (OGTC (Phase 1 project report, HS413), 2019);
- Oil and Gas Authority - UKCS Energy Integration Interim findings (OGA, 2019)
- Oil and Gas Authority - Energy Integration Realising Cross-Sector Integration on the UKCS to Support UK's Energy Transition (Lloyd's Register)
- Department for Business, Energy & Industrial Strategy - Dolphyn Hydrogen, Phase 1 - Final Report (BEIS - Dolphyn, 2019)
- Oil and Gas Authority - PosHYdon Pilot Offshore green hydrogen (OGA, 2019)
- Scottish Government - Scottish Offshore Wind to Green Hydrogen Opportunity Assessment (Scottish Government, 2020)
- Institution of Civil Engineers - Far from shore floating wind farms and associated emerging technologies – briefing sheet. (Neil Glover, Institution of Civil Engineers, 2019)
- Nexstep National Platform for re-use and decommissioning (Nexstep, 2021)

4.4. Key features and configurations associated with each scenario.

Existing infrastructure identified as potential hosts for the three hydrogen generation technologies are identified as:

- a floating offshore unit;
- large fixed installation;
- stranded well;
- product export pipeline; and
- feedstock import pipeline.

The key features and configurations of each scenario are summarised below.

Figure 6. Scenario 1- Electrolysis housed in floating asset.

Scenario 1 – Wind & Electrolysis (Constrained Offshore Renewable Resources)	Description and assumptions	Offshore infrastructure and equipment requirement identified in scenarios
Green Hydrogen	This scenario is based on access to the most abundant UK renewable energy resources that lie to the north of the Scottish mainland. The scenario assumes: • floating wind and electrolysis shall be used to generate hydrogen which is exported via a hydrogen pipeline to Shetland where it can be stored and exported further by ship. • a PEM electrolysis unit shall be housed in a converted bulk carrier with the electrical supply from the individual wind turbines gathered through a single point mooring (SPM). • high purity green hydrogen (99.999%) would be transported to Shetland for storage and export via a short, dedicated pipeline."	Bulk carrier (Sub- structure) FPSO (Sub- structure) Single point mooring system Hydrogen export via new pipeline Wind turbines.

Figure 7. Scenario 2a - Repurpose of large offshore asset with electrolysis.

Scenario 2a – Large Asset with Electrolysis (Repurposing of Large Offshore Assets)	Description and assumptions	Offshore infrastructure and equipment requirement identified in scenarios
Green Hydrogen	This scenario is based on the repurposing of the large (fixed) offshore assets in the Northern North Sea (NNS) and the Central North Sea (CNS). This scenario assumes: • the installation of electrolysers on a decommissioned structure such as Brent Bravo or Delta. • the hydrogen produced from floating wind and electrolysis on the repurposed platform would either be exported as a blended product into the FLAGS pipeline or via a new dedicated pipeline.	Brent infrastructure (Sub-structure) FLAGS pipeline.

Figure 8. Scenario 2b - Repurpose of large offshore asset with SMR

Scenario 2b – Large Asset with SMR (Repurposing of Large Offshore Assets)	Description and assumptions	Offshore infrastructure and equipment requirement identified in scenarios
Blue Hydrogen	This scenario is based on the full re-purposing of asset topsides and repurposing of the large (fixed) offshore assets in the Northern North Sea (NNS) and the Central North Sea (CNS). This scenario assumes: • natural gas, required for reforming, will be sourced via a new pipeline from a nearby asset (base case) or Brent infrastructure (assumed up to 10km distance). • the hydrogen produced via this process would then be exported via far north liquids and associated gas (FLAGS) pipeline as a blended product (assumed 2km of pipeline required). • the CO_2 produced would be exported to a nearby asset for subsurface storage (assumed up to 10km distance).	Brent infrastructure (Sub-structure) (FLAGS) pipeline.

Figure 9. Scenario 2c - Repurpose large offshore asset to host G2G technology.

Scenario 2c – Large Asset with G2G (Repurposing of Large Offshore Assets)	Description and assumptions	Offshore infrastructure and equipment requirement identified in scenarios
Blue Hydrogen	This scenario is based on the full re-purposing of asset topsides and repurposing of the large (fixed) offshore assets in the Northern North Sea (NNS) and the Central North Sea (CNS). This scenario assumes	Brent infrastructure (Sub-structure) (FLAGS) pipeline Port infrastructure (unspecified).

Scenario 2c – Large Asset with G2G (Repurposing of Large Offshore Assets)	Description and assumptions	Offshore infrastructure and equipment requirement identified in scenarios
	• natural gas used in the gas to graphene process will be sourced from a nearby asset (base case) or through Brent infrastructure. • electricity required to power the process may be supplied by renewable or non renewable sources. • hydrogen produced via the gas to graphene process would then be exported via FLAGS as a blended product. • graphene would be transported via ship to shore.	

Figure 10. Scenario 4b - Retrofit of offshore asset with SMR. Feed gas from nearby asset (SNS).

Scenario 4b – Retrofit SMR (Retrofitting an Existing Asset)	Description and assumptions	Offshore infrastructure and equipment requirement identified in scenarios
Blue Hydrogen	This scenario is specifically focused on assets that currently flare gas and are not planned to be decommissioned in the near future. Flaring typically occurs because the asset in question is stranded, has limited gas processing capability and / or limited access to a gas export route and as a result cannot dispose of the gas accordingly. This scenario assumes: • hydrogen will be exported to an existing hydrocarbon pipeline. • The CH_4 feedstock will be derived from flare gas or from a stranded well.	Fixed platform, FPSO or NUI (Sub- structure) Production asset or stranded well.

Figure 11. Scenario 4c G2G – Retrofit of offshore asset with G2G technology. Feed gas from nearby asset (SNS).

Scenario 4c – Retrofit asset for production of graphene	Description and assumptions	Offshore infrastructure and equipment requirement identified in scenarios
Blue Hydrogen	The scenario is specifically focused on the retrofitting of operational assets that currently flare gas and are not planned to be decommissioned in the near future. Flaring typically occurs because the asset in question is stranded, has limited gas processing capability and / or limited access to a gas export route and as a result cannot dispose of the gas accordingly. Repurposing for graphene assumes: • natural gas will be sourced from an existing production asset or stranded well.	Fixed platform, FPSO, NUI (Sub- structure) Production asset or stranded well.

Scenario 4c – Retrofit asset for production of graphene	Description and assumptions	Offshore infrastructure and equipment requirement identified in scenarios
	• electricity required to power the process may be supplied by renewable or non renewable sources • the hydrogen produced via this process would be exported via existing pipeline as a blended product. • graphene product will be transported via ship to shore.	

4.5. Equipment associated with the infrastructure

In order to inform an assessment of the suitability of available infrastructure, this study derived a high level list of key equipment from the offshore hydrogen generation scenarios reviewed. The list is representative of equipment associated with green and blue hydrogen generation scenarios. The list is presented in **Appendix C**.

The suitability of available infrastructure and associated equipment is addressed in the identification and assessment of project risks and opportunities which takes account of key suitability factors such as compliance with regulation, codes and standards, technical feasibility, economics, proximity and supply chain issues (refer Section 8).

The decision to drill down to the equipment level was strengthened by the BEIS Phase 1 Dolphyn report and the Nexstep Hackathon series of reports which identify key equipment as having the potential to be re-used and recycled.

4.6. Location of energy hubs and service amenities

This section provides an overview of the location and proximity of the re-purposing infrastructure candidates to the energy hubs that they are expected to serve.

In this section, we consider the location and relative proximity of:

- Hydrogen demand centres (hubs);
- Offshore electricity generation (OWF);
- Offshore cabling and transmission; and
- Yards and port facilities.

To be considered a viable proposition, the location of infrastructure being considered for repurposing for hydrogen production must be located in relative proximity to an energy hub and service amenities.

The proximity of existing offshore installations, pipelines and depleted well formations to an energy hub offers the hydrogen generation effort the benefit of a substructure to locate hydrogen generating equipment, access to power via an electrified installation, an export route for product, an import route for feedstock gas and a disposal route for CO_2.

Proximity to the service hub benefits the repurposing effort by offering access to the yards and port facilities necessary to carry out the works necessary to convert an existing offshore installation to act as a host for hydrogen production activities.

*Note: Where maps and plans have been used in this section to illustrate location, full page maps are reproduced in **Appendix F.***

4.6.1. Hydrogen demand centres (hubs)

The Scottish Government report, "Scottish Offshore Wind to Green Hydrogen Opportunity Assessment" identifies the location of demand hubs for hydrogen to be in and around the North and East coasts of Scotland.

Figure 12. Future Hydrogen projects and associated demand hubs in Scotland.

Hydrogen demand hubs identified in the Scottish Government report are listed here.

Figure 13. Hydrogen demand hubs.

Hydrogen demand hubs	
Shetland	HOP and Orion
Orkney	BIG Hit, Surf n Turf, ReFlex, HySpirits, Orkney Green Ammonia Plant, ITEG, PITCHES, Orkney H2 Strategy, HyDIME, HySEAS3
Cromarty	Cromarty Firth Green Hydrogen Hub
Aberdeen and North East	High V.LO-City, Acorn CCS and Hydrogen, H2 Aberdeen Hydrogen Bus, HyGEN, Huntly Hydrogen, HyTrec2 Aberdeen Vision, Aberdeen Hydrogen Hub
Fife and Dundee	Levenmouth Hydrogen Office, Project Methilltoune, HyGEN Hydrogen 100, JIVE and JIVE 2 Hydrogen Accelerator, Dundee Hydrogen Refuelling Station
Lothians	HyStorPor and SeaFuel
Glasgow	Green Hydrogen for Glasgow and Hydrogen Dual Fuel Gritters
Argyle	HyGEN
Western Isles	OHLEH, SWIFTH2, and HyFlyer

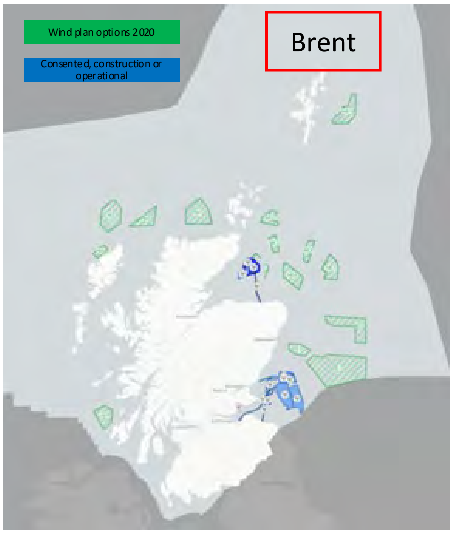
4.6.2. Offshore electricity generation (OWF)

The location of green hydrogen generation projects and repurposing candidates is dependent on the location of offshore wind farms and access to the cable array network.

Crown Estate Scotland and Marine Scotland identify wind generation sites in North and Central North Sea locations, and in relative proximity to existing oil and gas installations.

A composite view of existing Crown Estate Scotland Wind Lease Sites and Marine Scotland Sectoral Marine Plan (SMP) Options is presented here.

Figure 14. Composite view of existing wind lease sites. Adapted from the OGA Open Data interactive map, 2021.



The operational status of offshore wind developments identified in the Marine Scotland Sectoral Marine Plan (SMP) is presented below.

Figure 15. Operational status of offshore wind developments. Source, Offshore wind to green hydrogen: opportunity assessment. (Scottish Government, 2020)

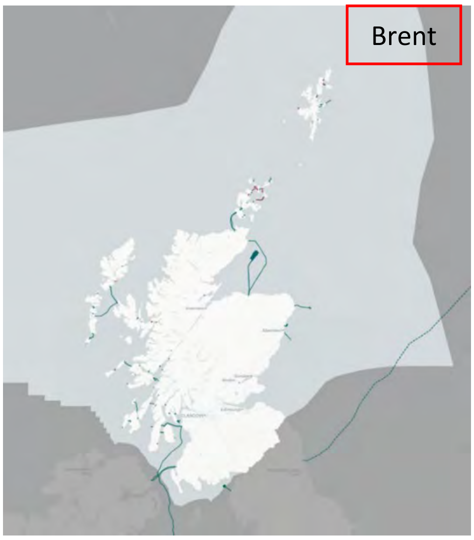
Current Scottish Offshore Wind Farms	Status	Capacity MW (max)
Aberdeen Offshore Wind Farm (EOWDC)	Fully Commissioned	93.2
Beatrice	Fully Commissioned	588
Hywind Scotland Pilot Park	Fully Commissioned	30
Kincardine - Phase 1	Fully Commissioned	2
Levenmouth demonstration turbine	Fully Commissioned	7
Robin Rigg	Fully Commissioned	174
Moray East	Under Construction	950
Neart na Gaoithe	Under Construction	448
Kincardine - Phase 2	Pre-Construction	48
Seagreen 1	Pre-Construction	1075
Inch Cape	Consent Authorised	1000
Moray West	Consent Authorised	950
Dounreay Trì	Consent Authorised	10
ForthWind Offshore Wind Demonstration Project Phase 1	Consent Authorised	29.9
Seagreen Extension	Consent Authorised	360
Berwick Bank & Marr Bank	Concept/Early Planning	3200
ForthWind Offshore Wind Demonstration Project Phase 2	Concept/Early Planning	53

4.6.3. Offshore cabling and power transmission

The location and proximity of cable routes associated with offshore wind farms and interconnectors between the UK and neighbouring countries are identified in Figure 16. The ability of offshore installations to tie into nearby cabling is fundamental to platform electrification and the generation of green hydrogen offshore.

As wind farm developments continue to grow to meet government policy objectives, then - assuming technical compatibility and economic feasibility - the ability of the hydrogen generation equipment and repurposed infrastructure to tie into an adjacent OWF cabling array is expected to grow.

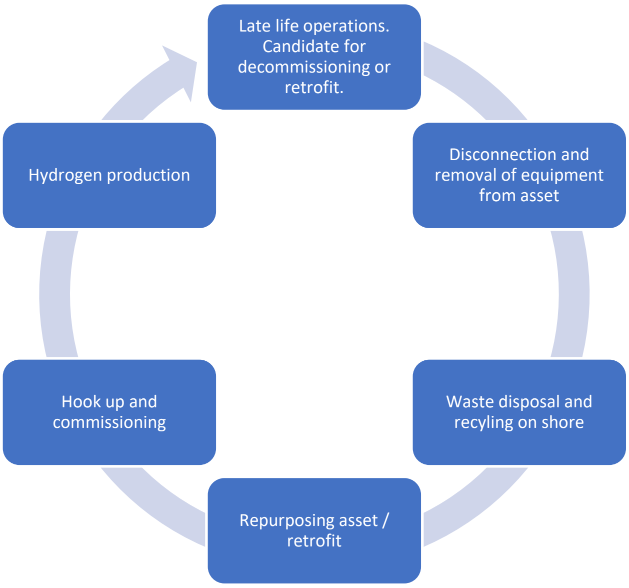
Figure 16. Renewable energy and power cable infrastructure. Source: Marine Scotland, Power Cables (KIS-ORCA), January 2020. Source: (Marine Scotland, MAPS NMPI, 2021).



4.6.4. Yards and port facilities

Proximity to suitable port infrastructure is necessary for the repurpose of existing oil and gas assets through the full project life cycle covering late life, pre clean, disconnection and removal, waste recycling, repurpose engineering, commissioning and production.

Figure 17. Asset life cycle, late life to hydrogen production.



4.6.5. Port infrastructure required for the recycling and repurpose of existing offshore infrastructure

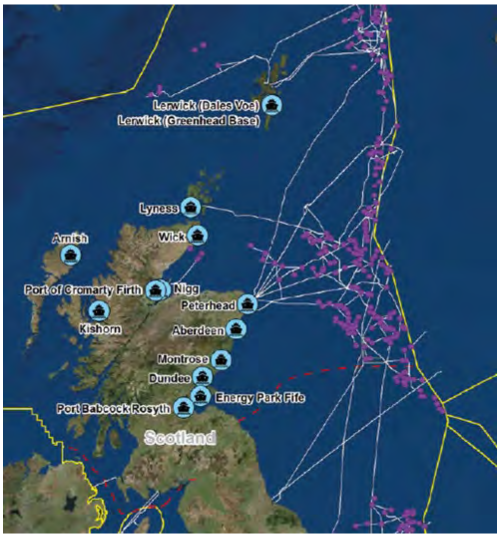
Port facilities with the capacity to repurpose existing oil and gas production assets will have to have the capability to deal with a range of materials:

- Piece Small - offshore demolition and dismantling with small pieces brought ashore;
- Piece Medium - medium scale elements brought ashore but typically not requiring special heavy lifting; and

- Piece Large - large elements including full topsides or modules, require heavy lifting / specialist craneage.

The location of facilities with the capacity to accept oil and gas infrastructure for recycling and repurpose will be the same facilities that will service the decommissioning sector. Their proximity to North Sea oil and gas infrastructure means they are ideally located to support repurposing activities. Most Scottish ports have already received infrastructure removed from offshore fields with local supply chains processing the material.

Figure 18. Scottish Ports and Proximity to UKCS Fields. Source: (HIE, SDI and SE, Oil & Gas Decommissioning Scottish Capability, 2018)



The physical site requirements will depend on waste received, handling and processing to be done at the port and scale of operations. Physical considerations will include:

- Water depth and navigable access;
- Appropriate quayside and berthing;
- Craneage;
- Laydown areas;
- Use of Self-Propelled Modular Transporters (SPMT);
- Waste Receiving and Processing Facilities;
- Waste Management Facilities;
- Processing Facilities; and
- Drainage and Containment.

Permits, licenses and consents will be required for the recycling and repurpose of:

- Deck / topside;
- Jacket;
- Cabling;
- Electrics;
- Pipelines;
- Mattresses;
- Accommodation blocks; and
- Moorings / Anchor chains.

Adapted from: (Ironside Farrar on behalf of Scottish Enterprise, Highlands and Islands Enterprise and Scottish Energy Ports, 2018).

4.6.6. Port infrastructure required for the construction, marshalling, assembly and servicing of wind farms

Minimum criteria for vessel traffic associated with wind farm construction and operation activities are similar to those cited for decommissioning facilities, in that ports will be required to have adequate water depth, unrestricted navigation, useable quayside areas to accommodate the load out and load in of large structures.

Port facilities identified by Crown Estate Scotland as meeting minimum criteria to support large scale construction, marshalling and servicing of wind farms necessary for the production of green hydrogen include:

- Lerwick (Dales Voe)
- Lerwick Greenhead base)
- Lyness
- Wick
- Arnish
- Wick
- Nigg
- Peterhead
- Aberdeen
- Montrose
- Dundee
- Cesscon Energy Park Fife
- Rosyth
- Kishorn
- Port of Cromarty

Figure 19. Courtesy of Augean, Decommissioning facility, Port of Dundee.

Key features of the Dundee site, as a typical example of the type of facility required to repurpose decommissioned oil and gas installations:

- PPC Permit;
- NORM Permits;
- 3 Permitted Quaysides, area >800m;
- 8.0-9.5m Draft;
- 80te/sq.m Heavy Lift pad;
- 1500te harbour crane;
- 10,000sq.m NORM decontamination facility;
- 60 acres laydown; and
- total loading capacity 45,000te.

4.7. Location of existing oil and gas infrastructure candidates for repurposing

In this section of the report we address the location and relative proximity of existing oil and gas infrastructure to the energy hubs and service centres, taking account of:

- Pipelines;
- Surface infrastructure;
- CCUS infrastructure, and
- Subsurface infrastructure.

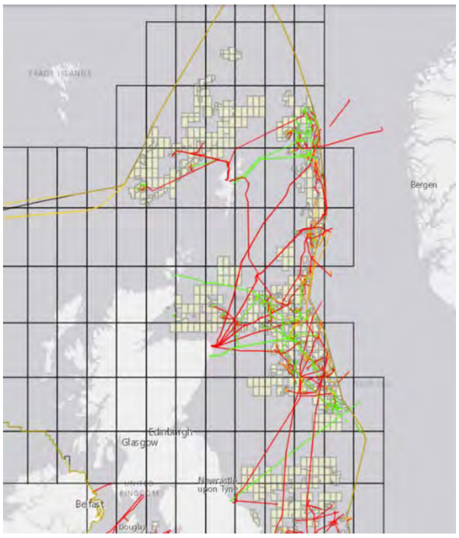
Data sources used in the preparation of this section include:

- OGA Open Data Interactive Map;
- Marine Scotland Maps, NMPI;
- IOGP Global CCUS Projects; and
- Pale Blue Dot.

4.7.1. Pipelines

Existing oil and gas pipelines which may be considered as repurposing candidates for the export or storage of hydrogen product, disposal of CO_2 and the import of CH_4 feedstock for SMR operations are situated in the Northern North Sea (NNS) and Central North Sea (CNS), in relative proximity to Offshore Wind Farms and CCUS candidate facilities (see Figure 20).

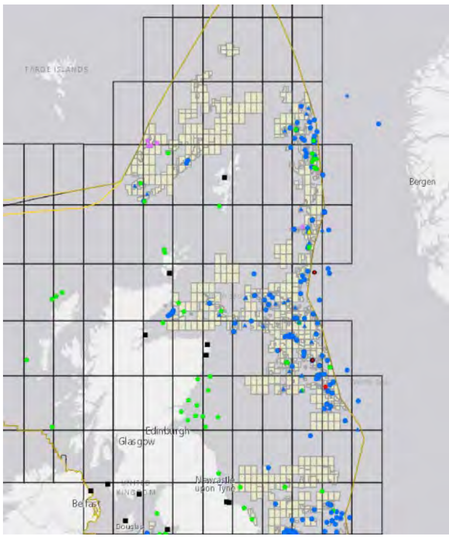
Figure 20. Infrastructure pipelines and licenced blocks. Source; (OGA Open Data Interactive Map, 2021).



4.7.2. Surface infrastructure

Existing elements of surface infrastructure which may be considered as repurposing candidates to host hydrogen generation equipment are located in the NNS and CNS. The larger fixed installations are located in the NNS and CNS. Smaller NUIs are located in the Southern North Sea (SNS) (see Figure 21).

Figure 21. Surface infrastructure and licenced blocks. Source; (OGA Open Data interactive map, 2021).



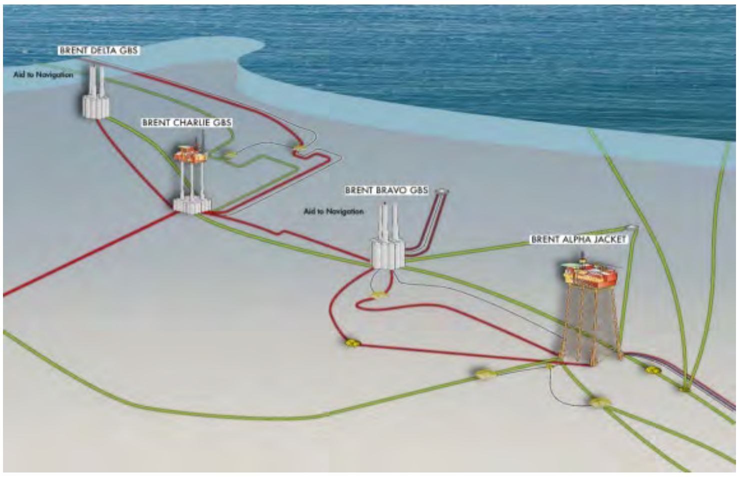
In studies conducted by OGTC, it is the repurpose of larger installations such as Brent Bravo or Delta that are being considered to host hydrogen generation equipment once decommissioned as oil and gas production facilities. In this scenario, OGTC envisage a full repurposing of the topsides.

The smaller NUIs may be repurposed as substructures to host electrical substations or similar ancillary equipment.

Where the existing installation is operational and is not in a late life, decommissioning situation, it is envisaged that the topsides may be fully repurposed to host SMR process equipment. The OGTC scenario is based on the repurposing of the large (fixed) offshore assets in the NNS and the CNS. In the NNS, it is the Brent infrastructure that has been identified as the base case candidate for post hydrocarbon, hydrogen service.

The decommissioning programme for the Brent group of assets is currently ongoing to an extent that topsides have been removed and pipeline decommissioning is underway. Options are now being considered for the remaining structures and pipelines. These options include, repurposing for alternative duties.

Figure 22. Layout of remaining installations in the Brent field. Source: (SHELL, Brent field decommissioning programme., 2021)



The base case example that has been selected is in the Brent field where there is good access to several key resources for hydrogen production. This includes assets that produce gas (to be used for SMR and G2G), export routes for hydrogen and other products, prospects for CCS and already decommissioned assets.

Source: (OGTC (Phase 1 project report, HS413), 2019)

Other gravity-based structures (GBS) which have been decommissioned or will shortly be decommissioned, and which are candidates for a repurposing concept such as hydrogen production are identified in the figure below.

Source, Lloyd's Register.

Figure 23. Gravity based structures which have been decommissioned or are awaiting decommissioning.

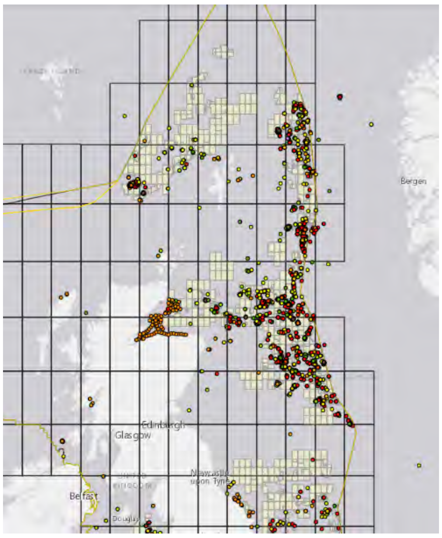
Name	Type	Water Depth	Year of Installation	Status
Beryl A	Condeep 3 shafts	118 m	1975	Operating
Frigg CDP1	CGS 1 shaft, Jarlan Wall	104 m	1975	Decommissioned, topsides removed
Brent D	Condeep 3 shafts	140 m	1976	Decommissioned, topsides removed
Frigg TP1	CGS 2 shafts	104 m	1976	Decommissioned, topsides removed
Frigg MCP-01	CGS	104 m	1976	Decommissioned, topsides removed
Dunlin A	CGS 4 shafts	153 m	1977	Decommissioning Plan Approved, ongoing
Cormorant A	CGS 4 shafts	149 m	1978	Operating
Ninian Central	CGS 1 shaft, Jarlan Wall	136 m	1978	Operating
Brent C	CGS 4 shafts	141 m	1978	Decommissioning Plan Approved
Harding	CGS	109 m	1996	Operating

4.7.3. Subsurface infrastructure

The location of subsurface infrastructure associated with oil and gas production, not identified as a pipeline is presented here (see Figure 24).

This subsurface infrastructure includes well heads, manifolds, mattresses and other subsea equipment. This may have repurposing potential but will have only limited impact on the overall cost of a hydrogen generation project.

Figure 24. Subsurface infrastructure and licenced blocks. Source: (OGA Open Data interactive map, 2021)



4.7.4. CCUS infrastructure

A by-product of hydrogen production using SMR technology is CO_2 which must be managed and disposed of responsibly.

SMR reaction

SMR is a process whereby hydrogen is generated from the reaction of methane (CH_4) and water (H_2). The process is endothermic requiring a temperature of approximately 800'C and the presence of a catalyst. The SMR process produces one molecule of CO_2 for every four molecules of hydrogen (H_2) produced, with the steam contributing the additional hydrogen.

In this series of reactions, natural gas (CH_4) is reacted with steam at an elevated temperature to produce carbon monoxide (CO) and (H_2) hydrogen. A subsequent reaction — the water gas shift reaction — then reacts additional steam with the carbon monoxide to produce additional hydrogen (H_2) and carbon dioxide (CO_2).

This SMR process produces one molecule of CO_2 for every four molecules of hydrogen (H_2) produced, with the steam contributing the additional hydrogen.

1) $CH_4 + H_2O \Leftrightarrow CO + 3H_2$
2) $CO + H_2O \Leftrightarrow CO_2 + H_2$

Subsurface disposal

As CO_2 is a greenhouse gas it is assumed that it will be exported to a nearby asset for subsurface storage and long term disposal in a CCUS facility. This is consistent with UK Government policy which recognises that the technology could offer significant flexibility and optionality in hard to decarbonise sectors, which will be crucial in the transition to net zero.

CCUS

CCUS is not a new technology: the capture process has been around since the 1930s. The process consists of capturing CO_2 produced by large industrial plants (such as power plants, refineries, steel mills, and cement plants, and hydrogen production plants), compressing it for transportation via pipeline or ship, and then injecting it into underground rock formations at carefully selected sites. The CO_2 can be stored in dedicated storage sites such as depleted oil and gas reservoirs or deep saline formations, or it can be injected underground for Enhanced Oil Recovery (EOR) purposes.

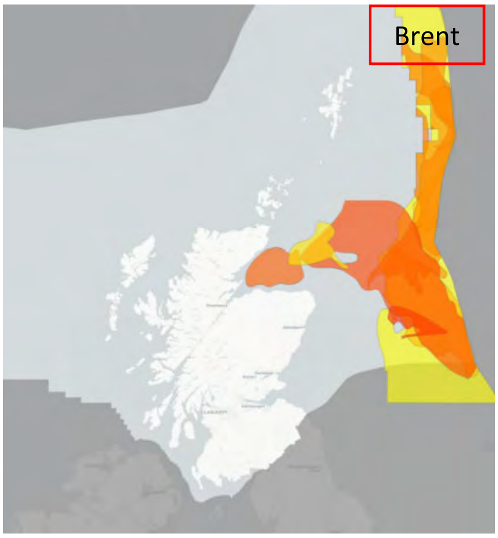
Source, IOGP, The CCUS process. (IOGP, 2021).

CO_2 storage locations

Carbon capture and storage aquifer areas identified in the Marine Scotland data set are located in Northern and Eastern locations of the North and Southern UKCS (see Figure 25) and include:

- Balder
- Captain
- Flugga
- Forties
- Frig
- Grid
- Heimdal
- Mains
- Mey
- Tay

Figure 25. Proximity to CCUS saline aquifer areas. Source ; Marine Scotland, Carbon Capture and Storage - Saline Aquifer Areas, January 2009. Source: (Marine Scotland Maps NMPI, 2021).



CCUS projects in Scotland

CCUS projects are being progressed in Scotland via Acorn and Caledonia Clean Energy (see Figure 26).

Figure 26. CCUS projects in Scotland. Source, IOGP, Global CCUS projects. (IOGP, 2021).

LOCATION	PROJECT NAME	DESCRIPTION	STARTING DATE (OPERATION)	STATUS	PARTICIPANTS
UK St Fergus	Acorn	CCS-equipped natural gas processing plant, CO_2 transportation and storage in the North Sea.	2023	The BEIS CCUS funding is progressing the detailed engineering for this project towards a final investment decision in 2021.	Project is led by Pale Blue Dot Energy, with funding and support from industry partners (Chrysaor, Shell and Total) the UK and Scottish Governments.
UK Grangemouth	Caledonia Clean Energy	CCS-equipped natural gas power plant, CO_2 transportation and storage in the North Sea.	2023	Feasibility Study.	Summit Power.

Acorn

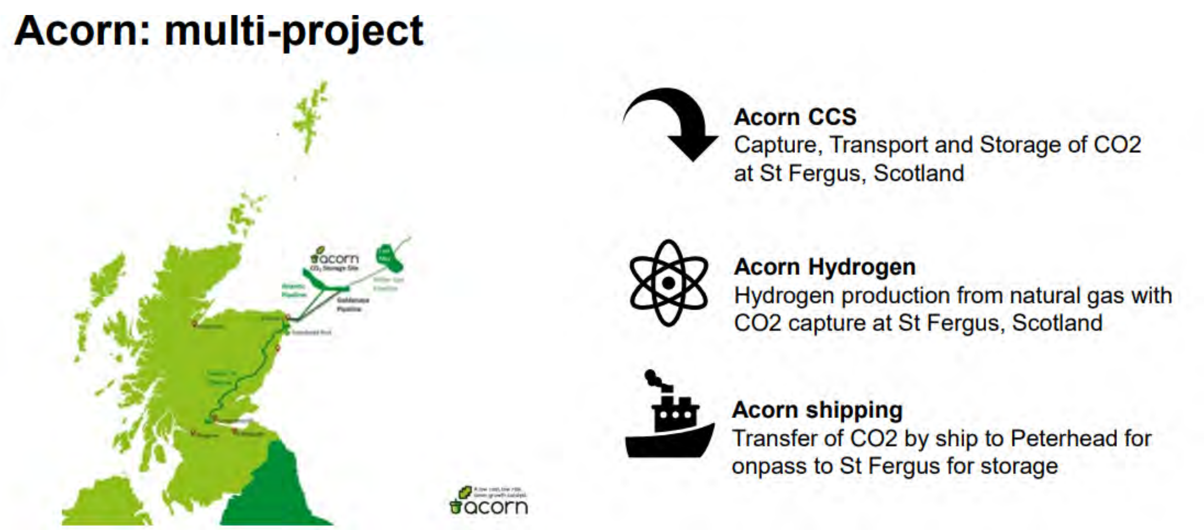
"Acorn is a full chain CCS project in north east Scotland. Being an infrastructure and storage resource led project, it is specifically designed to make best use of the UK's built and natural assets and initiate CCS in the UK. This is achieved through access to key offshore gas pipelines that are both available now and suitable for reuse for CO_2 transport.

In addition, around one third of the UKCS storage resource lies within this pipeline corridor including access to the world class, well understood and licensed Acorn CO_2 storage site.

The project will reuse the Golden Eye and Miller Pipelines leading to storage in the East Mey formation".

Source, Department for Business, Energy & Industrial Strategy, (BEIS, 2021).

Figure 27. Overview, Hydrogen from North Sea gas plan.



Source, UK CCS update & Acorn CCS project. (Pale Blue Dot, 2019)

Caledonia Clean Energy Project

This project will involve CCS-equipped natural gas power plant, CO_2 transportation and storage in the North Sea.

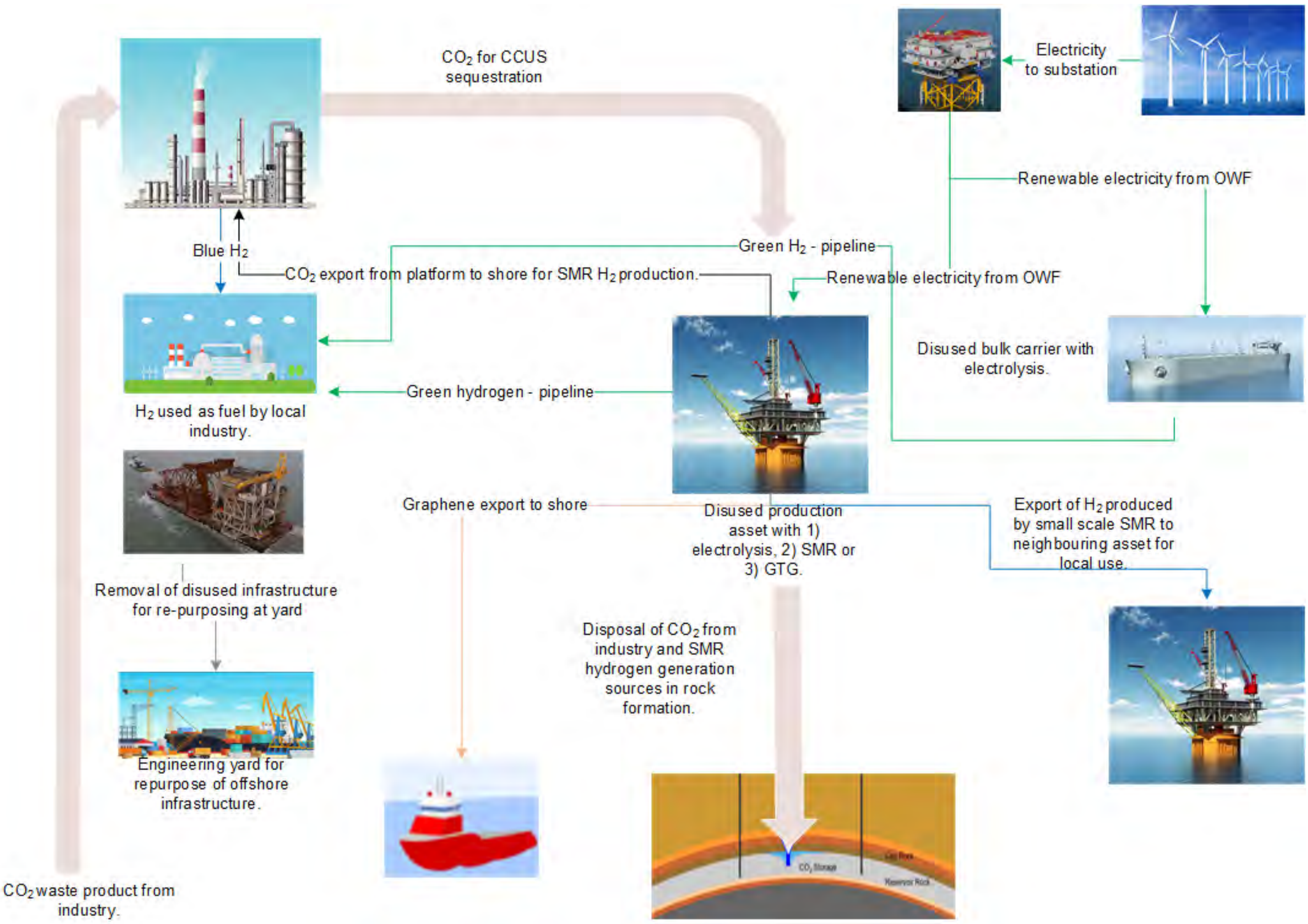
"95% of required pipelines for the project already exist and are suitable for repurposing at lower cost and lower risk than new build assets, representing a saving of up to £440 million in capital costs. A short new connection is required from Grangemouth to the Feeder 10 transport pipeline that runs to St. Fergus. The disused Atlantic & Cromarty pipeline runs from St. Fergus to the offshore injection location offering an ideal technical solution".

Source, Caledonia Clean Energy Project Feasibility Study Phase 2, Final Report. (Summit Power Caledonia UK Ltd, 2018).

5. Overview of development and consenting processes for commercial scale offshore green and blue hydrogen production

This section of the report is intended to present an overview of the development and consenting process that is considered relevant to commercial scale offshore green and blue hydrogen production in the UK. The overview considers the regulatory framework as it is cascaded from international agreements, national legislation and policy commitments to the role of key regulators, statutory consultees, permitting, licenses and consents (see Figure 28 and appendices for full size copy).

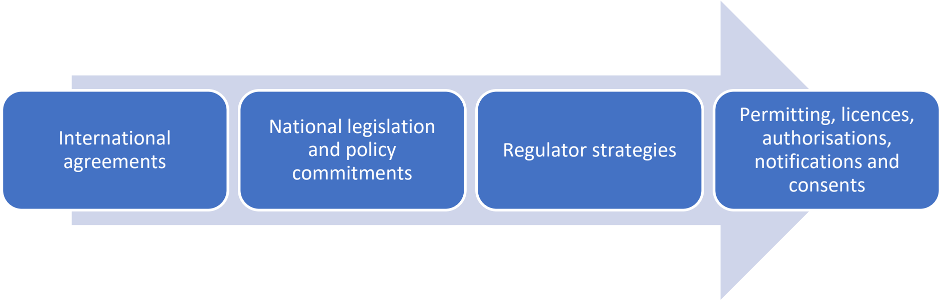
Figure 28. Scope of activities and actors associated with the repurpose of oil and gas infrastructure for the production of hydrogen subject to regulation.



5.1. The regulatory framework

The regulation of activities, assets and processes that support the repurpose of offshore infrastructure for the generation of commercial scale hydrogen must be regarded as part of a hierarchy of international conventions, protocols and agreements; national policy and domestic law.

Figure 29. Regulatory hierarchy



5.1.1. International agreements

The UK and Scottish Governments have agreed legally binding commitments to implement the Paris Agreement.

The Paris Agreement sets out a global framework to avoid dangerous climate change by limiting global warming to well below 2°C and pursuing efforts to limit it to 1.5°C.

5.1.2. National legislation and policy commitments

The Climate Change Act 2008 set in legislation the UK's approach to tackling and responding to climate change. It introduced the UK’s long-term legally binding 2050 target to reduce greenhouse gas emissions by at least 80% relative to 1990 levels. It also introduced ‘carbon budgets’ which cap emissions over successive 5-year periods and must be set 12 years in advance. In Scotland, the Scottish Government have established a policy to meet the objectives of the Paris Agreement by 2045.

The UK and Scottish government’s legally-binding commitment to net zero emissions by the agreed dates means there is a duty on everyone to act now and do everything possible to achieve this.

There is broad consensus that hydrogen will play a critical role in meeting carbon reduction objectives.

There is also a recognition that the oil and gas industry will be expected to play a key role in meeting our climate change targets by:

- reducing the carbon footprint from existing operations;
- helping solve the big challenges around hydrogen generation and associated carbon capture strategies.

5.2. Key regulators and statutory consultees

5.2.1. OGA

The Oil and Gas Authority’s role is to maximise the economic recovery of the UK’s oil and gas resources, whilst also supporting the move to net zero carbon by 2050.

The OGA has been given a range of powers under:

- The Petroleum Act 1998;
- The Energy Act 2016; and
- Energy Act 2011.

Source: (OGA, 2021)

The Oil and Gas Strategy (OGA) is the principal regulatory policy tool used by the UK government to maximise the economic recovery of UK oil and gas and support the UK government in its drive to reach net zero greenhouse gas emissions by 2050. A revised Strategy came into force on 11 February 2021. The revised OGA Strategy amends the MER UK Strategy.

Source: (OGA, 2021)

The revised Strategy places an obligation on the oil and gas industry to assist the Secretary of State in meeting the target of net zero carbon by 2050. The updated document features a range of new net zero obligations for the UK oil and gas industry, whilst retaining the MER strategy of the original document.

The revised Strategy reflects the ongoing global energy transition and the need to retain an energy mix for the foreseeable future as we transition to net zero. The Strategy requires industry to operate in a way consistent with net zero ambitions, lowering production emissions and making serious progress on the solutions that can contribute to the UK achieving net zero. This includes unlocking net zero solutions such as hydrogen production.

5.2.2. OSDR

The Offshore Safety Directive Regulator is the Competent Authority responsible for overseeing industry compliance with the EU Directive on the safety of offshore oil and gas operations.

OPRED and HSE act jointly as the Competent Authority on the safety of offshore oil and gas operations in the UKCS. This partnership implements Directive 2013/30/EU of the European Parliament and of the Council on the safety of offshore oil and gas operations and amending Directive 2004/35/EC.

Directive 2013/30/EU ("the Directive") is implemented in Great Britain and Northern Ireland by various legislation including in particular by the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015, similar regulations in Northern Ireland, and the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015.

The OSDR partnership regulates the adequacy of measures taken by those with legal duties to prevent, control and mitigate major safety and environmental hazards and their consequences. Acting in partnership, OPRED and HSE ensure compliance with the relevant UK and EU legislation that implements the Directive and its associated Implementing Regulation.

Cooperating on Other Mutual Regulatory Interests.

OPRED and HSE each have responsibilities to apply health and safety (HSE) and environmental (OPRED) statutory provisions separate to those made for the purpose of the Directive. Activities of relevance to the repurposing of offshore infrastructure include:

- Decommissioning;
- Pipelines;
- Reacting to Incidents and Emergencies;
- Sharing Regulatory Information;
- Development of Regulatory Policy and Technical Matters; and
- Legal Issues.

Source: (OSDR, 2020)

OPRED

OPRED is responsible for regulating environmental and decommissioning activity for offshore oil and gas operations in the UK.

Responsibilities include:

- handling domestic and international policy relating to the environmental regulatory framework for offshore oil and gas (working with other departments, environmental bodies and international organisations);
- developing, administering and enforcing the offshore oil and gas environmental regulatory regime (including offshore gas unloading and storage and carbon dioxide storage);
- implementing the oil and gas decommissioning regime and ensuring that the costs are met by the oil companies and not the taxpayer
- managing the department's Strategic Environmental Assessment for offshore energy projects.

Source: (OPRED, 2021)

HSE

HSE is responsible for ensuring that duty holders comply with their health and safety obligations with respect to decommissioning and dismantlement operations. HSE's considerations are therefore restricted to health and safety issues - based on the evidence in a safety case and PSR notifications. Receiving the draft Decommissioning Programme (DP) helps to inform HSE's dialogue with duty holders prior to them submitting the relevant safety case.

HSE's remit relates only to risks to people and not, for example, to economic or environmental issues. The HSE remit covers short term occupational risks to those employed in the decommissioning process and long term safety issues regarding wells and pipelines equipment which remain on location e.g. ensuring the safety of other users of the sea from the residual post-decommissioning hazards which remain in perpetuity.

Source: (HSE, 2021)

5.2.3. Marine Scotland

Marine Scotland is a directorate of the Scottish Government and is responsible for managing Scotland's seas for prosperity and environmental sustainability. This contributes to the Scottish Government's overall purpose of sustainable economic growth and the achievement of a shared vision of clean, healthy, safe, productive, biologically diverse marine and coastal environments, managed to meet the long term needs of people and nature.

Under the Marine Scotland Act 2010 the Scottish Ministers are responsible for marine licensing and enforcement in the Scottish inshore region (out to 12 NM). This includes the waters of every estuary, river or channel, so far as the tide flows at mean high water spring tide. Under the Marine and Coastal Access Act 2009 Scottish Ministers also have responsibility for licensing and enforcement in the Scottish offshore region (12-200 NM).

In addition, consent from Scottish Ministers under s.36 of the Electricity Act 1989 is also required for generating stations above 1 megawatt (MW) capacity in Scottish inshore region and above 50 MW in the Scottish offshore region.

MS-LOT, a team within Marine Scotland, is the regulator responsible for the impartial assessment of Marine licence and s.36 consent applications, ensuring compliance with all relevant legislation and the issue of all marine related permissions. It operates a “one stop shop” to handle the entire consenting/licensing process, from initial queries through to the issuing of permissions and post-consent approvals. It is the single point of contact for all queries relating to the licensing of the deployment of offshore renewable energy devices in Scottish waters.

The following are the consents and approvals for which the Scottish Ministers are the competent or regulatory authority:

- Marine Licences under Part 4 of the Marine (Scotland) Act 2010 and Part 4 of the Marine and Coastal Access Act 2009;
- Consent under S.36 of the Electricity Act 1989;
- EPS licenses under the Conservation (Natural Habitats, &c.) Regulations 1994 (as amended) and the OMRs 2017;
- Basking Shark Licences under the Wildlife and Countryside Act 1981 (as amended) and the Wildlife and Natural Environment (Scotland) Act 2011);
- Safety Zone applications (Energy Act 2004, as amended by the Scotland Act 2016); and
- Decommissioning programmes (Energy Act 2004, as amended by the Scotland Act 2016).

5.2.4. Crown Estate Scotland

In Scotland, the foreshore and seabed out to a distance of 12 NM are presumed to belong to The Crown, with management of this resource being the responsibility of Crown Estate Scotland. Applicants need to obtain a lease from Crown Estate Scotland (or the holder of the rights) for the use of all sea areas in inshore waters (up to 12 NM) or out to 200 NM in Scottish offshore waters.

5.2.5. Statutory Consultees

There are four main statutory consultees for s.36 applications (under the Electricity Works (Environmental Impact Assessment) (Scotland) Regulations 2017): the planning authority/ies, Scottish Natural Heritage (“SNH”); Scottish Environment Protection Agency (“SEPA”); Historic Environment Scotland; and where required, any EEA State identified as being significantly affected by the development.

Statutory consultees for Marine Licence (ML) applications (under the Marine Works (Environmental Impact Assessment) (Scotland) Regulations 2017) are any relevant local planning authority, SNH, SEPA, Historic Environment Scotland, and any relevant authority. Additional statutory consultees under the Marine Licensing (Consultees) (Scotland) Order 2011 are the Commissioners of Northern Lighthouses, the Maritime and Coastguard Agency (MCA) and any delegate for a region.

Scottish Natural Heritage (SNH)

SNH is Scottish Ministers’ independent statutory advisors on nature conservation in Scottish inshore waters and also now has delegated responsibility for providing advice on renewable energy applications in Scottish Offshore Waters.

Planning Authorities

Planning Authorities are statutory consultees for s.36 applications and are also fully consulted on any deemed planning components of a s.36 application.

Maritime and Coastguard Agency

The MCA is a statutory consultee for MLs and has responsibility for ensuring the navigational safety of the marine environment.

Northern Lighthouse Board

The Northern Lighthouse Board is a statutory consultee for MLs and is responsible for advising on all buoys, lights, or other marking requirements and for issuing Statutory Sanction to deploy such markers.

Marine Planning Partnerships

Regional marine planning will be undertaken by Marine Planning Partnerships, which will be made up of marine stakeholders who reflect marine interests in their region.

Marine Renewables Facilitators Group

To assist in tackling complex issues and/or to resolve areas of dispute any time in the application process, MS-LOT may decide to bring together an advisory group, the Marine Renewables Facilitators Group (MRFG).

Scottish Environment Protection Agency

As a non-departmental public body of the Scottish Government, the role of SEPA is to make sure that the environment and human health are protected, to ensure that Scotland's natural resources and services are used as sustainably as possible and contribute to sustainable economic growth.

The Scottish Environment Protection Agency (SEPA) is a statutory consultee for both s.36 and MLs and is Scotland's environmental regulator whose main role is to protect the environment. The two primary regulatory mechanisms for SEPA, in relation to offshore energy, are:

- Water Environment and Water Services Act 2003;
- Water Environment (Controlled Activities) (Scotland) Regulations 2011 (applicable out to 3 NM).

Onshore, SEPA is responsible for enforcing regulations associated with:

- activities that may pollute water;
- activities that may pollute air;
- waste storage, transport, treatment and disposal;
- the management of radioactive substances;
- activities that may contaminate land;
- activities associated with radioactive substances.

Where activities carried out by business or industry can, potentially, be harmful to environment you will need a license or other authorisation. Such activities are likely to include:

- waste management and decommissioning activities associated with the physical repurposing of offshore infrastructure;
- the operation of a high risk PPC Part A industrial activity such as power generation;
- the operation of a PPC Part B process which focusses on the control of emissions to air,
- operations which involve radioactive substances such as NORM (naturally occurring radioactive material), LSA (Low Specific Activity) scale and other sources associated with the repurposing of offshore infrastructure.

Source: (SEPA, 2021)

5.3. Permits, licences and consents.

This section is intended to provide developers, operators and contractors with an overview of the permitting and authorisation timeline for activities regulated by the OGA, OSDR and Marine Scotland.

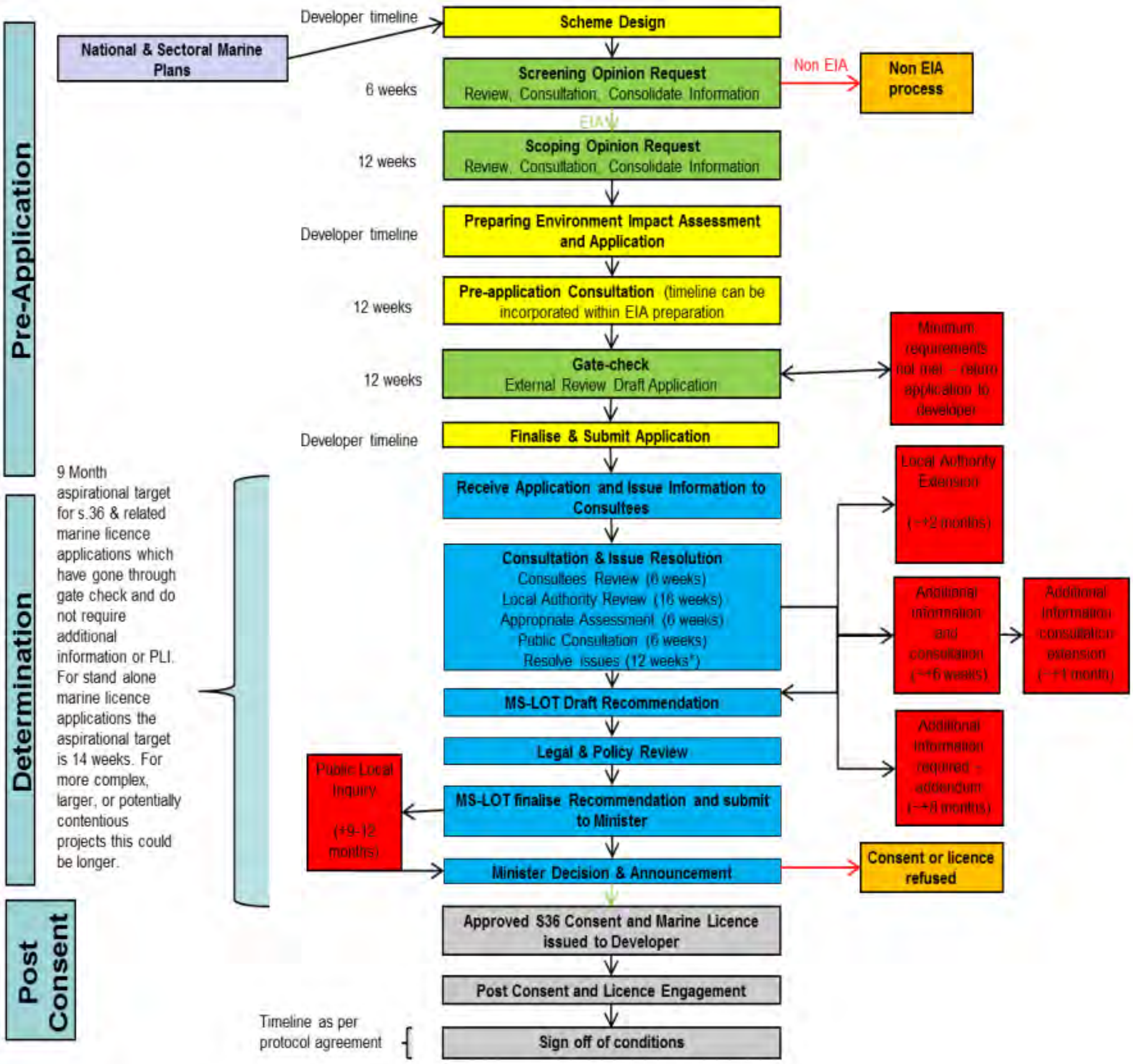
The timeline for processing of permits, licenses and consents relevant to the repurposing of existing oil and gas infrastructure for offshore hydrogen production will depend on the complexity of the activity being considered.

5.3.1. Timeline - Marine Scotland

Activities that require a licence or authorisation are defined within the Marine Act.

Indicative timescales for the consenting and licensing process that are associated with Offshore Wind, Wave and Tidal Energy Applications renewables regulated by Marine Scotland are presented in the Figure 30 below.

Figure 30. Consenting and licensing process timeline. Source: (Marine Scotland, Consenting and Licensing Guidance (offshore wind, wave and tidal energy), 2018).



The Marine Acts make it an offence to carry on, or cause or permit another person to carry on, a ‘licensable marine activity’ without a Marine Licence. It is a licensable marine activity’ to do any of the following in Scottish Waters (from Mean High Water Springs out to 12 NM under the Marine (Scotland) Act 2010 and 12-200 NM through devolved powers in accordance with the Marine and Coastal Access Act 2009):

- Deposit any substance or object in the sea or on or under the seabed;
- Deposit any substance or object in the sea or on or under the seabed from a vehicle, vessel, aircraft or marine structure loaded with the substance or object in Scotland or in the Scottish Waters;
- Construct, alter or improve works on or over the sea or on or under the seabed from a vehicle, vessel, aircraft or marine structure;
- Remove substances or objects from the seabed;
- Dredging (including plough, agitation, side-casting and water injection dredging);
- Deposit and/or use explosives; and
- Incinerate substances or objects.

Source: (Marine Scotland, 2021)

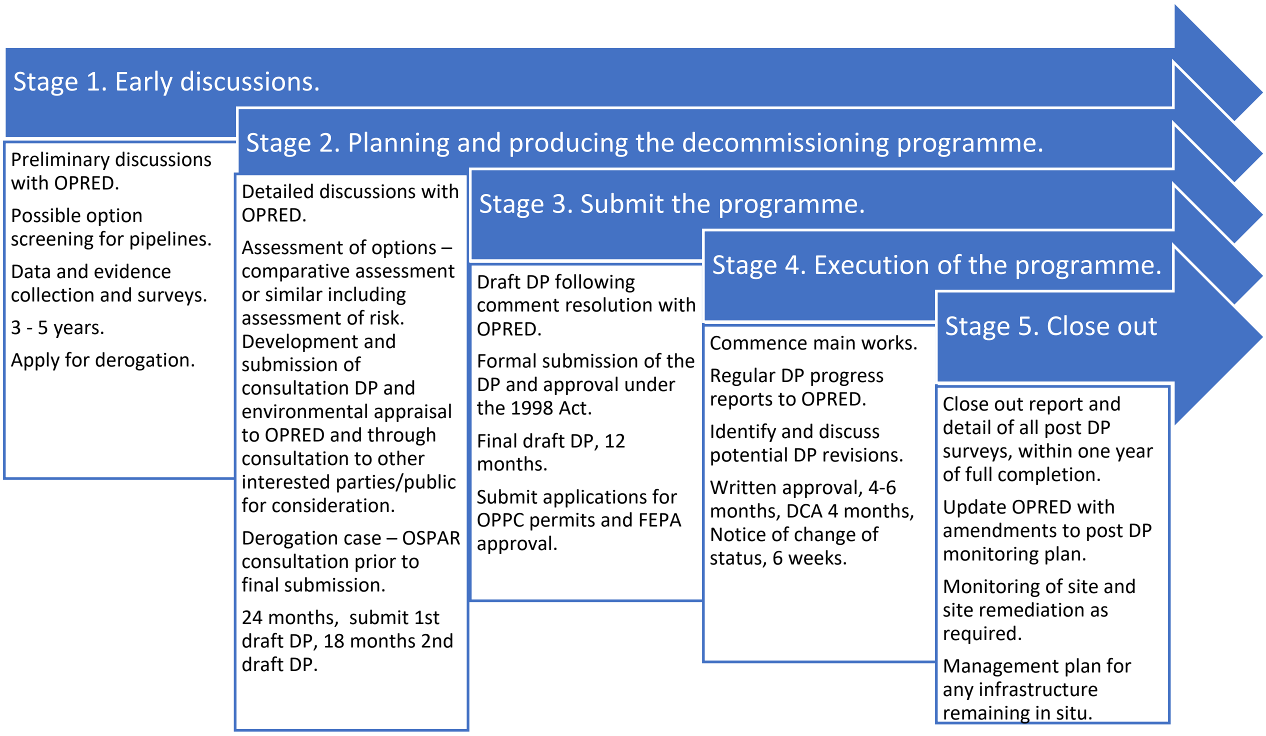
5.3.2. Timeline – OSDR / OPRED

The timeline for processing of permits, licenses and consents associated with the full or partial decommissioning of an offshore installation for the repurposing of existing offshore infrastructure, follows a staged process.

Operators are required to submit their Decommissioning Programme (DP) to OPRED for approval to start the decommissioning process. Decommissioning of installations generally commences at cessation of production (CoP), however planning for decommissioning begins at least two years prior to CoP with OPRED and other agencies consulted throughout the process. SEPA is consulted prior to and throughout the life of the DP.

The five stage process starts before CoP and continues through the early identification of options, to detailed assessment and drafting of a DP, followed by execution and then post completion activity. The stages are detailed below.

Figure 31. Indicative timeline for decommissioning programme.



Adapted from the SEPA Oil and Gas Decommissioning Sector Plan (SEPA, 2021) and OGUK, Decommissioning – Consent Requirements: (OGUK, 2021)

5.3.3. Timeline - HSE

The timeline for preparation of a decommissioning safety case or PSR (pipeline safety notification) starts with the preparation of a draft DP. This arrangement reflects the working arrangement between OPRED and the HSE as OSDR.

Given the substantial nature of the proposed operations for the larger installations, the HSE find it helpful for the duty holder and HSE to work closely together during the development of the decommissioning programme, so that any concerns about the proposed conduct of the operations can be identified and resolved in good time. Ideally this will be before any significant decisions have been taken and before substantial expenditure has been committed to.

Safety Case

HSE consider duty holder arrangements with respect to decommissioning and dismantlement operations as part of the OPRED decommissioning approval process. Receiving the draft DP helps to inform HSE's dialogue with duty holders prior to them submitting the relevant safety case.

Regardless of the DP adopted, in undertaking the proposed work, the duty holder is required to comply with all relevant regulations providing for the health and safety of persons. In particular, a key requirement is to reduce, so far as reasonably practicable, the risks to persons from work activities. Control of such risks will need to be described in the safety case notification, which is subject to acceptance by HSE before work may proceed.

PSR Notification

Regulation 22(2) of the Pipelines Safety Regulations requires at least three months notification prior to commencement of works. Regulation 22 concerns significant changes to the pipeline which can affect the level of risk. Examples which are relevant to the repurposing of offshore infrastructure for the production of hydrogen include:

- Major modifications/remedial work to the pipeline.
- Changes in safe operating limits e.g. when changing from one pressure to another.
- Changes in fluid composition or type. Pipelines may be designed to operate with dry gas but changes to the status of offshore installations may only be achieved if the gas can be transported in a wet state - this may have a significant effect on the integrity of those pipelines and downstream facilities.
- End of use of a pipeline. This notification should set out the steps to be taken to decommission, dismantle or "abandon" a pipeline. It is envisaged that a notification will comprise a timetable indicating when the pipeline is to be taken out of service, how long the line was to remain decommissioned and a description of how the line is to be made permanently safe.
- Changes in pipeline materials and equipment. This may comprise no more than a map or chart showing where the changes are to take place and a brief description of the material and/or dimensional changes.
- Re-routing of pipelines e.g. in close proximity to offshore installations which could have an effect on the safety of the installation.
- Re-routing of pipeline risers on offshore installation which may then pass closer to living quarters or other vulnerable areas.
- The repositioning of Emergency Shut Down Valves (ESDVs) on pipeline risers.

Source: (HSE, 2021)

5.3.4. Other major licensing and scheduling considerations

Other issues to be considered when planning for the repurpose of an existing offshore installation for hydrogen include:

- Requirements for engineering and recycling yards to comply with the necessary permits and authorisations to carry out repurposing works in accordance with regulations specified under the Health and Safety at Work Act, 1974 and the Environmental Protection Act, 1990 Act. For a yard to be in a position to carry out the works, it must hold the necessary permits, licences and consents. As a guide, permitting of a waste recycling facility can take up to 18 months to prepare and process the necessary permit applications and licences required to operate the facility.
- Requirements under the Supply of Machinery (Safety) Regulations 2008, as amended, and associated regulations should be anticipated for equipment such as electrical sub stations for supply of electricity from offshore wind farms for platform electrification purposes.
- Requirements to comply with The Construction (Design and Management) Regulations 2015 which apply on shore and offshore to the construction and decommissioning of installations not covered by the Safety Case and PSR regimes. Requirements to comply with MCA obligations associated with the use of a vessel, either as a host for hydrogen generation, or as a service provider.
- Requirements to comply with and MCA obligations associated with the use of a vessel, either as a host for hydrogen generation, or as a service provider.

- Requirements to comply with Marine Classification obligations. Marine Classification is concerned with promoting the safety of life, property and the environment primarily through the establishment and verification of compliance with technical and engineering standards for the design, construction and life-cycle maintenance of ships, offshore units and other marine-related facilities.
- Requirement to comply with The Energy Act 2008 (the Act) which provides for a licensing regime that governs the offshore storage of carbon dioxide. The Act forms part of the transposition into UK law of EU Directive 2009/31/EC on the geological storage of carbon dioxide. The Carbon Dioxide (Licensing etc.) Regulations 2010 (SI 2010/2221), which transpose many other requirements of the directive, came into force on 1 October 2010.

5.3.5. Codes and standards

Codes and standards which have been identified as being relevant to hydrogen by various means, including electrolysis and steam methane reforming processes are presented in **Appendix H.**

6. Overview of availability and suitability of electrolyser technologies for offshore hydrogen production

This section of the report is intended to provide an overview of electrolyser technologies, most suited for offshore hydrogen production.

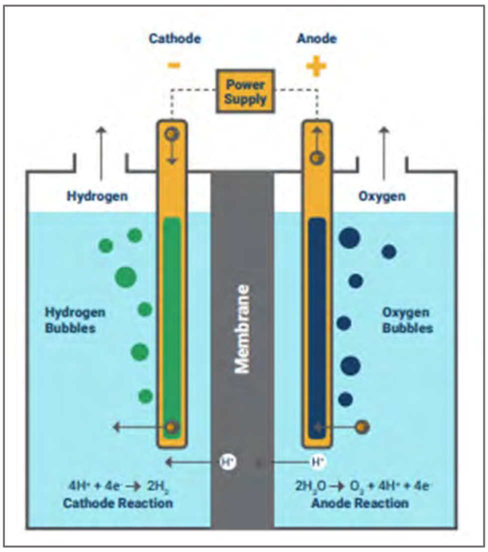
The focus of the assessment is the availability and suitability of the technology in a re-purposing scenario.

In conducting this review, the assessment considered the status of existing technologies and the global application of electrolyser units.

6.1. Availability of existing electrolysis technologies

Electrolysis is a well-established and well-known process of producing Hydrogen from water in an electrolyser unit.

Figure 32. Electrolysis Process. Source (OGTC, 2020), Closing the gap.



The reaction in the unit takes place in the presence of an electric charge (e^-) where it is used to split water into hydrogen and oxygen, according to the formula:

- $2\ H_2O \rightarrow 2\ H_2 + O_2$

There are several main types of electrolysers, at differing levels of commercialisation:

- Alkaline (AEL);
- Proton Exchange Membrane (PEM) also known as polymer electrolyte membrane; and
- Solid Oxide Electrolyser Cell (SOEC)

6.1.1. Alkaline Electrolysers (AEL)

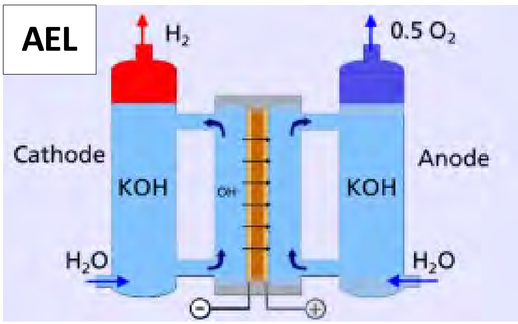
Alkaline electrolysers represent the oldest and currently most established technology for the electrolysis of water. Alkaline electrolysers operate via transport of hydroxide ions (OH^-) through the electrolyte from the cathode to the anode with hydrogen being generated on the cathode side. Electrolysers using a liquid alkaline solution of sodium or potassium hydroxide as the electrolyte have been commercially available for many years.

Figure 33. AEL Key characteristics.

Technology	Temp range	Cathodic Reaction (HER)	Charge Carrier	Anodic Reaction (OER)
Alkaline electrolysis	40 - 90 °C	$2H_2O + 2e^- \rightarrow H_2 + 2OH^-$	OH^-	$2OH \rightarrow ½\ O_2 + H_2O + 2e^-$

Newer approaches using solid alkaline exchange membranes as the electrolyte are showing promise on the lab scale.

Figure 34. Representation of the Alkaline electrolysis process. Source: (Fraunhofer-Institut für Solare Energiesysteme ISE, 2014).



- The Sunfire-Hylink Alkaline Electrolyser data forms the basis for metrics evaluation.

6.1.2. Proton Exchange Membrane (PEM)

In a proton exchange membrane (PEM) electrolyser, the electrolyte is a solid specialty plastic material.

Water reacts at the anode to form oxygen and positively charged hydrogen ions (protons).

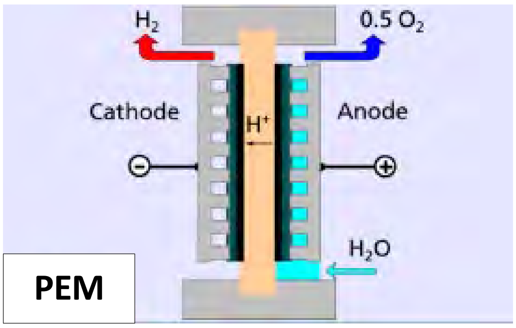
The electrons flow through an external circuit and the hydrogen ions selectively move across the PEM to the cathode.

At the cathode, hydrogen ions combine with electrons from the external circuit to form hydrogen gas.

Figure 35. PEM Key characteristics.

Technology	Temp range	Cathodic Reaction (HER)	Charge Carrier	Anodic Reaction (OER)
Membrane electrolysis	20 - 100 °C	$2H^+ + 2e^- \rightarrow H_2$	H^+	$H_2O \rightarrow ½\ O_2 + 2H^+ + 2e^-$

Figure 36. Representation of the PEM process. Source: (Fraunhofer-Institut für Solare Energiesysteme ISE, 2014).



- The ITM Power HGAS3SP electrolyser data forms the basis for metrics evaluation.
- The Siemens Silyzer 300 is the reference point concerning weight (Kg/ MW H_2) and CAPEX (£/ MW).)

6.1.3. Solid Oxide Electrolyser Cell (SOEC)

A Solid Oxide Electrolysis Cell (SOEC) is a solid oxide fuel cell that runs in regenerative mode to achieve the electrolysis of water (and/or carbon dioxide) by using a solid oxide, or ceramic, electrolyte to produce hydrogen gas (and/or carbon monoxide) and oxygen. SOECs operate at relatively high temperatures (700-1000 °C), which makes the efficiency very high.

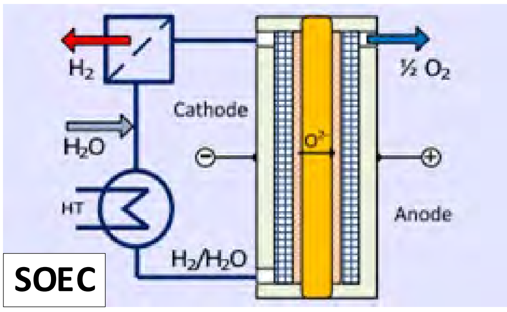
The two electrolysis products, hydrogen and oxygen, are formed on each side of the cell. SOECs may be used for the production of hydrogen from surplus electricity generated by, e.g., wind turbines. The hydrogen can be stored and – using a fuel cell – reconverted into electricity again when the demand arises. This allows the storage of electricity when production exceeds demand.

Source: (DTU Energy, 2019)

Figure 37. SOEC Key characteristics.

Technology	Temp range	Cathodic Reaction (HER)	Charge Carrier	Anodic Reaction (OER)
High temp. Electrolysis (SOEC)	700 - 1000 °C	$H_2O + 2e^- \rightarrow H_2 + O^{2-}$	O^2	$O2- \rightarrow ½ O_2 + 2e^-$

Figure 38. Representation of the SOEC (HT) process. Source: (Fraunhofer-Institut für Solare Energiesysteme ISE, 2014).



- The Sunfire-Synlink SOEC Electrolyser data forms basis of metrics evaluation.

6.2. Global application of electrolyser technologies in an offshore environment

The number of projects using electrolyser technology continues to grow with the intensifying focus on emissions reductions for countries across the globe. An example of some high profile projects, some of which were considered in this study are presented here.

Figure 39. A sample of global electrolyser projects. Source: (JRC Science Hub, 2019)

Project	Location	Onshore/ Offshore	Electrolyser Type	Capacity	Electrical Supply
PosHYdon Pilot (Q13-a Platform)	Netherlands, EU	Offshore	PEM	1 MW (Single Stack)	From shore, simulation of offshore wind fluctuations for pilot
BIG HIT	Orkney Islands, UK	Onshore	PEM	1.5 MW (1 MW and 0.5 MW)	Constrained Renewable
H2Future	Austria, EU	Onshore	PEM	6 MW (3 x 2MW units)	Renewable; supplemented by grid
HYBALANCE	Denmark, EU	Onshore	PEM	1.25 MW	Renewable
REFHYNE	Germany, EU	Onshore	PEM	10 MW (5 x 2MW units)	Renewable; supplemented by grid
Energiepark Mainz	Germany, EU	Onshore	PEM	6 MW (3 x 2MW units)	Renewable; supplemented by grid
MULTIPLHY	Netherlands, EU	Onshore	SOEC	2.6 MW	Renewable
GRINHY	Germany, EU	Onshore	SOEC	150 KW	Renewable
GRINHY2.0	Germany, EU	Onshore	SOEC	720 KW	Renewable
DEMO4GRID	Austria, EU	Onshore	AE	3.2 MW	Renewable

6.3. Suitability of electrolysis for the generation of hydrogen associated with repurposed oil and gas infrastructure

This element of the report considers the suitability of electrolysis technology to generate hydrogen. In this context, the suitability evaluation of available technology takes account of a number of key metrics relevant to the use of repurposed infrastructure for the offshore production of hydrogen.

Figure 40. Comparison of electrolysis technologies against key metrics (Adapted from (www.fch.europa.eu) electrolysis in the EU).

	Alkaline	PEM	SOEC
Benchmark	Sunfire-Hylink Alkaline Electrolyser	ITM Power HGAS3SP; Siemens Silyzer 300	Sunfire-Hylink SOEC
Tech Maturity and commercial availability	Mature, wide use across industry for the last century.	Commercial technology with increasing application.	Emerging technology but is commercially available.
Availability and reliability (Source: Fraunhofer ISE)	Older systems have excellent lifetime in steady state operation > 100,000 h / 9-15 years. Newer concepts: 50-70,000 h	Comparable to AEL if well designed. But mostly < 40,000 h / 5-10 yrs. Degradation mechanism not fully understood.	Few 1,000 h with decay rate < 1%/1000 h. But considerable progress in the last years: 40,000 h should be feasible (cell level). Thermal management is essential for dynamic operation and lifetime.
Safety	Comparable	Comparable	Comparable
Electrolyte	Potassium-hydroxide	Solid state membrane	Oxide Ceramic
Size (M^2/ MW H_2)	~ 70	~ 25	~ 100
Weight (Kg/ MW H_2)	~ 21	~ 15	~25
Hydrogen production Efficiency	65% - 82%	65% - 78%	80% - 90%
H_2 Purity	99.50% - 99.9999%	99.9% - 99.9999%	99.9% - 99.9999%
H2 Production (Nm^3 H_2 / Hr)	< 1,100	< 240	< 750
Discharge Pressure	Low; 30 barg	Up to 200 barg	Low; 25 barg
Operating Temp (DegC)	60 - 90	50 - 80	850 - 1,000
Water Consumption	~ 300	~ 300	860 kg / hour (Steam)
CAPEX £ / MW	0.3MM – 0.8MM	0.4MM - 1.1MM	1.0MM – 2.0MM
Offshore Infrastructure Repurposing Application.	Footprint and weight limit potential use for offshore infrastructure. Live pilot projects repurposing ageing infrastructure are using 1MW capacity electrolysers. Higher capacity units will present weight and footprint issues for existing infrastructure as well as issues relating to platform lift capacity. Candidate infrastructure would have to be assessed on an individual basis to ascertain capacity.		
Note: Nm^3 = normal cubic metres			

Adapted from (www.fch.europa.eu) electrolysis in the EU.

6.4. Electrolysis and desalination

Electrolysis is the process for producing hydrogen, but the water supply is a key enabler to the process. When considering the use of seawater (which is the water source for the assessment within this study), there are unique challenges from the salt content which can cause corrosion and form chlorine and other gases during the process. Seawater electrolysis therefore requires desalination technology.

The innovation gap for cost-effective integrated desalination or direct seawater electrolysis is critical and unlikely to be resolved without significant effort. Seawater desalination technology development as an element of the overall hydrogen technology roadmap is a critical path activity, with an indicative timeline for development landing in 2035.

Source: (OGTC, 2020), Closing the Gap.

6.5. Infrastructure repurposing potential for electrolysers

This study builds on the findings of an earlier study conducted by Lloyd's Register – Energy, (now Vysus Group) in 2019 which considered the potential for retrofitting electrolysers offshore.

The main technical challenges drawn from this earlier study for the re-purposing of offshore infrastructure for hydrogen production were identified:

- The footprint of available technology (and associated equipment);
- The weight of available technology (and associated equipment).

The observations of this earlier study continue to be pertinent in 2021 despite an evolving electrolyser technology market.

Depending on electrolyser capacity there may be a requirement for a complete rebuild of the platform offshore, i.e. removing all the existing equipment to create space, structural reinforcement as required and new equipment installation.

Some relevant projects are summarised below.

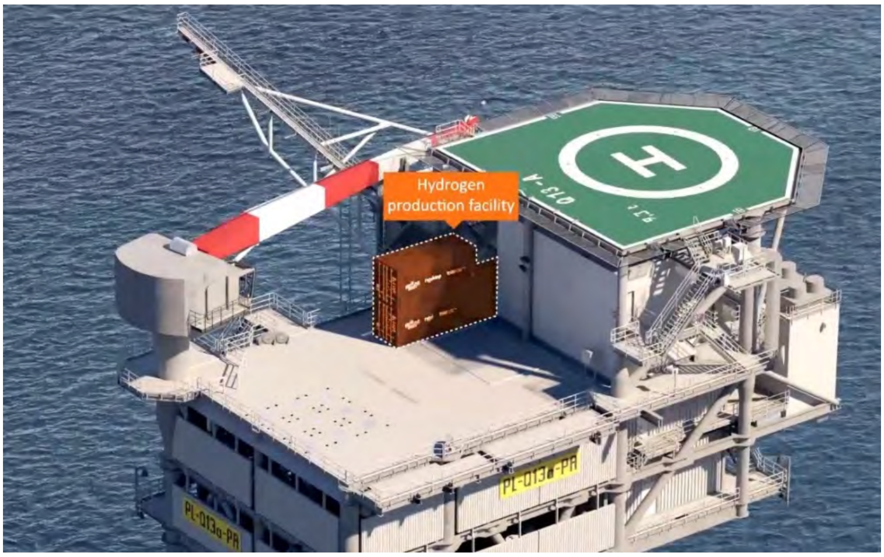
The PosHYdon Pilot (Q13-a Platform)

The PosHYdon Pilot (Q13-a Platform) project is the world's first offshore green hydrogen project utilising existing infrastructure. The Q13-a platform operated by Neptune Energy is located 13km offshore Netherlands. The containerised unit consists of single stack 1 MW PEM electrolyser and desalination unit with a footprint of 40ft.

The platform is fully electrified from onshore renewable energy which makes it an ideal candidate for this pilot project. The produced hydrogen is blended into the existing gas export pipeline.

[Source: (Neptune Energy PosHYdon Pilot, 2019)

Figure 41. Q13-a Platform with containerised PEM electrolyser. Source: (Durakovic, 2019).



The project will undoubtedly increase knowledge of green hydrogen production on existing offshore infrastructure and encourage and focus technology innovation. This pilot project may provide the blueprint for similar projects within the Scottish EEZ. It should be noted however that the project is relatively close to shore and the electrolyser is of modest capacity.

Markham and Brent Delta

The OGTC HS413 – Phase 1 Project Report outlines potential for larger scale electrolysis on existing infrastructure within the UKCS. The concepts are for PEM electrolysers to be installed on the Markham (SNS, 160km offshore) and Brent Delta assets (NNS, 186km offshore, decommissioning programme underway).

These are indicative concepts, but the layout drawing of the Markham concept does highlight the potential for asset repurposing with electrolysis. Interestingly the report also highlights the high number of assets which would be required to produce hydrogen at the same rate as a typical onshore SMR plant (BEIS Counterfactual). This could be taken as a high level indicator that offshore electrolysis is an element of an emerging hydrogen economy but is likely to be a complementary element in comparison to large capacity onshore hydrogen production infrastructure.

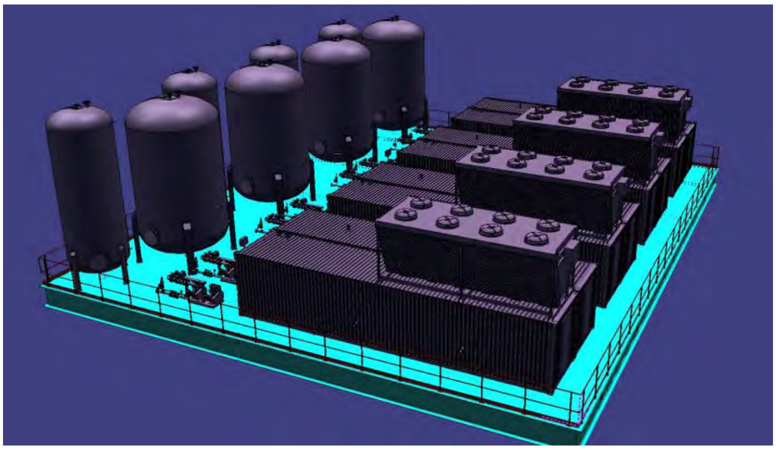
The BEIS counterfactual is a conventional Steam Methane Reformer (SMR) designed for a capacity of 100,000 Nm³/h, with post-combustion carbon capture on the reformer flue gas using a proprietary amine solvent.

Figure 42. Number of Assets to Meet BEIS Counterfactual [source; (OGTC (Phase 1 project report, HS413), 2019).

PEM Electrolysers		Markham	Brent Delta
	No per Asset	4	22
	Kg H_2 / Asset / Day	3,568	19,626
	MWth	5.0	27.3
	No Assets to Meet BEIS Counterfactual	61	11

Note: This study did not consider the transportation or storage of hydrogen.

Figure 43. Markham Layout with PEM.



7. Overview of cost estimation for key enabling Hydrogen Supply Chain capability and infrastructure

This section of the report is intended to provide an overview and cost estimate for key enabling hydrogen supply chain capabilities and infrastructure for repurposing scenarios identified during the scoping phase of this study.

The scope of the study considered available data for existing offshore oil and gas infrastructure, electrolyser supply, port and quayside infrastructure, reinforced quayside areas (with services), operation and maintenance marine and quayside operations.

7.1. Boundaries

It is important to note that work to date did not cover:

- Economic assessment of hydrogen production, transportation & storage concepts.
- Synergies with other offshore integration opportunities such as CCS and platform electrification.

The costing methodology, key findings and recommendations for further study are outlined in subsequent sections.

7.2. Assumptions

Assumptions underpinning the cost estimate for each repurposing scenario are presented in Appendix I.

7.3. Methodology

Costing accuracy is at Class 4 level. Expected accuracy is in the range of Low -15% to -30% and High +20% to +50%. Class 4 is suitable for a feasibility study with a low level of maturity and project definition, providing indicative costs for the purposes of a high-level scoping exercise. This class of costing is consistent with previous energy transition studies delivered by Vysus Group at a study or feasibility level.

Figure 44. Cost Estimate Class

	Primary Characteristic	***Secondary Characteristic***		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

(from AACEI Recommended Practice 18R-97 – Table 1)

In order to develop the scoping cost estimates for each of the scenarios (Section 4.1.2) an MS Excel cost model was assembled to:

- provide a flexible means of costing a range of hydrogen scenarios;
- allow for different hydrogen architectures to be assessed; and
- allow comparison of cost and cost metrics between scenarios.

Costs are derived from publicly available resources with verification provided by in-house figures developed by Vysus using Que$tor software.

Output costs are shown on a cost per kg hydrogen produced basis (£/ kg H_2). These are presented, as excluding and including electricity and gas (if applicable to scenario).

Figure 45. Cost types included within model:

CAPEX (£/kg H_2)	OPEX (£/kg H_2)	ABEX (DECOMM) (£/kg H_2)	Electricity Consumption (£/kg H_2)	Gas Consumption (£/kg H_2)

A detailed description of the cost model configuration and cost block is provided in Appendix J.

7.4. Results of the analysis

Cost estimates for scenarios studied in the comparative assessment are presented in Figures 46 and 47.

Figure 46. Scenario Cost Estimates – Base Case (Industry 'Very Large' Consumer of Electricity).

Scenario	CAPEX (£/kg H_2)	OPEX (£/kg H_2)	ABEX (£/kg H_2)	Cost of H_2 (ex. Power) (£/kg H_2)	Electricity (£/kg H_2)	Gas (£/kg H_2)	Cost of H_2 (incl Power) (£/kg H_2)
1	2.42	2.48	0.15	5.05	7.20	n/a	12.25
2a	2.59	2.56	0.15	5.30	7.20	n/a	12.49
2b	1.69	2.01	0.18	3.88	0.02	1.61	5.51
2c	*Further work required to develop for cost comparison*						
4b	1.45	1.82	0.18	3.45	0.02	1.61	5.07
4c	*Further work required to develop for cost comparison*						

Figure 47.Cost Estimates – Wholesale Electricity Price – Scenarios 1 and 2a

Scenario	CAPEX (£/kg H_2)	OPEX (£/kg H_2)	ABEX (£/kg H_2)	Cost of H_2 (ex. Power) (£/kg H_2)	Electricity (£/kg H_2)	Gas (£/kg H_2)	Cost of H_2 (incl Power) (£/kg H_2)
1	2.42	2.48	0.15	5.05	3.10	n/a	8.16
2a	2.59	2.56	0.15	5.30	3.10	n/a	8.40

Figure 48 shows the results of the comparative analysis as the sum cost per kg hydrogen produced.

Figure 48. Base Case Scenario Cost £/kg Hydrogen Production Chart.

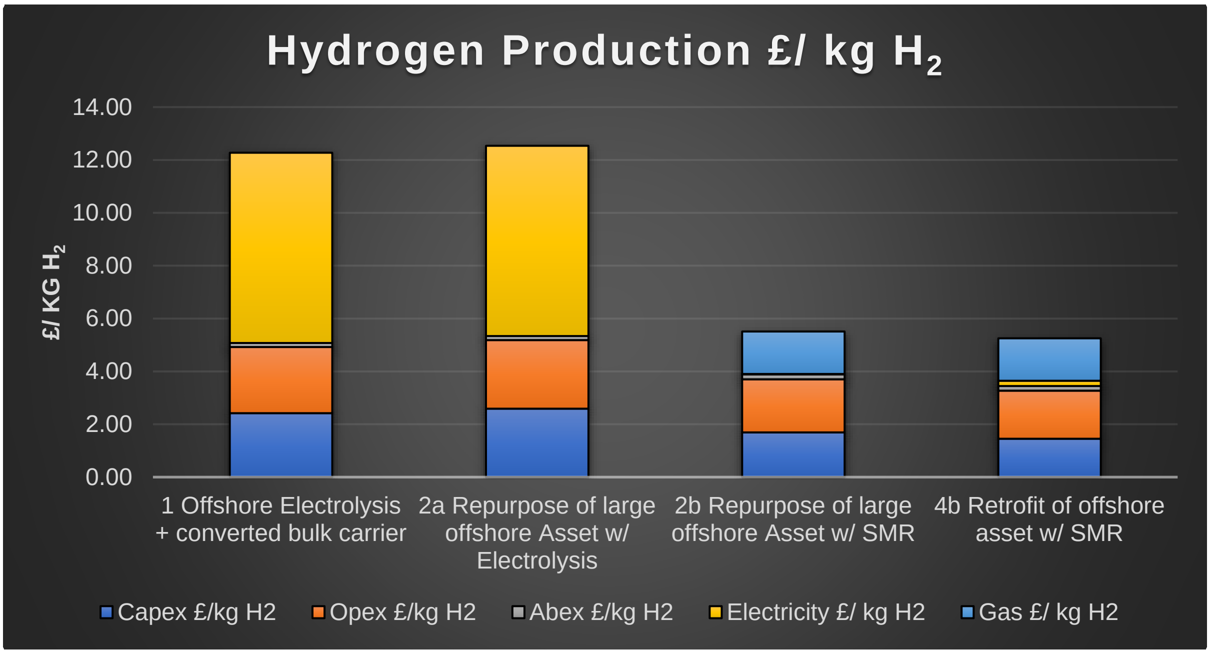
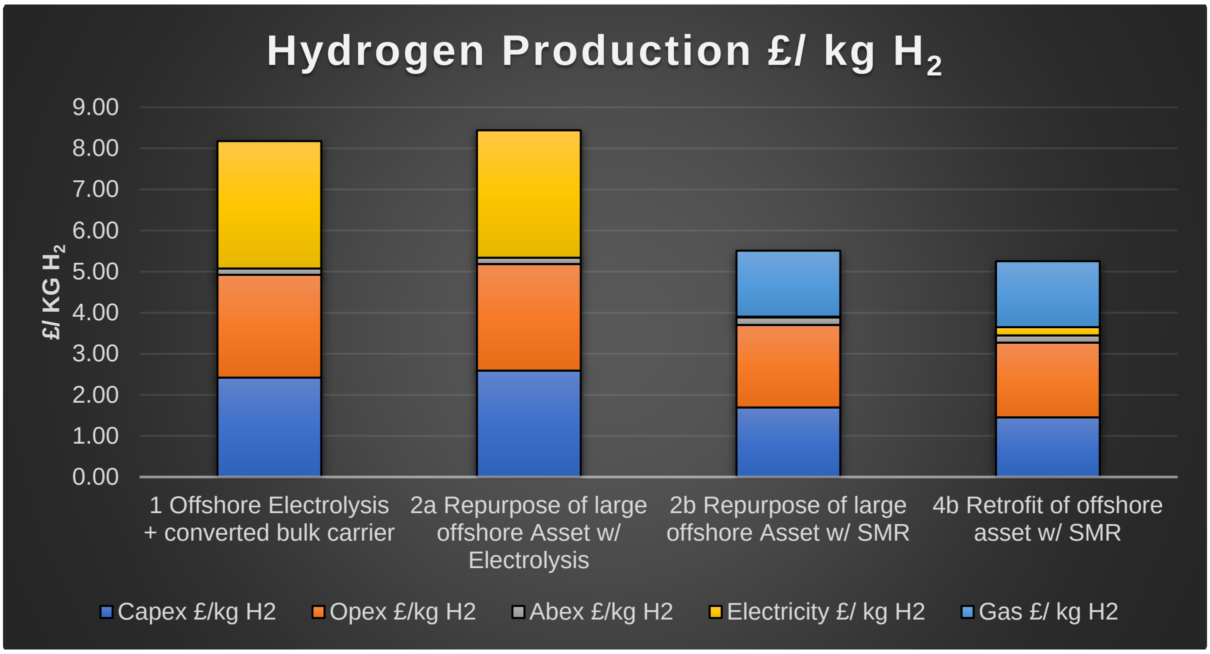


Figure 49 shows the effect of wholesale electricity prices on the sum cost per kg hydrogen produced.

Figure 49. Wholesale Electricity Cost Scenario Cost £/kg Hydrogen Production Chart.



7.5. Observations

7.5.1. Gas to graphene

Gas to graphene scenarios 2c and 4c have been excluded from the cost comparison. There was little publicly available data to develop detailed costings. The OGTC Phase 1 Report, shows a capex of £1.25/ MW H_2, but without detailed insight into cost build-up this cannot be verified and cannot be used as an indicator against the costings included for the scenarios within this study. Cost comparisons for scenarios 2c and 4c are therefore considered as recommendations for further study. It should be of importance given the promising economics also shown in the OGTC Phase 1 report which outlines a very promising financial case given high graphene market prices.

Source: (OGTC (Phase 1 project report, HS413), 2019)

7.5.2. SMR

The costings show that the SMR scenarios have a lower associated cost in comparison to the electrolyser technology scenarios, which is consistent with other publicly available resources reviewed for the purpose of this study.

Hydrogen produced through SMR it should be noted, cannot be zero-carbon due to the emissions from continued fossil fuel production and the incomplete capture and injection of CO_2.

7.5.3. Electrolysis

The cost of green hydrogen produced by electrolysis will drop with continued advances in electrolyser technology and desalination technology. The price of electricity is a key factor in cost competitiveness of hydrogen produced through electrolysis and is a significant determining factor for cost competitiveness.

Electricity price in the Base Case is 10.85 p/ kWh (£108.5 p/ MWh). This is in line with a 'Very Large' non-domestic consumer size and includes the Climate Change Levy (ref Electricity Generation Costs 2020 (publishing.service.gov.uk)). Electricity cost is a significant influence on the lifespan cost of produced hydrogen for Scenarios 1 and 2b, totalling circa 60% of lifespan £ kg/H_2. The benchmarked electricity price includes costs of transmission, therefore purchase of wholesale electricity would significantly decrease the cost of electricity, and the overall cost of produced hydrogen. As shown in Figure 49, where a wholesale price of 4.6 p/ kWh (£46.83 p/ MWh) (ref Wholesale electricity charts and indicators | Ofgem | Ofgem) is considered, the life-span cost of produced hydrogen falls by 33%.

An indicator of electricity cost sensitivity to the overall production cost of green hydrogen is well demonstrated through Norwegian electrolyser maker Nel, who recently published plans to reduce their electrolyser costs by approximately 75% in a new 2GW onshore facility to a price of \$1.50 kg/H_2 (£1.07 kg/H_2) for green hydrogen by 2025. A significant factor in this reduced price is an assumed electricity cost of \$20/ MWh (£14.4/ MWh) (ref NEL to slash cost of electrolysers by 75%, with green hydrogen at same price as fossil H_2 by 2025 | Recharge (rechargenews.com)). The International Renewable Energy Agency have also shown in projections for reduced hydrogen production costs an assumed future price of \$20/ MWh (£14.4/ MWh).

Source: (IRENA, Green hydrogen cost reduction, Scaling up electrolysers to meet the 1.5'C climate goal, 2020)

If this level of cost could be released for the hydrogen production scenarios included in this study, there would be a reduction in produced hydrogen cost from the wholesale scenario of 25%.

The two assumptions for electricity cost have been included to demonstrate its impact on hydrogen production price and allow SOWEC to model indicative costs based on their own future projections for electricity cost.

From an economic modelling perspective, the purity of hydrogen produced through electrolysis will demand a higher market price (not assessed within this study), which does improve the scenario economics. Associated oxygen production if captured could also be sold to further improve the economic case.

Example of scenario cost build-up is provided below, showing the major capex blocks for scenario 2a.

Figure 50. Scenario 2a – Major capex blocks

Input Variable	
Electrolyser Power	60 MW
Cable from Wind farm (AC)	10 km

Cost Block	Costing Equation	Cost Estimate (£ MM)
Wind farm Cable	No of cables 1. Max power 60 MW	10
Electrolyser	£0.4 MM /MW	5
Pipeline Mods	£10 MM / Pipeline (assuming pre request work has been completed to identify pipeline as a viable candidate)	10
Desalination Plant	6500l/MW/day → 35% efficiency → £52.6k/2000l	1.2
Compressor	£1.15 /kg H2	9.1
Auxiliaries	4 times general equipment cost (high end assumption)	145
	Sub Total	***201***
Platform Mods	Weight 1,224 te	42
PSA	Incl. (option to mix with existing natural gas pipeline) → £800 per Nm3/ hr	9
	Sub Total	***252***
	General and &Administrative expenses @ 15%	***38***
	Sub Total	***290***
	Contingency @ 30%	***87***
	Total capex incl G&A	***377***

7.6. Industry demand for hydrogen

Whilst strictly outside the scope of the repurposing cost estimate, this study has reviewed figures to assess the likely demand for hydrogen at demand centres (clusters). This information has been included because demand at regional clusters is likely to have an influence on decision making, as regards repurposing of existing oil and gas infrastructure.

The “elementenergy” report, Hydrogen in Scotland, July 2020 estimates significant hydrogen demand across a range of industries including chemicals; oil and gas processing; food and drink; glass, paper and pulp; and non-ferrous metallurgy. Figures presented in Figure 51 assume hydrogen replaces all fuel demand (excluding industries such as cement, ethylene, iron and steel, and refineries.)

Figure 51.Expected hydrogen production. Source: (elementenergy; Hydrogen in Scotland, 2020)

Scenario	Expected Hydrogen production (TWh/y) 2030	Expected Hydrogen production (TWh/y) 2045	Expected Hydrogen production (TWh/y) 2050
Regional Growth	12.6	19.4	19.4
Scottish Hydrogen Economy	13.6	72.7	72.8
European Outreach	13.6	113.7	120.8

When these target figures are compared with current hydrogen generation capacity, this demonstrates a clear demand for hydrogen generation projects. The scale of potential hydrogen production from different technology configurations is shown below in Figure 52. The extent to which SMR or electrolyser technology is deployed offshore and in a repurposing scenario is discussed in Section 10 of this report.

Figure 52. Expected hydrogen production from green and blue technology sources (consolidated list from identified data sources below).

Class	Hydrogen production (TWh/y)	Configuration	Expected
Green	12.0 TWh/y	4GW, full scale 20 x 20 array hydrogen wind farm (400 x 10MW turbines) *Source (BEIS - Dolphyn, 2019).*	2037
Green	0.3 TWh/y	100 MW- first commercial offshore hydrogen wind farm (10 x 10MW turbines) *Source (BEIS - Dolphyn, 2019)*	2032
Green	0.03 TWh/y	10MW – pre-commercial facility (single operating unit) *Source (BEIS - Dolphyn, 2019)*	2026
Green	0.006 TWh/y	2MW - prototype (single operating unit) *Source (BEIS - Dolphyn, 2019)*	2023
Blue	0.0005 TWh/y	Containerised unit (x1) based on 540 kg H2 per day and 187 T/yr hydrogen produced. *(OGTC (Phase 1 project report, HS413), 2019)*	Existing
Blue	0.02 TWh/y	Large Offshore SMR Plant based on 12,000kg H2 per day and 4,380 T/yr hydrogen produced.	Existing

There is total operational offshore wind capacity in Scotland of approximately 900MW, with a further total consented 5.6GW. SOWEC has a vision of 8GW by 2030 and the Scottish Government has indicated that as much as 11GW of installed capacity may be achievable by 2030. Source: (Scottish Government, 2020)

(Offshore wind policy statement - gov.scot (www.gov.scot), October 2020)

The Scottish Government has also quantified a number of scenarios for hydrogen production from offshore wind (see Figure 53 below). Planned developments are expected to provide a total of 15GW of offshore wind capacity by 2032 and a total of 30GW of offshore wind capacity by 2045. Both of these scenarios would be more than enough to meet the expected demand for hydrogen shown in Figure 53. *Offshore wind to green hydrogen: opportunity assessment - gov.scot (www.gov.scot)*

Figure 53. Hydrogen Production from Offshore Wind in Scotland (2025-2045). Source: (Offshore wind to green hydrogen: opportunity assessment, 2020).

Hydrogen Production from Offshore Wind in Scotland (2025-2045)					
Scenario	**Projected offshore wind capacity (GW)**	**100% offshore wind to green hydrogen potential (GWh/year)**	**Scotland's hydrogen demand (GWh/year)**	**Offshore wind capacity required to meet Scotland's hydrogen demand (GW)**	**Percentage of total wind capacity required for hydrogen demand**
2025					
Ambitious	5.8	17,945	1,990	0.64	11%
Planned development	5.4	16,707	1,730	0.56	10%
Business as usual	3.4	10,518	403	0.13	4%
2032					
Ambitious	20.0	65,578	21,786	6.6	33%
Planned development	15.0	49,183	20,356	6.2	41%
Business as usual	13.0	42,620	7,884	2.4	18%
2045					
Ambitious	60	202,142	75,976	22.6	38%
Planned development	30	101,072	65,492	19.4	65%
Business as usual	27	90,964	20,141	6	22%

7.7. Data sources used to develop overview of cost estimates

- On the economics of offshore energy conversion: smart combinations – converting offshore wind energy into green hydrogen on existing oil and gas platform in the North Sea. Jepma, C.J.. 03.02.2017.
- Hydrogen – the role of hydrogen storage in a clean responsive power system. Energy Technologies Institute.

- Hydrogen Production and Distribution. Energy Technology System Analysis Programme. February 2014.
- The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs (2004). National Research Council and National Academy of Engineering (USA). 2004.
- Khzouz, M.; Gkanas, E.I.; Shao, J.; Sher, F.; Beherskyi, D.; El-Kharouf, A.; Al Qubeissi, M. Life Cycle Costing Analysis: Tools and Applications for Determining Hydrogen Production Cost for Fuel Cell Vehicle Technology. Energies 2020, 13, 3783. https://doi.org/10.3390/en13153783
- OGTC Phase 1 Project Report, Delivery of an offshore hydrogen supply programme via industrial trials at the Flotta Terminal HOP Project – HS413 [website Delivery of an offshore hydrogen supply programme via industrial trials at the Flotta Terminal - Phase 1 project report (publishing.service.gov.uk)].
- E4tech elementenergy – Electrolysis in the EU – Appendix 1 [website:5 APPENDIX 2B FCHJUElectrolysisStudy (ID 1329459).pdf (europa.eu)];
- Scottish Government Hydrogen Policy Statement.
- Dolphyn Hydrogen, Phase 1 – Final Report, Department for Business, Energy and Industrial Strategy, 9 October 2019

8. Project risks and opportunities

This section of the report is intended to provide an overview of general risks, threats and opportunities associated with a hydrogen repurposing project that developers will need to consider.

The basis for the identification and assessment of risks and opportunities is a literature review, safety hazard identification study and a consultation exercise with relevant stakeholders,

The scope of the assessment covered:

1. Scope of infrastructure being considered;
2. Economics;
3. Technical feasibility;
4. Proximity and connectivity;
5. Policy, regulation, codes and standards;
6. Quality;
7. Safety;
8. Environmental;
9. Availability and reliability;
10. Supply chain;
11. Communication; and
12. Synergies with oil & gas decommissioning and life extension.

The process used to identify and assess hazards, threats and opportunities relevant to the repurposing of existing oil and gas infrastructure is summarised here.

Figure 54. Process to identify and assess hazards, threats and opportunities.

8.1. Identification of hazards, threats and opportunities

The review considered major accident hazards, environmental aspects, occupational safety hazards and security threats associated with an offshore project. The process was informed by our experience of the Offshore Safety Case regime, pipeline safety, electrical safety (power, transmission, switchgear), Construction, Design and Management (CDM) regime and marine operations.

The materiality index for safety and environmental accidents and incidents reflects industry standards, guidance and regulation of offshore and onshore industries in the UK.

8.2. Consultation and engagement with stakeholders.

The consultation exercise supplemented the hazard identification process to:

- verify findings of the literature review;
- identify gaps in the literature review data; and
- identify areas for further study.

The basis for the consultation process was a question set that was sent to a cohort of stakeholders and interested parties of relevance to the repurposing of existing oil and gas infrastructure for the production of offshore hydrogen. Stakeholders included regulators, industry trade bodies, developers of offshore renewables projects, oil and gas operators, engineering contractors decommissioning organisations, port authorities, local councils and economic development organisations.

The question set was designed to reflect risk areas which have the potential to materially influence the success or failure of a project to repurpose oil and gas infrastructure for offshore hydrogen production. The question set was designed to be as open as possible to encourage stakeholders to apply a broad interpretation to the question which reflected their individual area of expertise, or business.

- In all, over 60 consultation letters were despatched to key organisations.
- Feedback was received from approximately 15% of respondents.
- A small but significant number of consultees actively declined to participate, citing conflict of interest and confidentiality as the reasons.

8.3. Assessment of risk and opportunity

An assessment of risks and opportunities identified during the hazard identification process applied a simple scoring matrix to rank the residual risk, taking account of mitigation considerations. The scoring matrix is presented in Figure 55.

Figure 55.Scoring matrix to rank residual risk.

Novel concept / scenario with poorly defined regulation, minimal guidance, significant challenges, conflict, high cost, significant gaps in knowledge and capability. Identified in stakeholder consultation as a challenge.	High
Emerging concept / pilot project with readily transferable / adaptable regulation and guidance, cost models and risk management practices from existing offshore and onshore industries e.g. COMAH, Safety Case, CDM, PPC, Marine Licensing, EIA, Permits, licenses, consents, verification schemes, Class and similar HSSEQ regimes.	Medium
Established practice in industry with established cost models, risk management practices regulatory framework, guidance, codes, standards, procedures and permits from existing offshore and onshore industries. E.g. COMAH, Safety Case, CDM, PPC, Marine Licensing, EIA, Permits, licenses, consents, verification schemes, Class and similar HSSEQ regimes.	Low
Opportunity for advancement (economic, technical, safety, security, quality and / or environmental performance).	Opportunity

8.4. Mitigations and controls

Mitigations and controls associated with the risks identified during the process were assigned at a high level. The intent is to reflect the maturity of the repurposing proposition and the extent to which detailed controls will be influenced by high level politics, regulation, views of industry bodies and other high level decision making groups.

High level mitigations and controls are presented in Appendix K.

8.5. Risks and challenge areas identified during the study

Key risks and areas of challenge arising from each study theme are presented below.

Economics

- Economic uncertainties associated with the condition of redundant pipelines. Estimating the costs of decommissioning a pipeline in the North Sea represents an on-going challenge for the industry. Factors such as limited experience, technical unknowns, integrity uncertainties and the significant variation in pipeline configurations make it very difficult to forecast costs with any real degree of accuracy. This uncertainty is expected to extend to the repurposing of redundant pipelines (OGUK, 2013);
- Costs associated with re-purposing as a viable alternative to decommissioning (ABEX, OPEX revenue generation to cover ongoing costs; OPEX on HSE risk);
- The switch over of jackets to hydrogen production will require significant CAPEX with the disposal of contaminated units being required;
- Commodity pricing and the future price of hydrogen and green electricity;
- Operating cost to maintain offshore facilities associated with offshore hydrogen generation.

Technical feasibility

- Potential conflicts between proposals for re-use of infrastructure, above and below seabed for: CO_2 transport and storage; hydrogen generation and transport; other potentially unrelated uses, e.g. siting of offshore wind installations;
- Hydrogen compatibility with existing pressure-containing infrastructure: flowrates; pressures; gas composition; space; and available power;

- Reuse opportunities for rigid steel pipelines recovered by the reverse reeling process are limited. Subjecting a pipe to multiple cycles of plastic deformation during both the reeling and reverse reeling processes would likely compromise its integrity. (OGUK, 2013)
- Efficiency and size of electrolysers;
- Geological storage of CO_2 and protection from inadvertent sterilisation;
- Water depth and bathymetry with regard to the consideration of water depth and bathymetry in relation to the existing infrastructure; and storage of hydrogen in the offshore environment;
- Understanding the real situation with regard to assets. Are they suitable for re-purposing?;
- Between the platforms there is a possibility to use machinery that is less than 25 years old. If it is the intention to use existing machinery, platforms must have sufficient running hours remaining to make repurposing and refit a viable proposition;
- Expectation not to use a platform that is likely to cease operation before 2030.

Policy, regulation, codes and standards

Requirement for clear guidance from regulators to ensure:

- Re-use opportunities are realised; and
- Progress with decommissioning projects is not adversely affected while awaiting reuse opportunities.

Quality, safety and the environment

- Safety and the limited research on the toxicology of graphene.
- Hydrogen export by existing natural gas pipeline and the challenges presented by the differences in physical and chemical properties between hydrogen and natural gas (methane).
- Current condition as regards the integrity of the pipelines and influence that the hydrogen gas has on the fatigue properties of existing pipelines;
- Not identifying areas of high corrosion and/or particularly thin walls and overestimating the integrity of an existing pipeline for its new duty of transporting hydrogen;
- The suitability of existing equipment for high hydrogen content with regard to stress cracking etc. (The suitability of carbon steel pipelines for transporting hydrogen gas or mixtures has been identified as being dependent on a number of embrittlement and degradation mechanisms, which are attributed to hydrogen. Hydrogen service causes embrittlement: a reduction in yield strength and fracture toughness and an increased crack growth rate, leading to reduced fatigue life. Hydrogen blistering, sulphide stress cracking and hydrogen induced cracking are possible where hydrogen is blended with sour natural gas, although for pure hydrogen service this is not applicable. The recommended pipeline material grades for hydrogen service are API X42 and X52. Grades above X52 are more likely to be severely affected by hydrogen embrittlement). *Source: (OGTC (Phase 1 project report, HS413), 2019);*
- Higher operation and maintenance expectations, due to the higher velocity of the lower density and lower calorific value hydrogen compared to natural gas;
- Consideration must be given to the integrity of wells used for the storage of CO_2 from associated carbon capture processes to ensure there is no leakage;
- Awareness and familiarity of the traditional offshore supply chain with hydrogen issues and solutions.

Availability and reliability

- Reliability challenges associated with a constant supply of renewable power from nearby wind farms;
- Storage capacity for the storage of hydrogen and CO_2;
- Use of raw seawater and corrosion problems at high demand;
- Remaining life span of the structure from sea-bed to surface;

Synergies with oil & gas decommissioning and life extension

- Transfer of decommissioning obligations and liabilities;
- Relationship to decommissioning plans;
- Pipeline availability and potential conflict with decommissioning plans;
- Aged infrastructure approaching cessation of production (CoP) will have had maintenance budgets managed carefully to the extent that future lifespan may be questionable;
- Potential conflict, regarding the co-use of oil and gas infrastructure with other revenue generating streams, such as hydrogen generation which could result in a delay in de-commissioning activities.

Supply chain

- Limited local manufacturing capacity for desalination & electrolyser equipment to meet growing demand.

8.6. Opportunities identified during the study

Opportunities identified during the study are presented, as follows:

Economics

Consultees identified remote operation from shore as being an important factor in reducing OPEX and improving personnel safety.

Technical feasibility

- Future developments in offshore sizing of SMR technologies. Recent research in the international ELEGANCY project has investigated refinement of these processes as a step toward reforming at sufficiently compact scale for operation on offshore installations. Reformer plant size is currently assessed as suitable for a Floating Production, Storage and Offloading facility. The intention is to continue refinement of the reformer technology for implementation on smaller offshore infrastructure;
- Potential for inter-seasonal hydrogen storage in depleted gas fields or within the pore space of geological formations;
- Rigid steel pipelines can be recycled along with some of the coatings that may be applied to them. Likewise, flexible pipelines, umbilicals and power cables can be processed to separate their metallic and plastic components and then recycled; and
- Potential opportunities may exist for the reuse of flexible pipelines and umbilicals if their post recovery integrity can be confirmed.

Proximity and connectivity

- Potential for communication infrastructure to be interfaced with offshore power generation infrastructure.

Quality, safety and the environment

- There are very robust systems in place for managing quality offshore, these should be followed and transposed for the production of offshore hydrogen;
- There are very robust existing systems in place for managing safety offshore, these should be followed and transposed for the production of offshore hydrogen;

Supply chain

- There is value in transitioning (re-purposing) a workforce in the same way as there is a piece of infrastructure;
- Capacity to handle topside repurposing in local shipyards;
- Availability of an established supply chain and transferable skills; and
- The offshore supply chain is probably well suited to the continued provision of pipeline services to a hydrogen industry.

Synergies with oil & gas decommissioning and life extension

- Offshore work scopes to repurpose elements of infrastructure could synergise with decommissioning projects. e.g., elements of pipeline infrastructure could be removed using the same vessel and project team as were repurposing a pipeline.

Other benefits

- Explaining to the public and oil field workforce that the application of hydrogen is a way to secure the long-term future of the offshore industry.

9. Review of key issues identified in the study

This section of the report is intended to draw together subject-specific issues arising from the individual study areas. This information is used to inform the conclusions and recommendations in Section 10.

9.1. Existing infrastructure and proximity to energy hubs and service amenities

Within the context of the three hydrogen generation technologies and six hydrogen repurposing scenarios developed, the availability of energy hubs, service amenities and existing oil and gas infrastructure is not in doubt. It is the suitability of the technology, generating scenarios and existing oil and gas infrastructure that must be determined before committing to a re-purposing project.

Candidate infrastructure assessed in this report include:

- Converted bulk carriers, FPSOs and similar vessels;
- Surface infrastructure (large fixed installations in NNS and CNS);
- Subsurface infrastructure (well heads, manifolds, mattresses and other subsea equipment);
- Pipelines;
- CCUS infrastructure;
- Existing cable arrays and power transmission infrastructure; and
- Yards and port facilities.

Note: NUIs were excluded from the review as they are located in the shallower waters of the SNS.

9.2. Existing development and consenting processes

This review of the regulatory framework, as it may be applied to the re-purposing of existing oil and gas infrastructure for offshore hydrogen production confirms that there is a solid foundation on which to build. A solid cascade of legislation has been established that can be applied to the re-purposing agenda; an experienced cohort of regulators and statutory consultees has been regulating related activities for many years. This is all underpinned by a permitting and authorisation regime and canon of international safety and environmental codes of practice.

However, what is not known is the extent to which this regulatory framework addresses all requirements of a repurposing project; where the gaps exist, how much effort is required to modify existing regulations, codes and standards or to develop new regulations, if required. To understand these gaps, and to plan a road map ahead, a review of regulations, roles and responsibilities, codes and practices is advised.

9.3. Electrolyser technologies

Electrolysis is a well-established and well-known process for producing hydrogen from water in an electrolyser unit. However, further work is required if offshore electrolysis is to be adopted as a primary means for the generation of offshore hydrogen, particularly when associated with repurposed oil and gas infrastructure. Projects such as the PosHYdon pilot will provide a useful measuring stick for successful application which could be applied to candidate infrastructure in the UKCS.

Highlighted below are several key areas of focus if the technology is to be considered as an option for hydrogen generation through repurposed infrastructure:

- Footprint and weight of units;
- A continued drive to reduce costs, particularly material costs;
- Extension of operating life;
- Continued development and focus on enabling technology including desalination, particularly on reducing associated footprint and cost of materials;
- Continued development of systems able to adapt to intermittent and fluctuating power supply from offshore renewable power;
- Comparison of relative benefits of onshore and offshore electrolysis to steer the focus for future development;
- Lack of an electrolyser manufacturer in Scotland, which is highlighted as a key issue.

9.4. Costs associated with hydrogen generation scenarios

The results of this study, and previous studies conducted by the Vysus Group (previously Lloyd's Register) team indicate that cost estimates at the study/ feasibility level should be used to inform scenario evaluation but should not be the dominant criterion. Each scenario has specific technical requirements and risks which need to be considered in any repurposing evaluation.

With specific regard to the cost element of a re-purposing proposition, a number of items have been highlighted for further consideration:

- Re-purposing may require a complete re-build of the platform offshore i.e. removing all the existing equipment to create space, structural reinforcement as required and new equipment installation. Costs will vary significantly based on individual circumstances. The costs of removing existing topsides module(s) from the "donor" platform have not been included due to the difficulty in standardising these costs.
- Existing infrastructure must be assessed on a case-by-case basis with the CoP date as a focus point. Assessment of repurpose potential will take considerable time and effort and should be undertaken well in advance of COP/ decommissioning programme start. Which party bears the cost and effort for these assessments must also be determined.
- Onshore new build facilities will likely offer significant cost savings; examples would include reduced transportation costs due to market proximity, reduced logistical costs and labour rates whilst also improving productivity and lower indirect costs. Onshore new build facilities have not been assessed within this study but opportunities should be an area of focus. The potential reuse of existing offshore infrastructure to support new build developers should also be considered e.g. recycled material.
- There may be potential for some equipment to be repurposed for a new facility without the constraints of ageing infrastructure which is not fit for long-term continued use. Further study is recommended to assess the cost savings associated with new build hydrogen facilities as opposed to repurposing existing infrastructure.
- A viable hydrogen economy will likely require integration with CCS. Carbon pricing will be a significant factor in determining viability and encouraging transition projects.
- Benchmark figures used in the cost modelling of repurposing scenarios suggest the current capital cost of an SMR plant installed on a large asset to be approximately 1.5 times less expensive than a similar sized electrolysis plant installed on a similar sized asset. Comparative figures for a gas to graphene scenario are not currently available.

Where cost comparison between technologies is possible, a simple comparison should be avoided. This important as the economics associated with a technology, or project are expected to be influenced by:

- the maturity of the technology
- rises in market demand
- increasing availability of local supply chains;
- economies of scale and ability to host multiple units on one site;
- wholesale electricity prices;
- commodity prices for hydrogen and graphene
- carbon pricing, and
- limiting factors such as deck capacity.

9.5. Risks and opportunities.

A number of risks and opportunities were identified during the study. The areas identified reflected the scope of the enabling elements regarded as being material to the delivery of a safe, secure and economically viable repurposing project.

Risk areas identified during the study were ranked according to a simple set of criteria designed to reflect the availability of a technical, regulatory or procedural solution. A graphical representation of priority areas is provided in Figure 56.

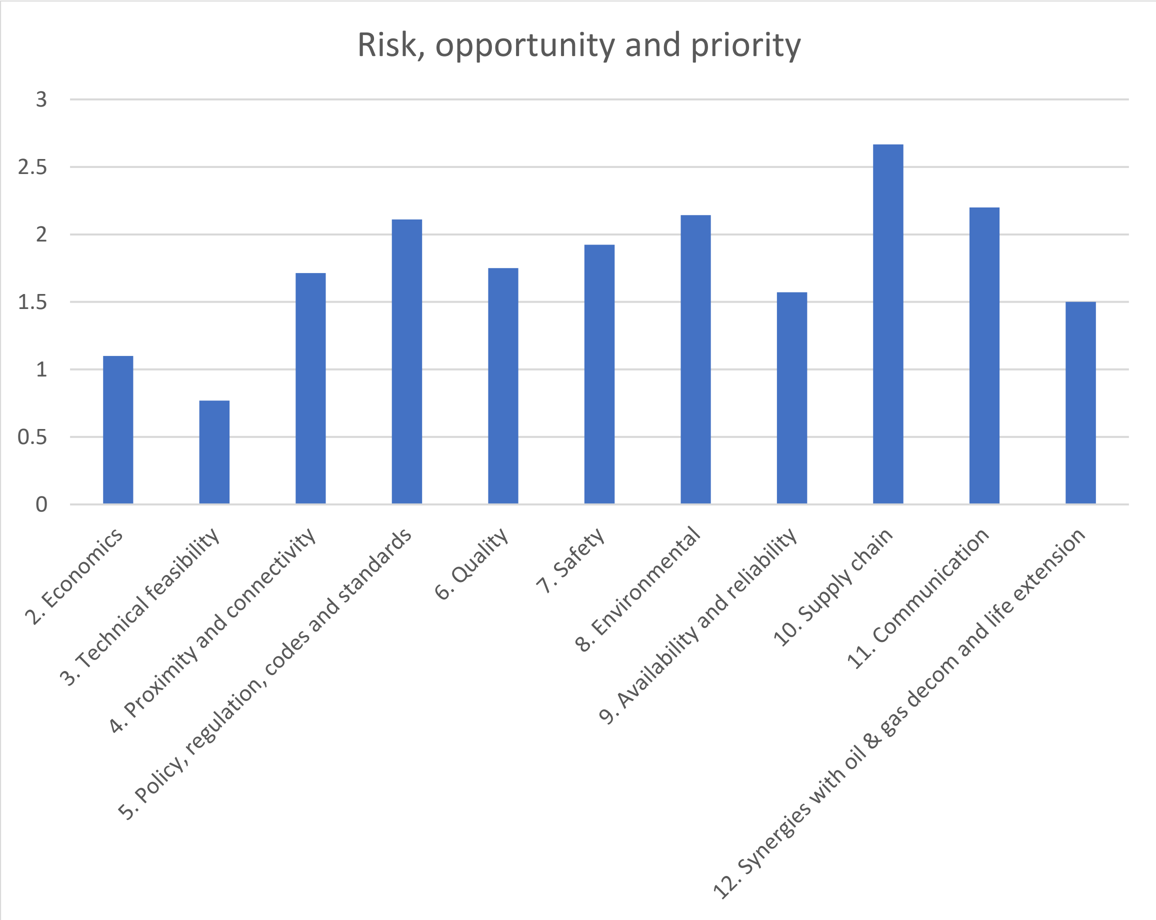
Figure 56.Priority areas identified during the process to identify project risks and opportunities

In order of priority, where the lowest score corresponds to the lowest level of maturity / readiness this diagram shows technical issues to present the greatest challenge. As the resolution of technical issues is closely aligned to cost, economics is a close second.

Of the other areas considered in the analysis, these too have challenges, but solutions are considered to be transferable from existing oil and gas areas of expertise, offshore wind farm and onshore experience.

Where a low number equates to a high priority, the existing skilled supply chain emerges as a clear area of opportunity with the potential for transfer to the hydrogen sector and repurpose of oil and gas infrastructure.

Figure 57. Risk, opportunity and priority (lowest number equals highest priority).



10. Discussion, conclusions and recommendations

This study reviewed six scenarios to identify opportunities and risk associated with the repurposing of oil and gas infrastructure for offshore hydrogen production.

Importantly, the study did not consider the repurposing potential of specific assets for hydrogen production, the relationship to specific offshore wind farms, specific demand centres or broader points concerning the role of hydrogen in a net zero economy.

To identify generic risks and opportunities associated with the repurposing potential of existing infrastructure, a number of elements were established to guide the process:

- proximity and connectivity to energy hubs and demand centres;
- technical feasibility;
- economics;
- policy, regulation, codes and standards;
- quality, safety, environmental aspects;
- availability and reliability of plant and equipment;
- availability of a suitable supply chain;
- communication; and
- synergies with decommissioning and life extension.

Hydrogen generation technology considered for duty on repurposed assets included steam methane reforming, electrolysis and gas to graphene.

10.1. Discussion

10.1.1. Capacity

- Generation of green or blue hydrogen offshore is technically feasible. SMR and electrolysis are well established technologies, albeit at differing stages of commercial development for offshore service. Gas to graphene is the least developed of the technologies reviewed in this study and needs further study.
- Potential candidate infrastructure situated in the NNS is ideally located for repurposing as a hydrogen production host. Existing infrastructure is located in close proximity to enabling infrastructure such as OWFs, energy hubs, CCUS infrastructure, cabling and demand centres which make them ideally placed for redevelopment.
- CCUS facilities and onshore demand centres have been established to the extent that a number of interlinked CCUS / hydrogen generation projects are at a relatively advanced stage. These constitute a potential market for repurposed oil and gas infrastructure to act as host installations for equipment.
- Relevant assets for repurposing have been identified as converted bulk carriers, FPSOs and similar vessels; surface infrastructure (large fixed installations in NNS and CNS); subsurface infrastructure (well heads, manifolds, mattresses and other subsea equipment); pipelines; CCUS infrastructure; existing cable arrays and power transmission infrastructure; and yards and port facilities
- Whilst technically feasible, the viability of a repurposing project is dependent on non-technical factors. These factors include economics and the adequacy of regulatory, QHSE and associated management frameworks to govern and operate the complex range of activities associated with a repurposing hydrogen generation project.

- Synergies between repurposing and decommissioning scenarios have been identified in this study. However, the extent to which these may be realised is dependent on a range of technical, political, regulatory and economic factors.

Economics

Costs generated in this study are predicated on the availability of suitable candidate infrastructure for hydrogen production. Indicative installations identified by the OGTC include a converted bulk carrier, decommissioned structures in the NNS and CNS such as the base case Brent Bravo and Delta installations; and FLAGS pipeline. OGTC also identifies the NUIs in the CNS Markham field as candidates for repurposing. However, these are out of scope.

The results of a linear cost comparison analysis between electrolysis and SMR suggest that at this point in time, SMR is the more attractive option. However, where these technologies are compared over a longer time period, electrolysis emerges as the more favourable option from an economic point of view.

- The capital cost of electrolysis equipment is expected to decrease to rival SMR, as economies of scale improve to meet growth in global markets;
- Electrolysis is expected to offer a longer production life, and lower operation and maintenance costs;
- Electrolysis is not associated with the production of CO_2 as a by-product, and thus avoids the associated cost of CO_2 disposal;
- Electrolysis is not associated with GHG emissions that are likely to attract increasing levels of taxation and mitigation costs.
- Comparison of likely production volumes from SMR and electrolysis units indicates that offshore SMR may be more suited to a “tactical” deployment to support emissions reductions at the asset level. A large number of offshore SMR units would be required to support large-scale hydrogen production and SMR may therefore be better suited to onshore deployment. Electrolysis, by contrast, is expected to be capable of delivering the necessary volumes if deployed offshore.

When considered as part of a re-purposing scenario, this study highlights a number of issues that are expected to have a direct impact on the cost of a development:

- The cost of addressing technical and safety challenges identified in this report represent significant hurdles which need to be addressed. Once these risks are better understood, it is expected that the degree to which costs can be accurately modelled will increase to reflect the actual magnitude of the hurdles. It is expected that this should lead to a reduction in associated cost.
- Re-purposing of an existing installation may require a complete re-build of an offshore platform and involve the removal of all the existing equipment to create space and achieve structural reinforcement to accommodate new equipment. Costs associated with a complete re-build will vary significantly, depending on individual circumstances. Note: the costs of removing existing topsides module(s) from the "donor" platform have not been included due to the difficulty in standardising these costs.
- Onshore new build facilities are expected to offer significant cost savings over offshore solutions. Onshore solutions are expected to have lower costs associated due to the proximity of generating plant to end user, and beyond. Other savings are expected to reflect the lower costs associated with logistics, labour rates and HSE risk management.

Adequacy of regulatory, QHSE and associated management frameworks

The existing regulatory and management framework, as documented in this report, should provide a sound basis on which to repurpose existing oil and gas infrastructure for offshore hydrogen production. However, as previously discussed, significant hurdles exist which need to be addressed if progress is to be made:

- A nascent offshore hydrogen industry has the benefit of a regulatory framework that has been established over many years to regulate offshore and onshore industrial development. This framework comprises a cohort of regulators, statutory consultees, regulations, standards and approved codes of practice. The framework is further supported by guidance published by regulators and industry bodies outside the UK, which have relevance to activities associated with the production of offshore hydrogen and re-purposing of existing infrastructure for this purpose. However, the adequacy of the framework for all hazards, threats and environmental aspects associated with repurposing/offshore hydrogen generation is not known, i.e. gaps in knowledge or responsibility have not been defined.
- Alongside the regulatory framework, there exists a mature suite of management systems, policies, procedures and interface arrangements to manage the cascade of expectations between regulators, independent verification bodies, developers, operators, contractors, supply chain and other stakeholders such as financiers and joint venture partners. However, anomalies, differences and gaps exist. Again, the extent to which gaps exist is not defined.

10.1.2. UK content targets (including where relevant Scottish Government ambition for local content in ScotWind projects)

The Scottish Government Hydrogen Policy Statement has identified three scenarios to develop a hydrogen economy over the period 2025, 2035, and 2045 where between 70,000 and 300,000 jobs will be protected or created with GVA impacts of between £5 billion and £25 billion by 2045.

- Regional Growth;
- Scottish Hydrogen Economy;
- European Outreach (exporter of hydrogen).

During this period the Scottish Government expects to increase production from small scale operations with circa 200 MW per unit production capacity for green hydrogen to over 25 GW total by 2045. The majority of the green production is expected to be offshore at large scale.

Achieving the upper range of these scenarios, which envisages Scotland as a major exporter of green hydrogen to Europe by 2045, will require innovation, skills and knowledge building to support the huge amount of effort, investment and regulatory action identified in the policy document as being necessary to achieve the vision.

Whilst it was beyond the scope of this study to analyse the extent to which the repurposing of the existing offshore oil and gas workforce could contribute to the economic achievement of the vision, it is possible to comment on other key issues:

- Consultees positively identified the current offshore and onshore workforce as being ideally suited to the repurposing of existing offshore infrastructure for hydrogen production, and a low carbon future in general. The work force, supply chain and other stakeholders are already highly experienced in the safe, secure and economically prudent execution of all activities required to manage an asset through all aspects of its

lifecycle (design, construction, commissioning, operation, maintenance, late life and decommissioning.) Organisations such as the OGTC are currently evaluating technology transfer and the contribution of the oil and gas industry to the net zero agenda.
- Skills gaps were however identified by consultees with respect to the management of hydrogen specifically. This gap is expected to be addressed by adopting a similar approach to hydrogen safety and competency management as is the case with COMAH and Safety Case.

10.1.3.Industry demand in likely Hydrogen clusters.

The “elementenergy” report, Hydrogen in Scotland, July 2020 estimates significant hydrogen demand across a range of industries including chemicals; oil and gas processing; food and drink; glass, paper and pulp; and non-ferrous metallurgy).

Figures quoted in our assessment of costs and economics suggest that offshore electrolysis is expected to make a meaningful contribution to hydrogen generation across the three scenarios (Regional Growth, Scottish Hydrogen Economy, European Outreach). In this context, it would be reasonable to conclude that the repurposing of suitable oil and gas infrastructure for the hosting of hydrogen generation equipment should be considered as a viable option.

The ability of SMR to meet hydrogen generation demand via its use as part of a repurposing of existing offshore infrastructure is less clear.

Onshore SMR, associated with a CCUS facility to mitigate CO_2 by-product is considered the preferred option for hydrogen production in the immediate term. There are fewer barriers to the physical scale up of the plant and the associated costs, technical and regulatory hurdles to be overcome.

Offshore SMR, provided as a containerised option may have a very real role to play in the reduction of greenhouse gases associated with oil and gas production. In this context, carbon pricing would be expected to increase the attractiveness of the option if CO_2 could be managed via the associated CCUS facility and hydrogen used as a fuel gas to replace methane and diesel sources. Technical and economic barriers to the adoption of SMR offshore at a scale that can rival onshore plants makes this look like a challenging option.

The lack of detailed information for gas to graphene precludes detailed consideration of this technology. Once data are available, then a formal comparison will be justified.

10.2. Conclusions

The conclusions presented here are drawn from key points addressed in the discussion of candidate infrastructure; technology; economics, capacity and demand; adequacy of regulatory, QHSE and associated management frameworks; UK content targets; and industry demand.

Importantly, the study does not attempt to draw conclusions about broader points concerning hydrogen production or attempt to identify specific infrastructure as candidates for repurposing.

Candidate infrastructure

Existing offshore infrastructure identified as having the potential to be re-purposed for the production of offshore hydrogen may be categorised, as:

- In service and end of life floating and fixed production installations, with larger fixed installations located in the NNS and CNS;
- End of life pipelines, with candidates for export or storage of hydrogen product, disposal of CO_2 and the import of natural gas feedstock for SMR operations located in the NNS and CNS;
- Subsurface storage facilities already identified for CCUS service which will be required to capture the CO_2 by product of SMR hydrogen production; and
- Subsea infrastructure such as well heads, manifolds, mattresses and other subsea equipment. It is noted, however, that these are unlikely to have a major impact on the overall cost of a hydrogen generation project.

Brent infrastructure located in the NNS and Markham field in the CNS is ideally situated to be considered as a provider of donor sites as these are located in close proximity to connecting pipelines and OWF developments.

A converted bulk carrier proposal is ideally to suited to provide a platform to host hydrogen production equipment from constrained offshore renewable resources found to the north of the Scottish mainland.

Supply chain infrastructure necessary for the repurposing of candidate oil and gas installations has been an established part of the Scottish oil and gas economy for many years. This infrastructure is well placed to support repurposing towards a hydrogen economy.

- Many ports routinely supply the offshore oil and gas industry and have already received decommissioned infrastructure removed from offshore fields with local supply chains processing the material.
- Scottish ports are located in relative proximity to North Sea oil and gas infrastructure; they demonstrate the physical means, organisational capabilities, and experience to support a repurposing effort which will require a multidisciplinary approach to repurposing.
- A multidisciplinary approach is expected to transcend engineering services, project management, marine operations, supply base logistics decommissioning and waste management.

Whilst there are real opportunities to re-purpose redundant pipelines which are located in relative proximity to donor infrastructure and OWFs, this report highlights a number of challenges that must be addressed by policy makers, industry and regulators if the infrastructure is to become available for repurposing:

- Economic uncertainties associated with the condition of redundant pipelines;
- Not identifying areas of high corrosion and/or particularly thin walls and overestimating the integrity of an existing pipeline for its new duty of transporting hydrogen;
- Integrity issues resulting from reverse reeling processes;
- Differences in physical and chemical properties between hydrogen and natural gas (methane). In particular, the suitability of existing equipment for high hydrogen content with regard to stress cracking etc. (The suitability of carbon steel pipelines for transporting hydrogen gas or mixtures has been identified as being dependent on a number of embrittlement and degradation mechanisms, which are attributed to hydrogen. The recommended pipeline material grades for hydrogen service are API X42 and X52. Grades above X52 are more likely to be severely affected by hydrogen embrittlement); and
- Pipeline availability and potential conflict with decommissioning plans.

Technology

This study into the application of SMR, electrolysis and gas to graphene technologies in theoretical repurposing scenarios concluded:

- SMR and electrolysis are both commercially viable, but – in the mid-term - electrolysis will be the preferred process for offshore hydrogen production;
- Whilst SMR currently enjoys a cost advantage, it is expected that electrolyser costs will reduce significantly as the market develops;
- Electrolysis does not carry the CO_2/GHG burden of SMR;
- One disadvantage associated with electrolysis is the lack of an electrolyser manufacturer in Scotland to take advantage of the expected growth in commercial demand for the equipment. Addressing this deficit should be regarded by policy makers as a priority item to stimulate the market and encourage growth of an indigenous industry;
- Onshore scalability of hydrogen production via SMR far beyond what can be achieved offshore suggests that offshore SMR is a technology for tactical purposes such as a production asset net zero emissions enabler. To realise potential as a net zero enabler, policy makers, regulators and industry need to consider the linkage between offshore SMR technology and the road to a low carbon future;
- Onshore SMR is likely to play an important role as an enabler of hydrogen market growth and development;
- Hydrogen production via the gas to graphene production process exhibits significant potential as a means of utilising the methane that would have otherwise been flared. The graphene production process is also expected to reduce costs associated with CO_2 emissions and flaring consent from a retrofitted oil and gas production asset. In common with SMR deployed offshore, gas to graphene production should be considered in the context of a net zero operating strategy to realise the full potential associated with a reduction in methane emissions and an expected increase in carbon tax.

Economics, capacity and demand

The Scottish Government Hydrogen Policy Statement has identified three scenarios where between 70,000 and 300,000 jobs will be protected or created with GVA impacts of between £5 billion and £25 billion by 2045.

- Regional Growth;
- Scottish Hydrogen Economy;
- European Outreach (exporter of hydrogen).

Publicly quoted figures suggest that demand for hydrogen is expected to outstrip production. This demand is expected to come from a broad range of industries including chemicals; oil and gas processing; food and drink; glass, paper and pulp; and non-ferrous metallurgy.

The results of cost comparison analysis between electrolysis and SMR suggest that at this point in time, SMR is the more attractive option for hydrogen generation. However, where these technologies are compared over a longer time period, electrolysis emerges as the more favourable option from an economic point of view.

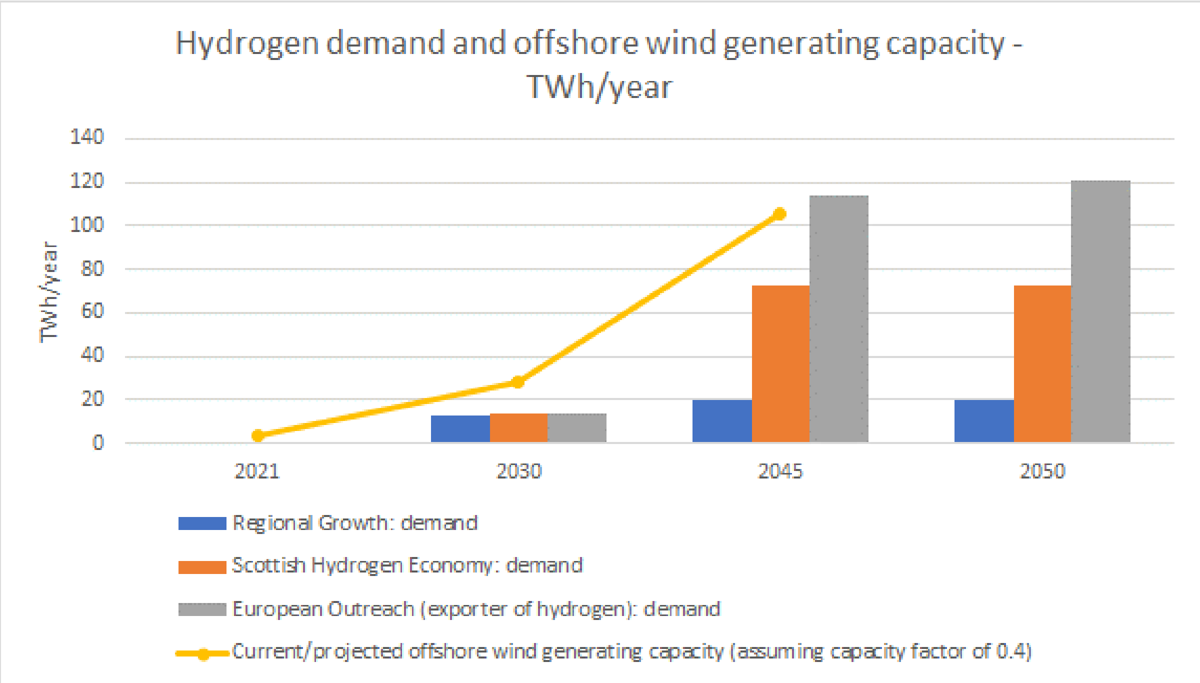


Figure 58. Expected hydrogen demand and offshore wind generating capacity. Sources:

- *Element energy: Hydrogen In Scotland The Role of Acorn Hydrogen in Enabling UK Net Zero;*
- *Offshore Wind Policy Statement Scottish Offshore Wind to Green Hydrogen Opportunity Assessment, and*
- *Offshore wind to green hydrogen: opportunity assessment - gov.scot (www.gov.scot).*

The Scottish Government has presented data that demonstrate the potential of OWF to contribute very significantly to the three hydrogen scenarios identified in its Hydrogen Policy Statement (see Figure 58 above). Depending on pricing of hydrogen, carbon pricing and cost of entry to the market, these figures demonstrate a significant untapped opportunity and a potential market for repurposed offshore infrastructure to host equipment.

When considered as part of a re-purposing scenario a number of economic issues must be overcome if an offshore re-purposing solution is to be achievable:

- The cost of addressing technical and safety challenges represent significant hurdles which need to be addressed before cost reductions can be achieved.
- Costs associated with a complete re-build of an offshore platform to create space and achieve structural reinforcement to accommodate new equipment will vary significantly, depending on individual circumstances.
- Onshore new build facilities are expected to offer significant cost savings over offshore solutions due to the proximity of generating plant to end user, and beyond. Other savings are expected to reflect the lower costs associated with logistics, labour rates and HSE risk management.

Where the cost of a re-purposed offshore installation is expected to exceed the cost of an equivalent new build or where the economics of a re-purposed offshore installation are not expected to compete with the economics of an onshore hydrogen production facility, proponents of repurposing existing infrastructure are advised to develop an economic model that permits a fuller project comparison. Such a model should be based on accounting sound practices, taking account of defined project boundaries, defined project life cycle systems and activities, direct and indirect costs, calculation methodology, carbon taxes and other environmental taxes and other influencing factors. The model should be developed as a joint industry initiative, and refined over time to reflect any cost savings attributable to the maturation of technological solutions, project management efficiencies and / or increase in carbon tax.

Regulatory framework

The findings of this study suggest that the UK benefits from a well-developed regulatory framework, experienced in the regulation of onshore and offshore sites with the potential for a major accident.

Knowledge of the existing regimes suggests that the regulations, codes and standards can readily be applied to assets repurposed to host offshore hydrogen generating equipment. e.g. DCR regulations intended for use in the offshore oil and gas industry have found application in the management of safety in the design of offshore substations.

These findings are in contrast to feedback received from many consultees, which suggested there are major gaps in the regulatory framework which are perceived as a significant barrier to further industrial development.

The gap between perception of stakeholders and the extent to which the regulatory regime addresses all hazards and risk factors associated with a repurposing scenario is not known. There is therefore a requirement to understand the similarities, differences, knowledge gaps and areas where knowledge transfer is possible between systems such as oil and gas safety cases, construction CDM arrangements, marine International Safety Management (ISM) codes and onshore Control of Major Accident Hazards (COMAH) regimes.

QHSE and asset management

Stakeholders consulted as part of this project identified the current offshore and onshore workforce as being ideally suited to support the repurposing of existing offshore infrastructure for hydrogen production. However, stakeholders raised concern that skills gaps existed that could affect the ability of an individual to adapt to new opportunities where knowledge and experience of hydrogen safety and technical issues are critical. Understanding skills gap between existing arrangements for the management of offshore and onshore major accident hazards with respect to hydrogen is of particular importance.

UK content

Stakeholders consulted as part of this project identified the current offshore and onshore workforce as being ideally suited to support the repurposing of existing offshore infrastructure for hydrogen production. However, stakeholders raised concern that skills gaps existed that could affect the ability of an individual to adapt to new opportunities where knowledge and experience of hydrogen safety and technical issues are critical.

This study has highlighted the lack of an electrolyser manufacturer in Scotland to take advantage of the expected growth in commercial demand for the equipment in the domestic market and more widely. Addressing this deficit should be regarded by policy makers as a priority item for consideration.

Decommissioning

This study has identified clear synergies with the late life management and decommissioning of offshore oil and gas infrastructure.

- Scotland benefits from having a number of suitably sized yards and supply chain contractors experienced in all elements of decommissioning and recycling;
- The yards are ideally located in relative proximity to end of life assets or retrofit candidates to take advantage of an emerging market for the repurposing of offshore infrastructure;
- Notwithstanding the positive attributes, it must be recognised that decommissioning presents a number of conflict scenarios such as continued availability of infrastructure before it is decommissioned. Repurposing may also be seen as a driver for deferral.

10.3. Recommendations

It is recommended that further work be conducted to:

1. Further refine costs models, consistent with advances in our understanding of safety and technical risk management to help drive down costs;
2. Better understand benchmark costs for the removal of major components such as topsides module(s) from "donor" platforms;
3. Better understand financial liabilities associated with the repurposing of existing installations which are in late life or would otherwise be decommissioned;
4. Consider cost of onshore new build facilities as these have not been assessed within this study;
5. Better understand the potential for reuse of recycled material; this is the focus of the NexStep initiative in the Netherlands;
6. Expand decommissioning guidance to highlight potential re-use options for hydrogen production and other power generation scenarios to ensure all alternatives are considered in detail;
7. Define mechanisms for the transfer of liability, noting that this could be particularly complicated where candidate infrastructure is one part of an asset e.g. one pipeline on an asset out of a possible six exiting the structure;
8. Consider full integration of hydrogen alongside CCS / CCUS;
9. Consider the price of carbon as an influencing factor in the success of the hydrogen economy and a low carbon economy. In this context, consideration should be given to further development of carbon pricing and taxation schemes to encourage transition to net zero;
10. Better understand regulator roles and responsibilities, regulations, codes and standards in order to confirm adequacy of existing arrangements, identify gaps and the potential for transfer from one application to another. In particular, where there is a difference in the perception of stakeholders and the extent to which the regulatory regime addresses all hazards and risk factors associated with a repurposing scenario, there is a requirement to understand the similarities, differences, knowledge gaps, and to identify areas where knowledge transfer between regulatory regimes is possible.
11. Review management arrangements to understand the similarities, differences, knowledge gaps and areas where knowledge transfer is possible between HSE management systems.
12. Understand the skills gap between existing arrangements for the management of offshore and onshore major accident hazards with respect to hydrogen.
13. Fully understand the contribution gas to graphene can make to the economics of hydrogen generation, in the context of repurposing of existing offshore installations.

14. Review challenges associated with the repurposing of available pipelines for pure hydrogen and hydrogen / methane blends to understand, economic uncertainties associated with the condition of redundant pipelines, corrosion and integrity issues associated with hydrogen transportation duties, physical and chemical differences between hydrogen and natural gas (methane) and concerns regarding stress cracking; and pipeline availability / compatibility with decommissioning plans.
15. Address the lack of an electrolyser manufacturer in Scotland to take advantage of the expected growth in commercial demand for the equipment in repurposing and new build projects.
16. Realise the potential of SMR as a net zero enabler; there is a need to consider the linkage between offshore application of the technology and the road to a low carbon future.
17. Realise the potential of gas to graphene technology in the context of a net zero operating strategy.
18. Develop an economic cost model to allow a comprehensive comparison of hydrogen generation projects based on the use of re-purposed infrastructure, new build and an onshore hydrogen production facility. The model should be developed as a joint industry initiative.

10.4. Prioritisation of recommendations arising

For the purposes of prioritisation, we have used the data derived from our analysis of risks and opportunities to assign priorities to general groups. The graphical representation of the data identifies priority elements according to level of maturity (where low number signifies low level of maturity and implies a higher level of effort to realise market potential). Importantly, the graph is not intended to suggest an order in which actions should be scheduled. Prioritisation decisions on how, or when to address “low hanging fruit” or the more demanding issues should be agreed in consultation with stakeholders.

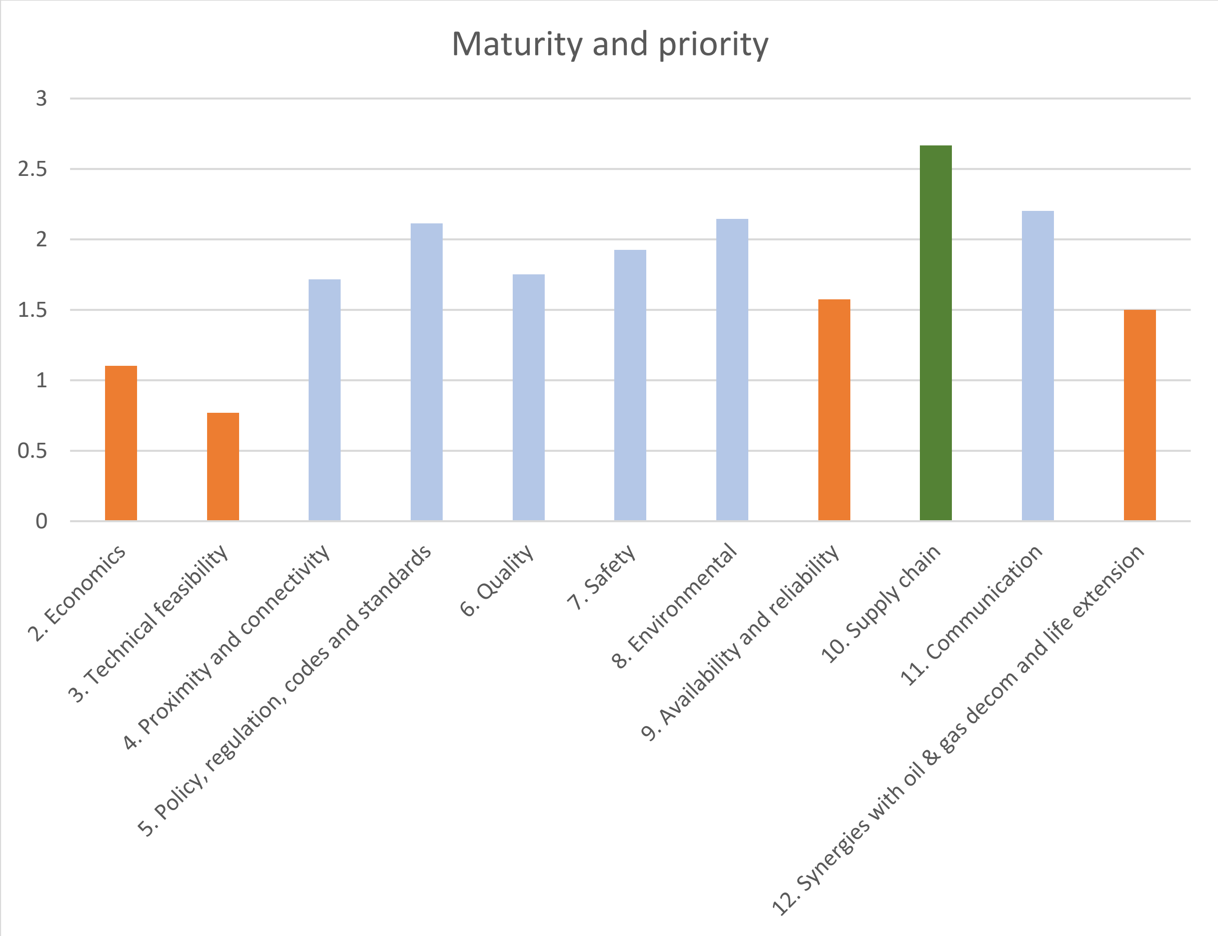


Figure 59. Maturity and priority.

Priority group 1

Those elements associated with the repurposing agenda seen to be least mature, and therefore regarded as being priority items for further development are the related areas of economics and technical feasibility.

The availability and reliability of plant and equipment should also be considered in this context. That is, the availability and reliability of equipment and plant associated with constant supply of renewable energy from offshore wind farms; storage capacity for hydrogen and CO2; use of raw seawater and corrosion; remaining life span of infrastructure from sea-bed to surface.

Priority group 2

Elements regarded as being relatively mature have their origins in the oil and gas industry, and have been developed over a period of 40 years. These elements are:

- Proximity of candidate infrastructure to hydrogen demand centres, generation locations and the supply chain; and
- Organisational and management elements associated with policy, regulation, QHSE and communication; and
- Synergies with oil and gas decommissioning and asset life extension;

Priority group 3

The supply chain category accounts for local workforce and international networks in terms of supply bases, port facilities, marine operations, aviation, project management, engineering and more. In common with the elements of priority group 2, the maturity and ability of this cohort to be re-purposed towards an offshore hydrogen economy has its genesis in over 40 years oil and gas experience.

Appendix A Glossary/abbreviations

Figure 60. Glossary of terms and abbreviations used in this report.

Acronym	
ABEX	Abandonment Expenditure
AC-DC	Alternating Current-Direct Current
AE	Alkaline Electrolyser
AEC	Alkaline Electrolysis Cell
AFE	Authority for Expenditure
API	American Petroleum Institute
APPEA	The Australian Petroleum Production & Exploration Association (APPEA)
BEIS	Department for Business, Energy & Industrial Strategy
CAPEX	Capital Expenditure.
CDM	Construction Design and Management
CCS	Carbon Capture and Storage
CCU	Carbon Capture Unit
CCUS	Carbon Capture, Usage and Storage
CNS	Central North Sea
COMAH	Control of Major Accident Hazards
CO_2	Carbon Dioxide
CoP	Cessation of Production
COP	Code of Practice
DCR	The Offshore Installations and Wells (Design and Construction, etc.) Regulations
DP	Decommissioning Plan
DTU	Department of Energy Conversion and Storage Technical University of Denmark
EC	European Commission
EEZ	Exclusive Economic Zone
EIA	Environmental Impact Assessment
EPC	Engineering, Procurement and Construction
ESDV	Emergency Shut Down Valve
EU	European Union
EUR	Euro
FCH	The Fuel Cells and Hydrogen Joint Undertaking
FEED	Front End Engineering Design
FID	Final Investment Decision
FPSO	Floating Production, Storage and Offloading
ft	Foot (imperial)

G&A	General and Administrative
GBP	United Kingdom Pound Sterling
GBS	Gravity based structure
GVA	Gross Value Added
H&S	Health and Safety
HSE	Health and Safety Executive
HSSEQ	Health, Safety, Security, Environment and Quality
ISO	International Organization for Standardization
JRC	Joint Research Centre (JRC) EU Science Hub
kg	Kilogram
KPI	Key Performance Indicator.
LSA	Low Specific Activity
LR	Lloyd's Register
m^2	Square Metre
MCA	Maritime and Coastguard Agency
MER	Maximising Economic Recovery
ML	Marine License
MM	Million
MODU	Mobile Offshore Drilling Unit
MRFG	Marine Renewables Facilitators Group
MS-LOT	Marine Scotland Licensing Operations Team
MW	Mega watt
MWth	Mega watt thermal
NLB	Northern Lighthouse Board
NM	Nautical Miles
Nm^3	Normal cubic metres
NNS	Northern North Sea
NOPSEMA	The National Offshore Petroleum Safety and Environmental Management Authority
NORM	Naturally occurring radioactive material
NUIs	Normally Unmanned Installations
OGA	Oil and Gas Authority
OGTC	Oil & Gas Technology Centre
O&M	Operation and Maintenance
OEM	Original Equipment Manufacturer
OPEX	Operating Expenditure
OPRED	Offshore Petroleum Regulator for Environment and Decommissioning
OSDR	Offshore Safety Directive Regulator
OWF	Offshore Wind Farm
PEM	PEM Electrolysers (Proton / Polymer Exchange Membranes)
PLANC	Permits, Licenses, Authorisations, Notifications and Consents
PPC	Pollution Prevention and Control
PSR	Pipeline Safety Regulations

SCR	Safety Case Regulations
SEPA	Scottish Environment Protection Agency
SMR	Steam Methane Reforming
SNH	Scottish Natural Heritage
SNS	Southern North Sea
SOEC	Solid Oxide Electrolysis Cell
SOWEC	Scottish Offshore Wind Energy Council
SPM	Single Point Mooring
SPMT	Self-Propelled Modular Transporters
SSE	Scottish and Southern Energy
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
USA	United Sates of America
VAT	Value Added Tax
WTG	Wind Turbine Generator

Appendix B Table of figures

Figure 61. Table of figures

Appendix C List of infrastructure and equipment associated with the manufacture and transportation of hydrogen

Figure 62. List of infrastructure and equipment associated with the manufacture and transportation of hydrogen.

Infrastructure and equipment associated with the manufacture and transportation of hydrogen.
Offshore upstream generation of hydrogen.
H2 generation technology
Wind Turbine Generator (WTG)
Electrolysers
Oil and gas structures (Fixed and floating installations)
Central Offshore Vessel for Electrolysis
Sub-structure (offshore structure)
AC-DC Rectification (substation - substructure)
Ancillary equipment associated with O&G structure and / or required for H2 generation
Mooring and Anchors
Power, electric and cabling
AC-DC Rectification (Substation electrical equipment)
AC-DC Rectification (Substation Sub Structure)
Export Transmission - Electricity (cabling)
Inter-array Cabling
Power cable from beach.
Disused sewage pipe for cable dune crossing.
Electrical system
Stand-by Power - Diesel generator
Health & safety and communications networks.
Risers, seawater lift and de salination
Desalination
Seawater Lift/ Sea water pumps
Risers and Gathering
Water maker RO unit.

Export and compression
Export Compression and Pipeline infrastructure to shore.
Export compression and pipeline to neighbouring platform as fuel gas.
Compressors
Graphene offtake and shuttle to shore
Ship based hydrogen export - Liquid hydrogen
Ship based hydrogen export - Ammonia
Ship based hydrogen export - Liquid Organic Hydrogen (Methyl Cyclohexane (MCH), Di-benzyltoluene, N-ethylcarbazole, Di-cyclohexylmethane)
20 Ship based hydrogen export - Compressed Hydrogen
Processing
Liquefiers & post-processing
Tube trailers and storage tanks
Feed gas from pipeline or host asset
Flare gas from production asset
Gas from nearby asset / stranded asset / well
New gas import pipeline
Hydrogen and CO2 storage
Subsurface Hydrogen Storage - Salt caverns
Subsurface Hydrogen Storage - Depleted oil and gas fields
Subsurface Hydrogen Storage - Aquifers
Subsurface Hydrogen Storage - Conventionally mined rock caverns
Gas storage - disused pipelines
New Hydrogen Export Pipeline
CO2 storage
Onshore - processing, port handling, terminal and onward transport
Port installation - Hydrogen handling port services.
Ports infrastructure to support offshore O&M
Offshore logistics
Surface transport delivery
Onshore logistics (Transport of hydrogen logistics - road transport)
Onshore Electrolysis Buildings
Onshore gas plant
Mattresses
Tubulars

Appendix D References

Figure 63. List of references used in the report.

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Appendix E Study tasks

Activities / study areas required to address the work scope

Activities / study areas identified by SOWEC and Crown Estate Scotland for study are reproduced in this section.

1. The study shall provide an overview of the following areas:

   a) Development and consenting processes for commercial scale offshore green and blue hydrogen production (activity / study area 1);
   b) Availability and suitability of electrolyser technologies for offshore hydrogen production (activity / study area 2);
   c) Fundamental approach to best use of existing infrastructure including transmission lines, and platforms for generation and transmission (activity / study area 3);
   d) Cost estimation for key enabling Hydrogen Supply Chain capability and infrastructure, electrolyser supply, port and quayside infrastructure, reinforced quayside areas (with services), operation and maintenance marine and quayside operations (Activity / study areas 4).

2. The study shall:

   a) Include a cost comparison, and benefit analysis of onshore vs offshore hydrogen production (Activity / study area 5);
   b) Identify and assess generic “risks” that a project developer may be expected to negotiate. Scope shall include uncertainties around the project delivery process, programme of works, cost, knowledge gaps, interests of key stakeholders and statutory consultees (Activity / study area 6);
   c) Identify, assess and rank mitigation measures to the risks identified in the risk assessment stage of the assessment (Activity / study area 7);
   d) Identify generic opportunities from this study for a project developer to benefit in terms of the project delivery process, UK strategic programme for offshore hydrogen and repurposing of existing infrastructure; cost management; industry knowledge; views of statutory consultees).

3. Where opportunities are identified as a result of this review process, they shall be scored according to priority (high, medium, low). Scoring shall reflect:

   a) Capacity of the industry to make use of repurposed infrastructure to deliver a strong pipeline of hydrogen projects from late 2020s to 2050;
   b) Consideration of desired UK content targets (including where relevant Scottish Government ambition for local content in ScotWind projects), as regards maximising the economic benefit to Scotland;
   c) Consideration of Industry demand in likely hydrogen clusters (geographical and supply chain); and
   d) Prioritised recommendations for further work, consistent with SOWEC Energy Transition vision (An offshore wind sector that plays to Scotland’s strengths, delivering jobs, investment and export opportunities in line with the UK Sector Deal as a key part of the path to net zero).

Appendix F Full page maps

Existing oil and gas infrastructure.

Figure 64. Infrastructure pipelines and licenced blocks. Source; OGA Offshore interactive map, current.
https://www.arcgis.com/apps/webappviewer/index.html?id=adbe5a796f5c41c68fc762ea137a682e

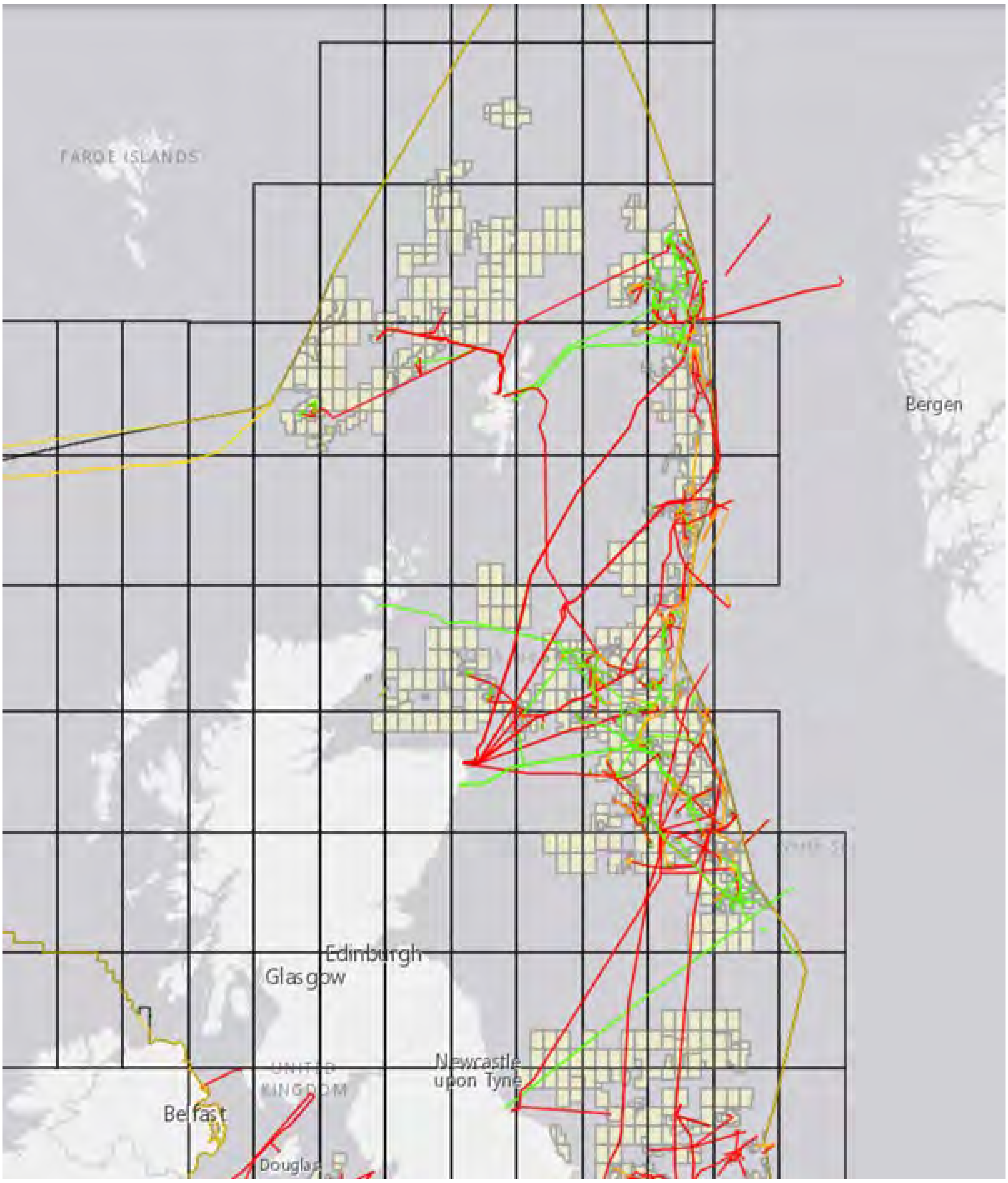

Figure 65. Surface infrastructure and licenced blocks. Source ; OGA Offshore interactive map, current https://www.arcgis.com/apps/webappviewer/index.html?id=adbe5a796f5c41c68fc762ea137a682e

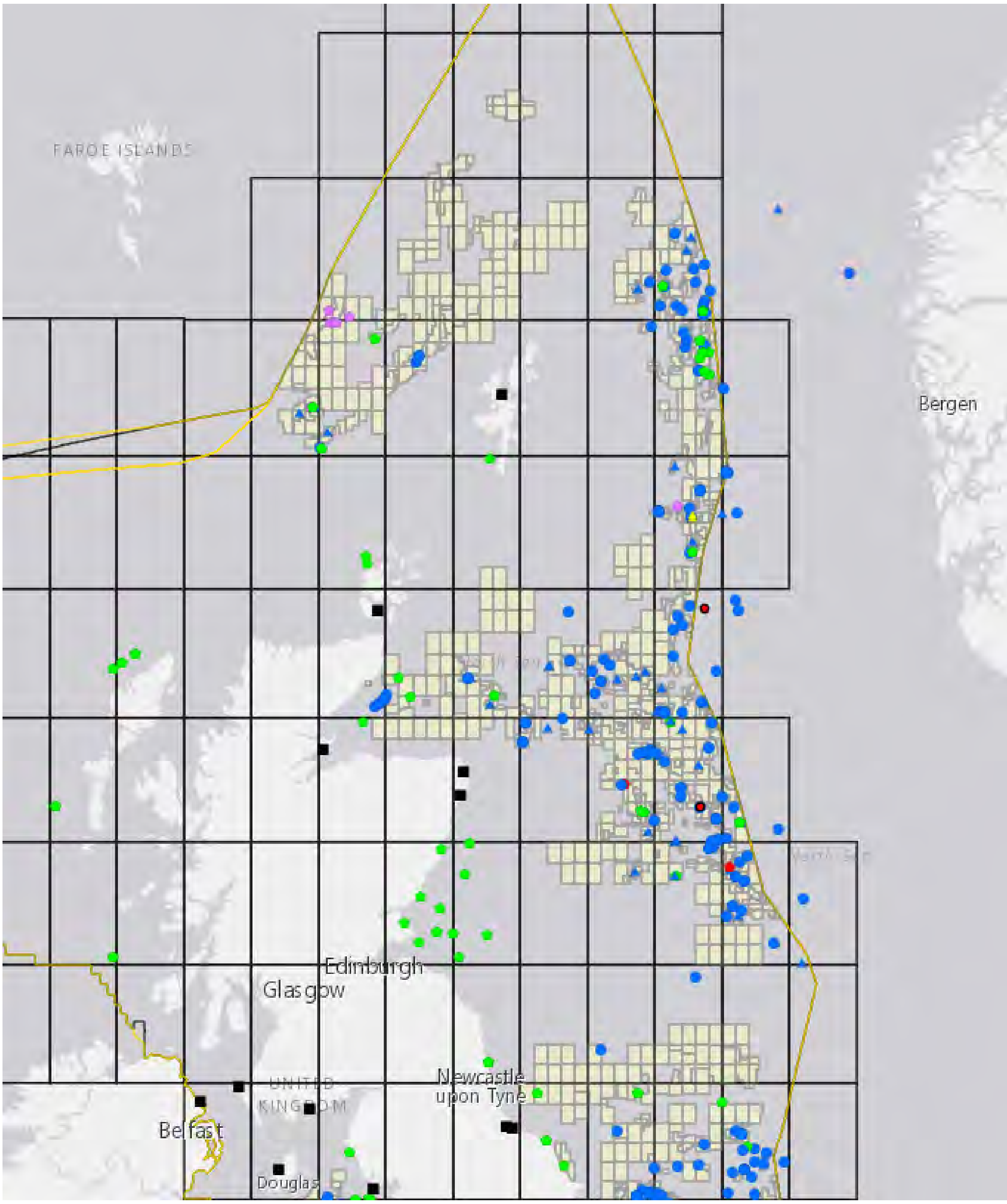

Figure 66. Subsurface infrastructure and licenced blocks. Source ; OGA Offshore interactive map, current.

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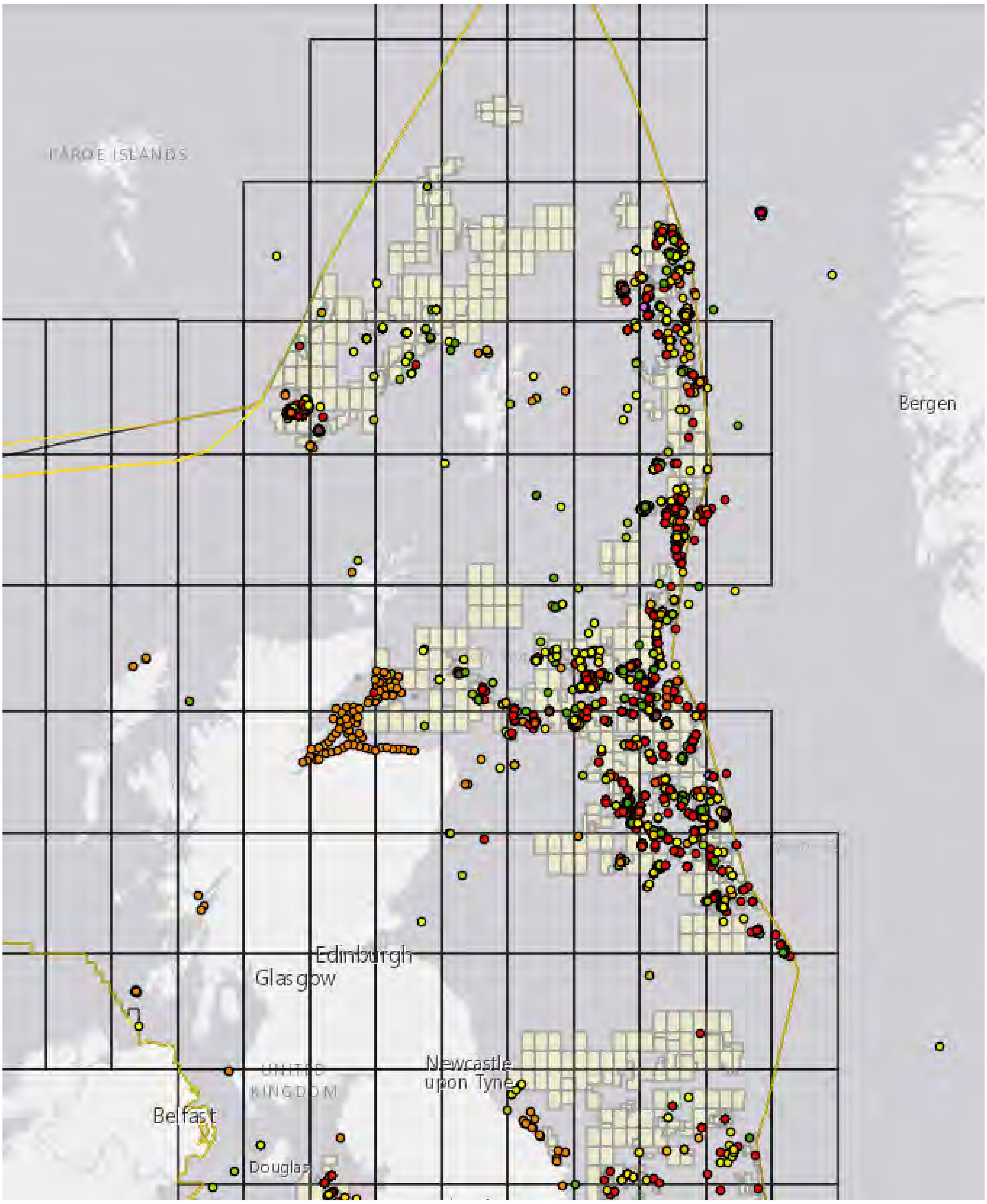


Windfarm leases and developments.

Figure 67. Offshore wind farm infrastructure. Source; Marine Scotland, Sectoral Marine Plan (SMP) - Wind (Offshore) Plan Options, October 2020).

https://marinescotland.atkinsgeospatial.com/nmpi/default.aspx?layers=1892

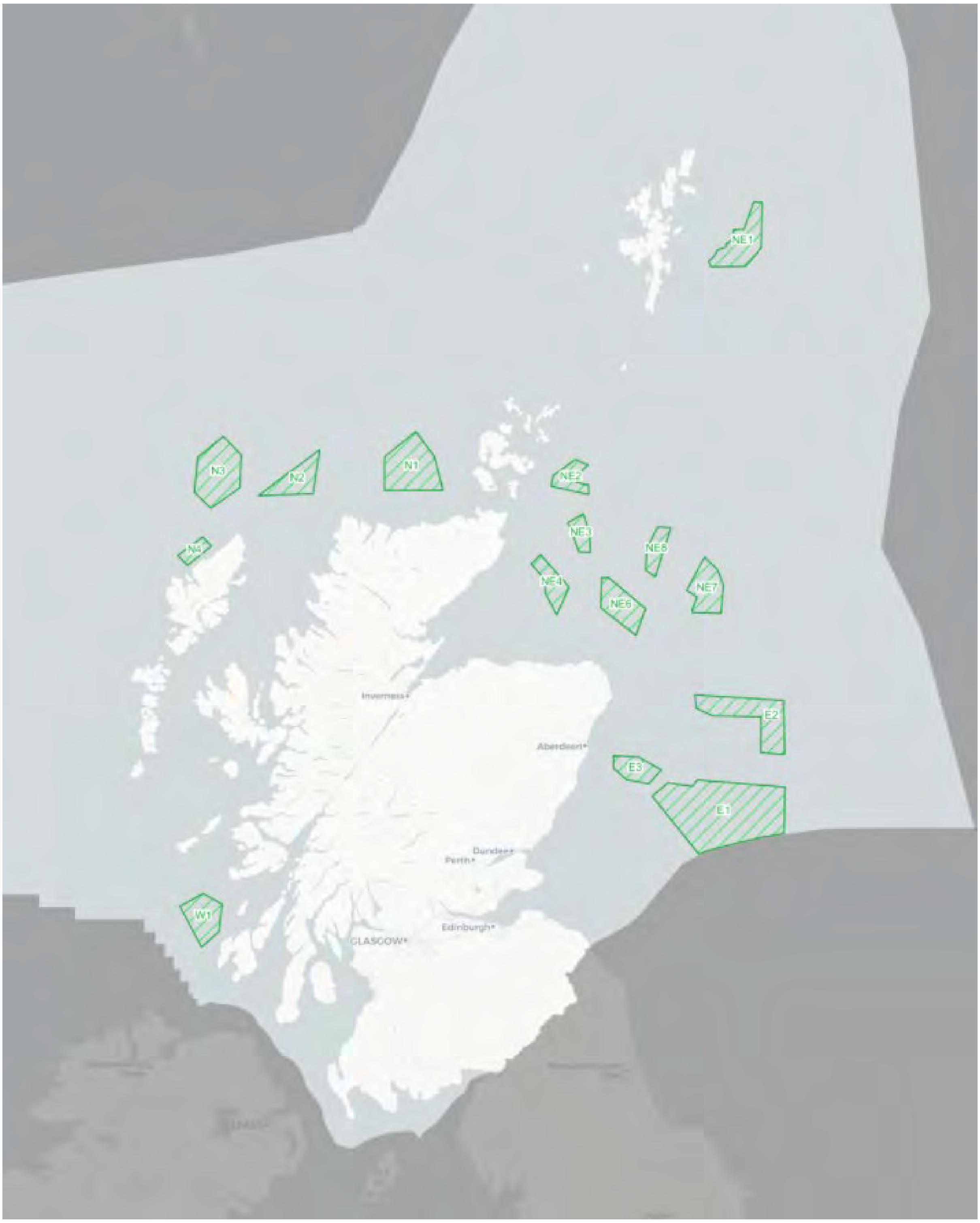


Figure 68. Offshore wind plan options and current offshore wind developments. Source; Scottish Government, Sectoral marine plan for offshore wind energy. https://www.gov.scot/publications/sectoral-marine-plan-offshore-wind-energy/

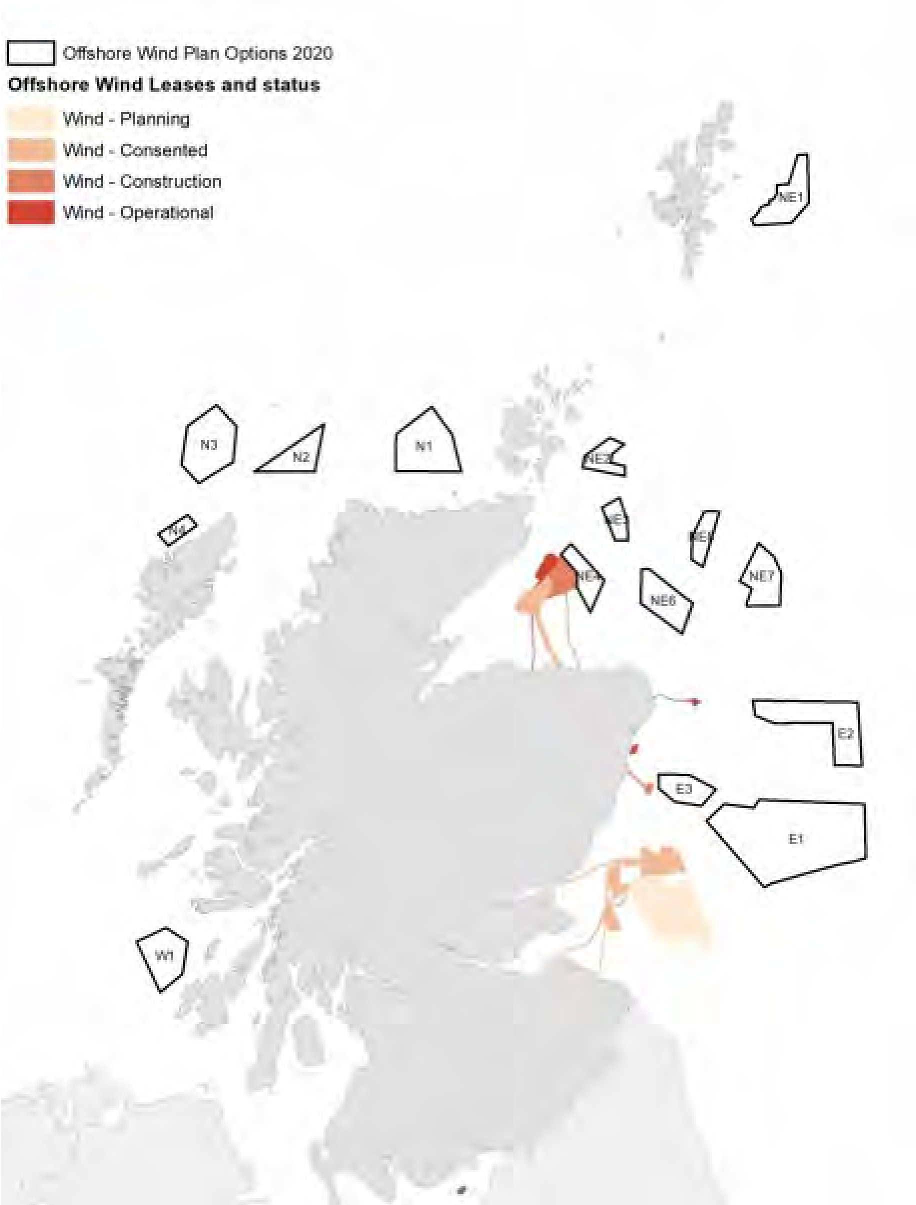
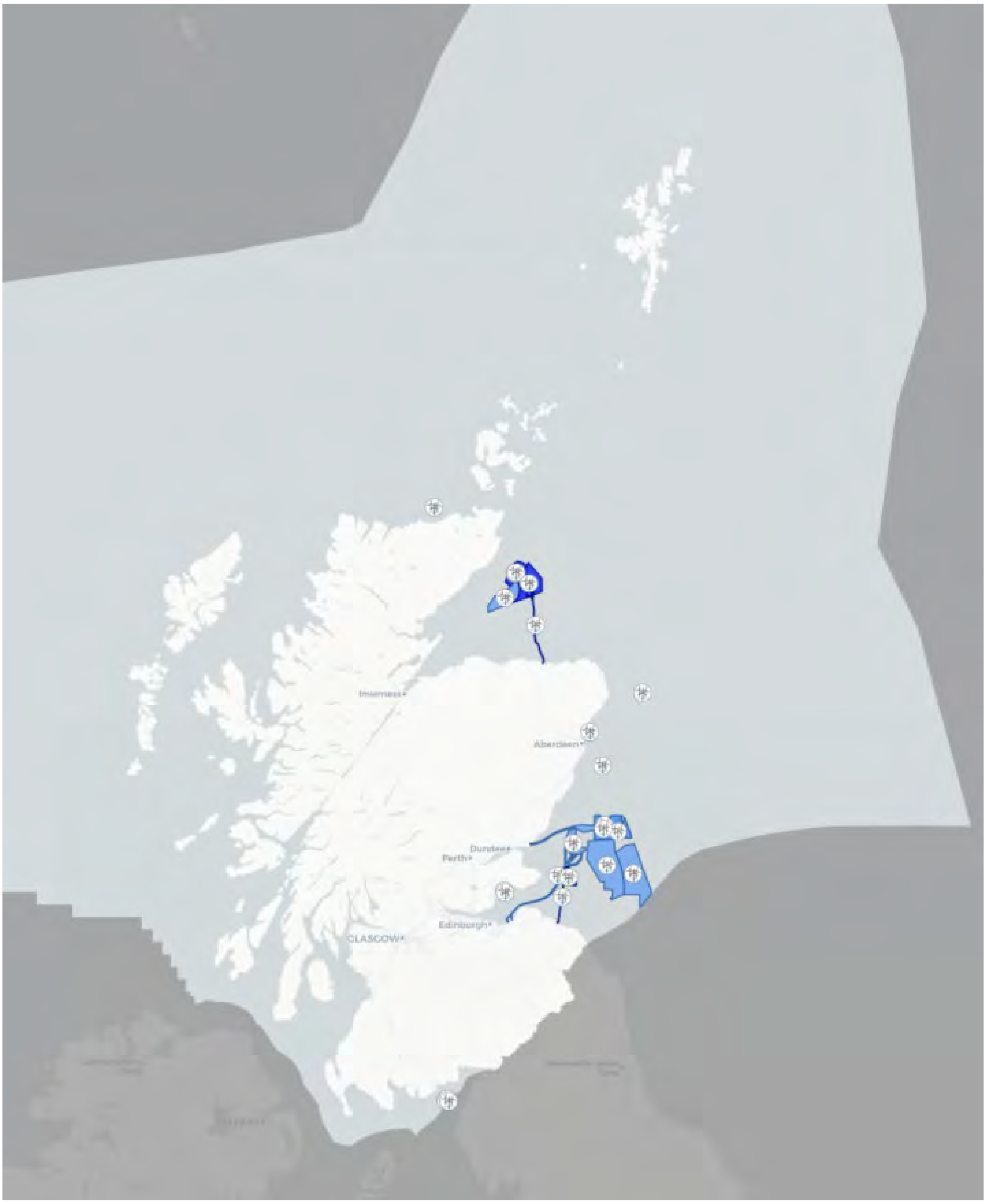


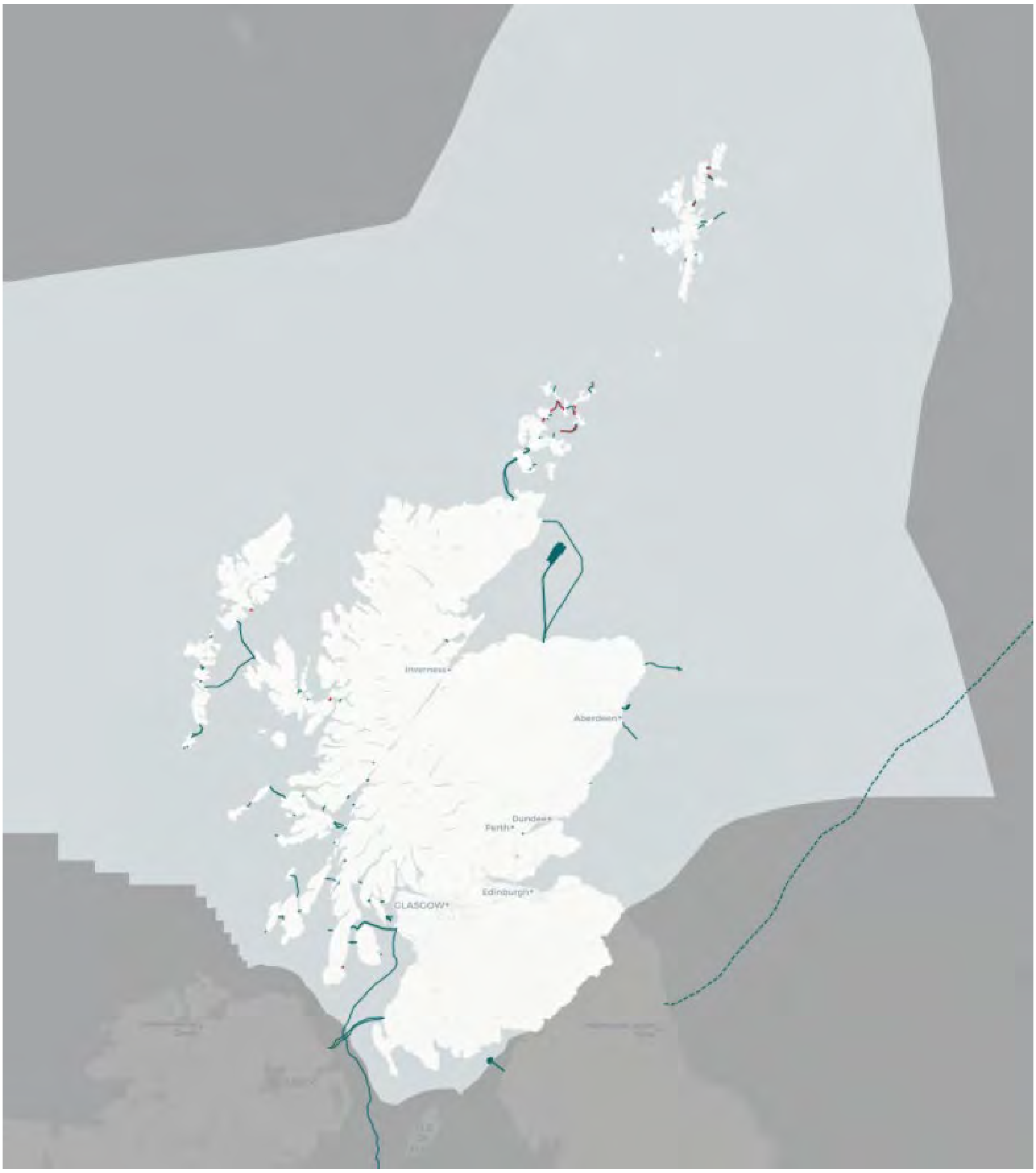
Figure 69. Proximity to existing Crown Estate Scotland Wind Lease Sites, at 2020-05-21. Source; Crown Estate Scotland, Wind Lease Sites – May 2020.
https://marinescotland.atkinsgeospatial.com/nmpi/default.aspx?layers=1555

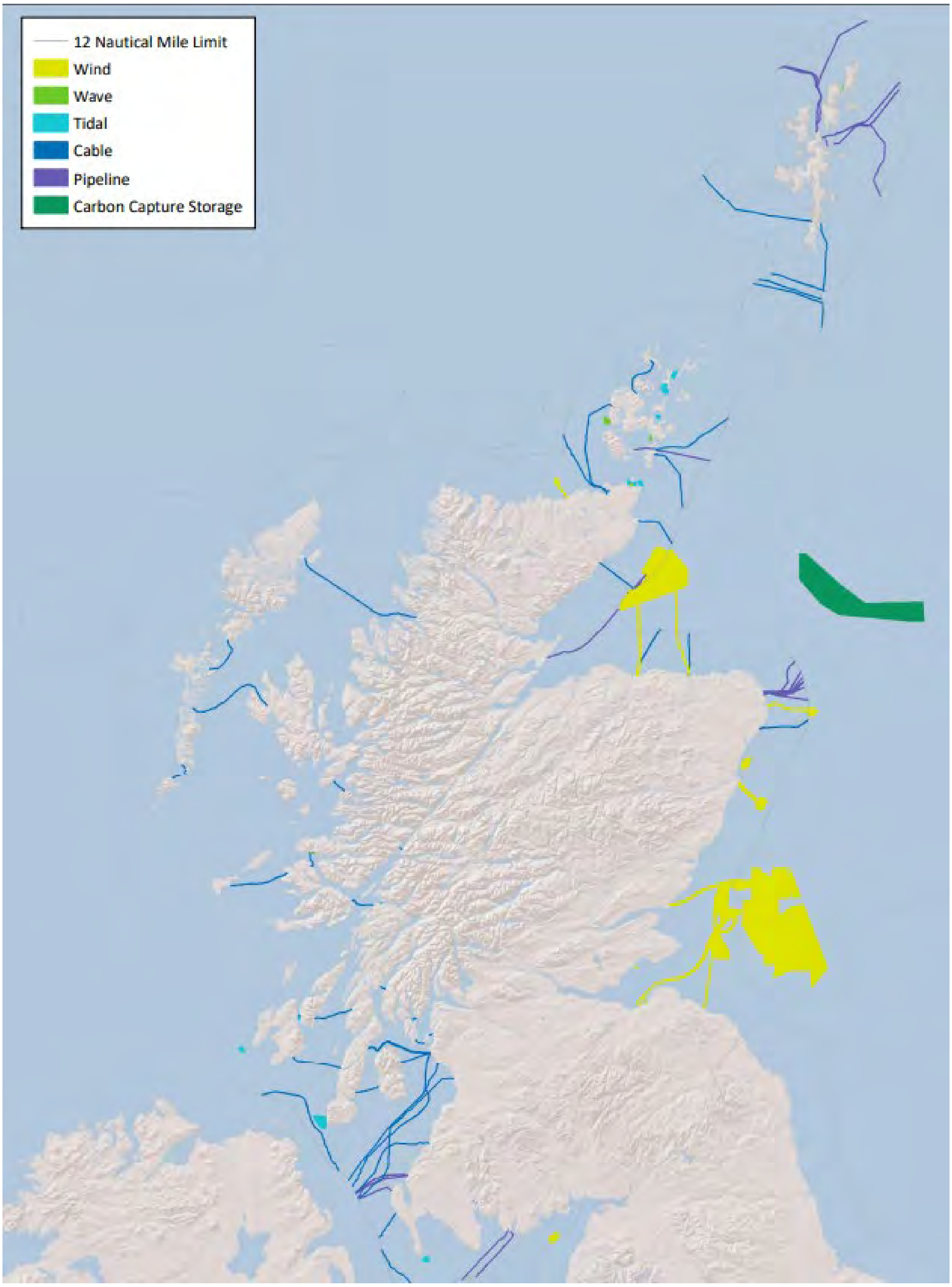


Power cable routes.

Proximity of power cables to hydrogen generation hubs.

Figure 70. Renewable energy and power cable infrastructure. Source ; Marine Scotland, Power Cables (KIS-ORCA), January 2020.
[*https://marinescotland.atkinsgeospatial.com/nmpi/default.aspx?layers=443*](https://marinescotland.atkinsgeospatial.com/nmpi/default.aspx?layers=443)





Relative proximity of renewable energy developments to cables, pipelines and CCUS activity

Figure 71. Composite view, offshore renewable energy projects and cable and pipelines as at 21/05/2020. Source; Offshore renewables, cables and pipeline activity, May 2020. [*https://www.crownestatescotland.com/maps-and-publications*](https://www.crownestatescotland.com/maps-and-publications)

CCUS locations.

Proximity of carbon capture and storage projects to hydrogen generation hubs.

Figure 72. Proximity to CCUS saline aquifer areas. Source ; Marine Scotland, Carbon Capture and Storage - Saline Aquifer Areas, January 2009.
https://marinescotland.atkinsgeospatial.com/nmpi/default.aspx?layers=514

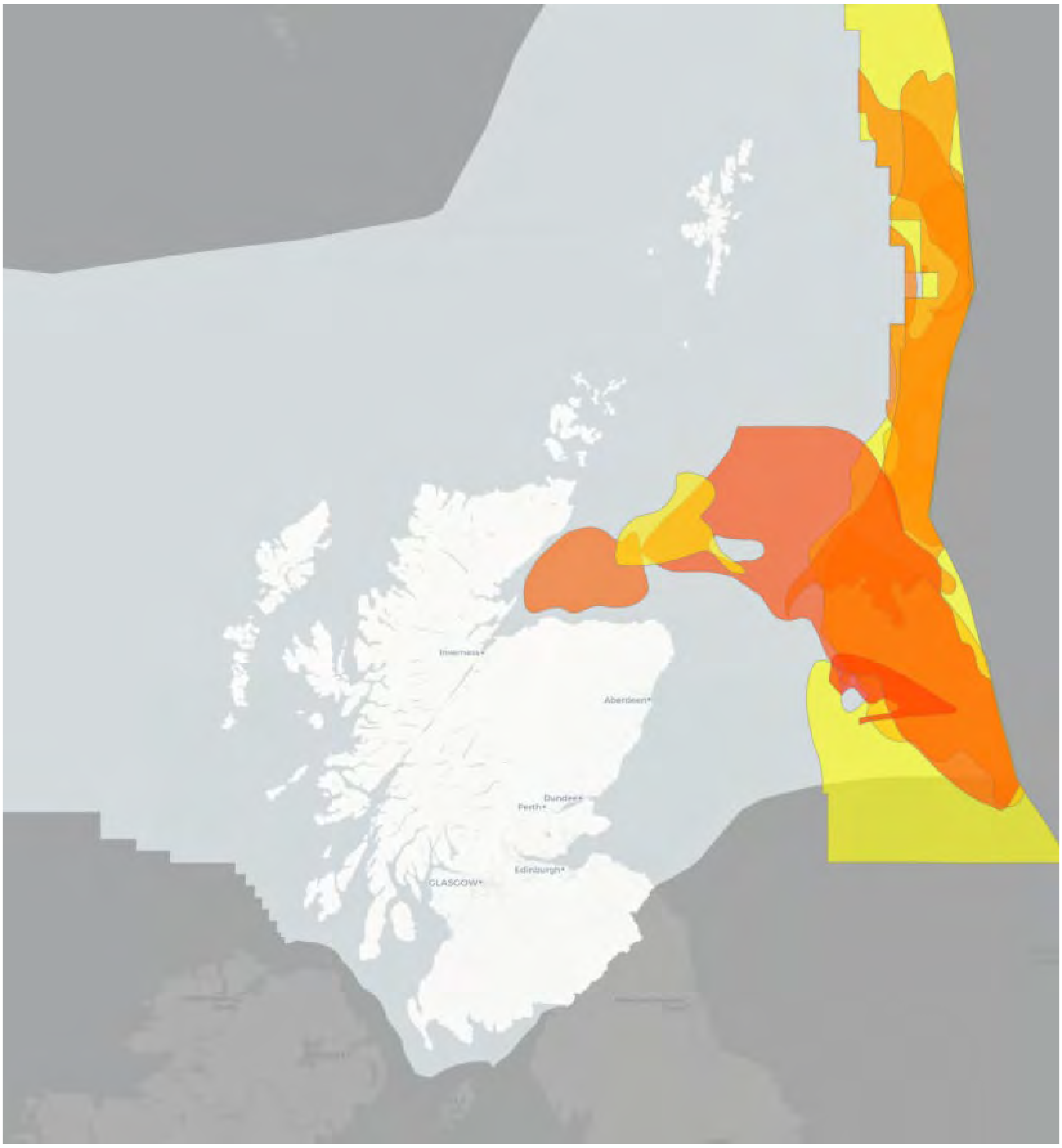


Figure 73. Proximity to CCUS saline aquifer sites. Source ; Marine Scotland, Carbon Capture and Storage - Saline Aquifer Sites, January 2009.
https://marinescotland.atkinsgeospatial.com/nmpi/default.aspx?layers=513

Figure 74. Scottish Ports and Proximity to UKCS Fields. Source; Scottish Enterprise, Highlands and Islands Enterprise, Scottish Development International, Oil and gas decommissioning capability, 2018.

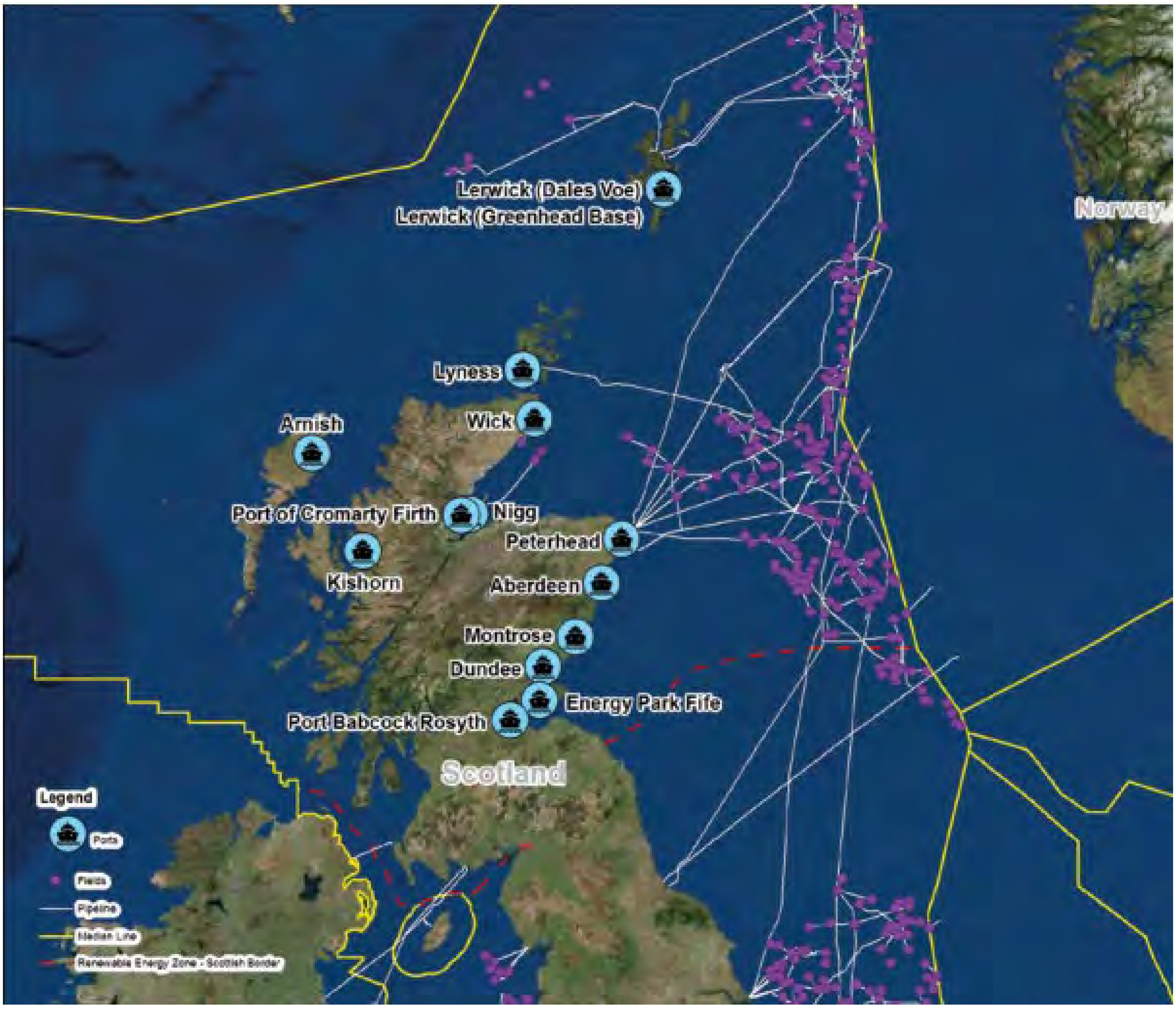


Figure 75. Ports meeting hard criteria for Marshalling & Assembly associated with large construction-phase requirements.

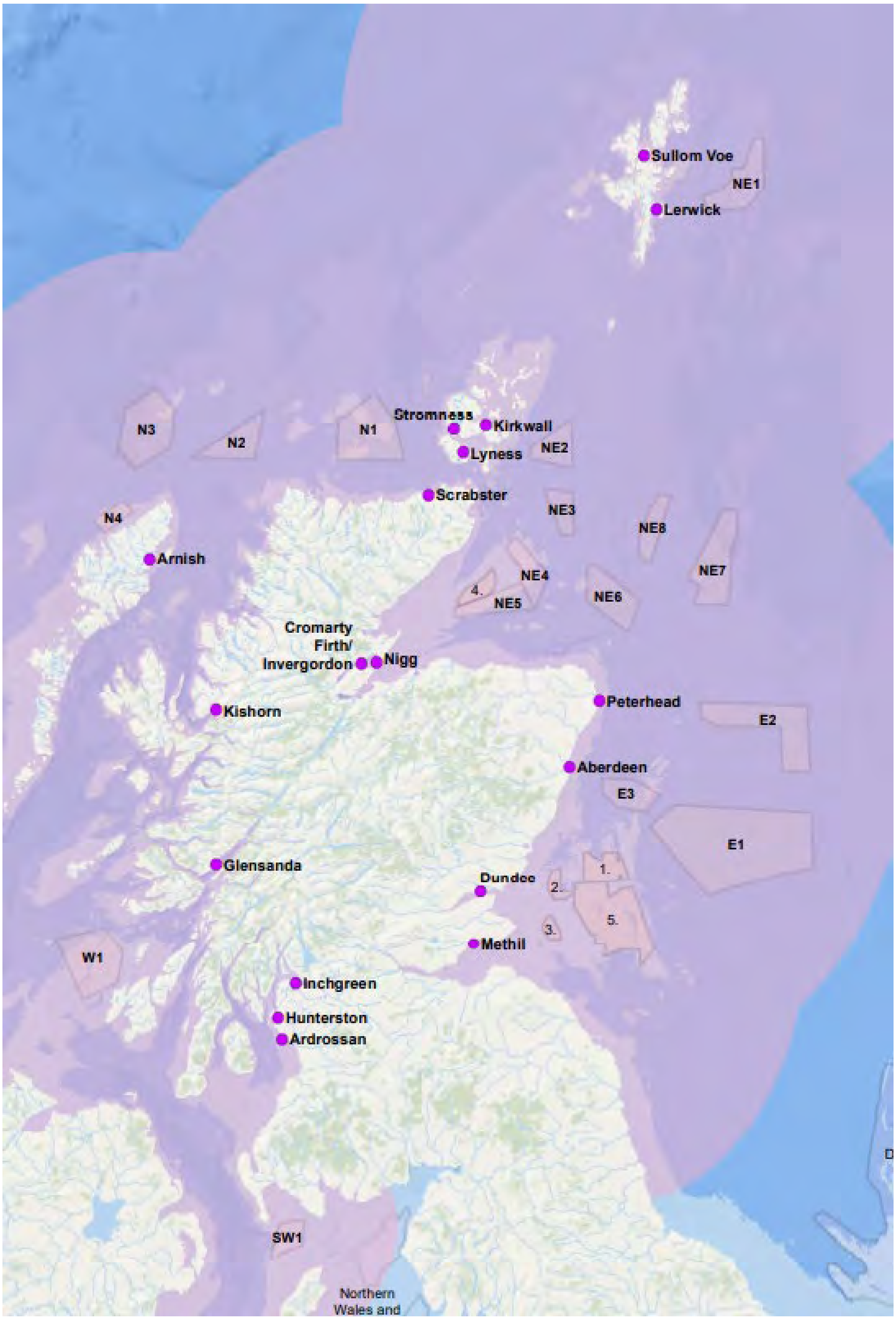


Figure 76. Ports meeting hard criteria for Fabrication & Manufacturing associated with large construction-phase requirements.

Figure 77. Composite view of existing oil and gas infrastructure. Source; https://www.ogauthority.co.uk/the-move-to-net-zero/interactive-energy-map-for-the-ukcs/

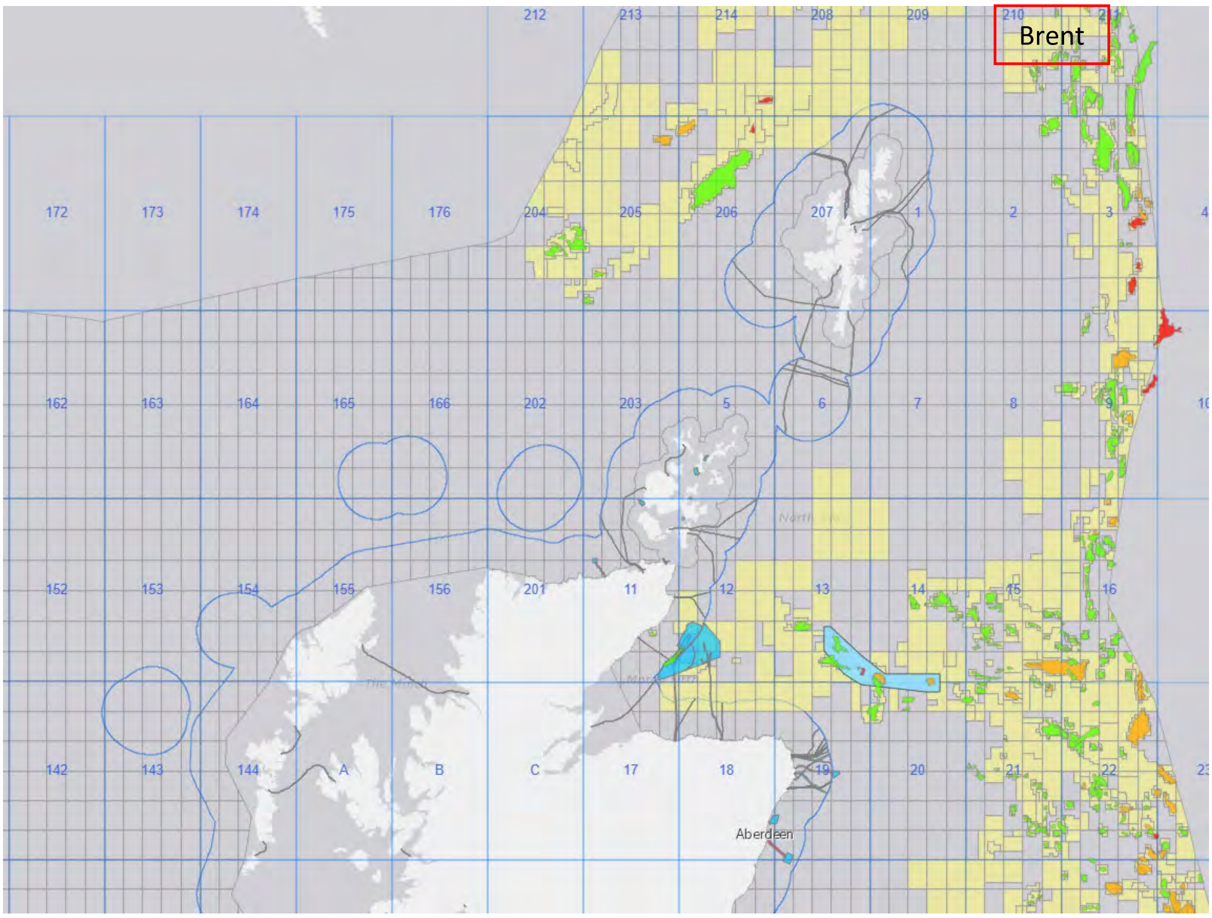
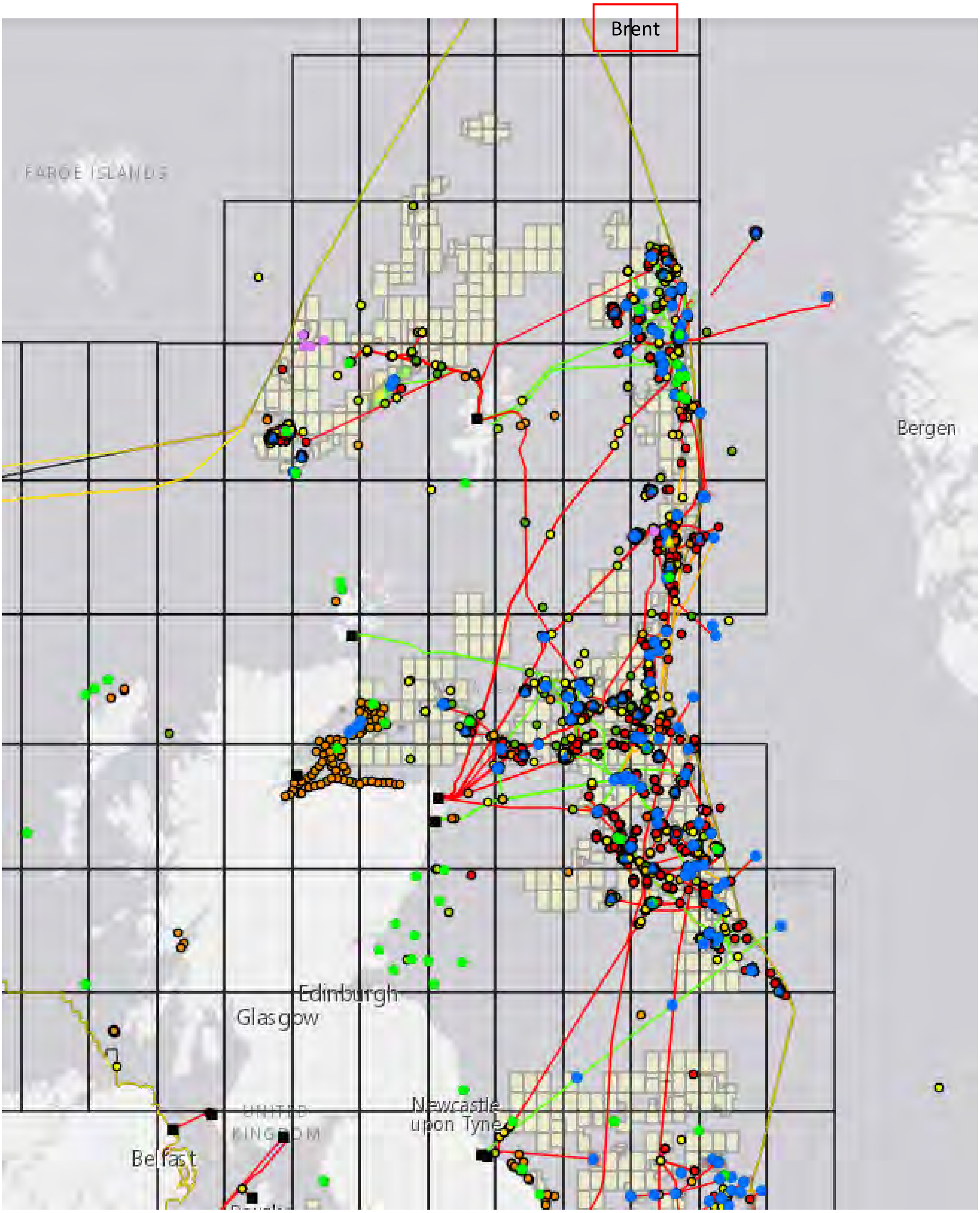
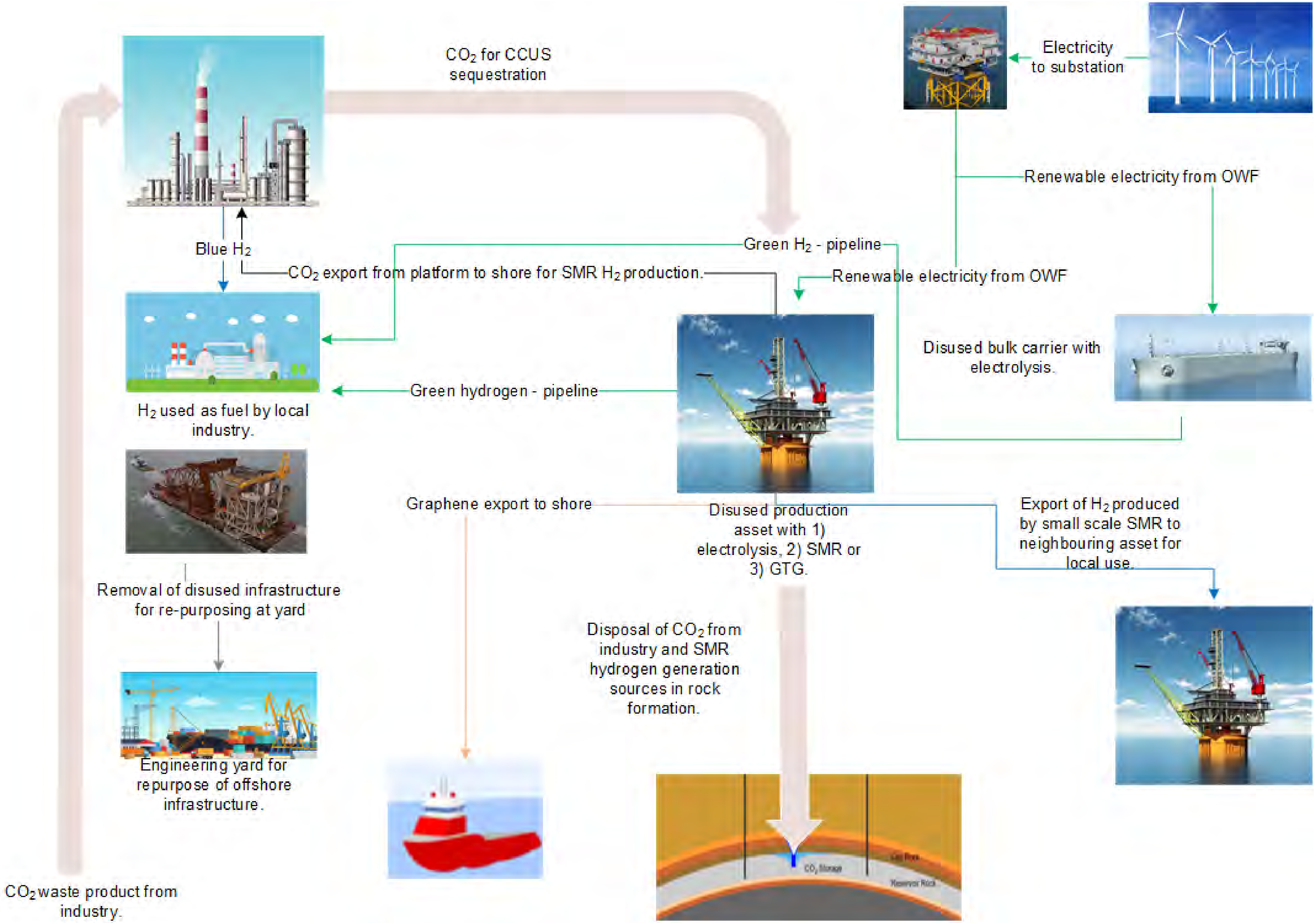


Figure 78. Composite view of existing oil and gas infrastructure. Source; OGA Offshore interactive map, current.
https://www.arcgis.com/apps/webappviewer/index.html?id=adbe5a796f5c41c68fc762ea137a682e



Appendix G Activities associated with the repurpose of oil and gas infrastructure

Figure 79. Diagram summarising scope of activities and actors associated with the repurpose of oil and gas infrastructure for the production of hydrogen subject to regulation



CO$_2$ for CCUS sequestration
Electricity to substation
Renewable electricity from OWF
Blue H$_2$
Green H$_2$ - pipeline
CO$_2$ export from platform to shore for SMR H$_2$ production.
Renewable electricity from OWF
Disused bulk carrier with electrolysis.
Green hydrogen - pipeline
H$_2$ used as fuel by local industry.
Graphene export to shore
Disused production asset with 1) electrolysis, 2) SMR or 3) GTG.
Export of H$_2$ produced by small scale SMR to neighbouring asset for local use.
Removal of disused infrastructure for re-purposing at yard
Disposal of CO$_2$ from industry and SMR hydrogen generation sources in rock formation.
Engineering yard for repurpose of offshore infrastructure.
CO$_2$ waste product from industry.

Appendix H Codes and standards

Figure 80. Codes and standards cited in the report.

Group	Documents	Scope
International Standards Organisation (ISO) - Technical Committee : ISO/TC 197 Hydrogen technologies.	ISO/TR 15916:2015, Basic considerations for the safety of hydrogen systems	Replaces ISO/TR 15916 : 2004. SO/TR 15916:2015 provides guidelines for the use of hydrogen in its gaseous and liquid forms as well as its storage in either of these or other forms (hydrides). It identifies the basic safety concerns, hazards and risks, and describes the properties of hydrogen that are relevant to safety. Detailed safety requirements associated with specific hydrogen applications are treated in separate International Standards.
International Standards Organisation (ISO) - Technical Committee : ISO/TC 197 Hydrogen technologies.	ISO 22734:2019, Hydrogen generators using water electrolysis — Industrial, commercial, and residential applications.	Under development, stage 20.00. This document defines the construction, safety, and performance requirements of modular or factory-matched hydrogen gas generation appliances, herein referred to as hydrogen generators, using electrochemical reactions to electrolyse water to produce hydrogen. This document is applicable to hydrogen generators intended for industrial and commercial uses, and indoor and outdoor residential use in sheltered areas, such as car-ports, garages, utility rooms and similar areas of a residence.
International Standards Organisation (ISO) - Technical Committee : ISO/TC 197 Hydrogen technologies.	ISO 16110-1:2007 Hydrogen generators using fuel processing technologies — Part 1: Safety.	Last reviewed 2016. Status current. ISO 16110-1:2007 applies to packaged, self-contained or factory matched hydrogen generation systems with a capacity of less than 400 m3/h at 0 °C and 101,325 kPa, herein referred to as hydrogen generators, that convert an input fuel to a hydrogen-rich stream of composition and conditions suitable for the type of device using the hydrogen (e.g. a fuel cell power system or a hydrogen compression, storage and delivery system). ISO 16110-1:2007 is applicable to stationary hydrogen generators intended for indoor and outdoor commercial, industrial, light industrial and residential use.
International Standards Organisation (ISO) - Technical Committee : ISO/TC 197 Hydrogen technologies.	Hydrogen detectors.	Scope covers standardization in the field of systems and devices for the production, storage, transport, measurement and use of hydrogen.

International Standards Organisation (ISO) - Technical Committee : ISO/TC 197 Hydrogen technologies.	IEC/TS 62282-1, 2013 Fuel cell technologies – Part 1: Terminology.	Replaces IEC 62282-2 (2005-03) – Fuel cell technologies – Part 1: Terminology. This part of IEC 62282 provides uniform terminology in the forms of diagrams, definitions and equations related to fuel cell technologies in all applications including but not limited to stationary...
International Electrotechnical Commission (IEC)	IEC 62282-2-100:2020 Fuel cell technologies - Part 2-100: Fuel cell modules – Safety.	Replaces IEC 62282-2 (2005-03). IEC 62282-2-100:2020 provides safety related requirements for construction, operation under normal and abnormal conditions and the testing of fuel cell modules.
International Electrotechnical Commission (IEC)	EN IEC 62282-3-100:2020 Fuel cell technologies - Part 3-100: Stationary fuel cell power systems – Safety.	Replaces IEC 62282-3-1 This part of IEC 62282 applies to stationary packaged, self-contained fuel cell power systems or fuel cell power systems comprised of factory matched packages of integrated systems which generate electricity through electrochemical reactions.
International Electrotechnical Commission (IEC)	BS EN 60079-29-1:2016. Explosive atmospheres. Gas detectors. Performance requirements of detectors for flammable gases.	Replaces IEC 61779-1. This part of BS EN 60079 gives the requirements for the construction, testing and performance of portable, transportable and fixed equipment for the detection and measurement of flammable gas or vapour concentrations with air.
International Electrotechnical Commission (IEC)	BS EN 60079-10-1:2015 Explosive atmospheres. Classification of areas. Explosive gas atmospheres.	Replaces Supersedes EN 60079-10. This second edition of BS EN 6007910-1 Explosive atmospheres. Classification of areas. Explosive gas atmospheres sets out the essential criteria against which ignition hazards can be assessed and gives guidance on the design and control parameters which can be used in order to reduce such hazards.
The U.S. Department of Energy (DOE).	Regulator's Guide to Permitting Hydrogen Technologies, 2004.	The U.S. Department of Energy (DOE), in conjunction with the National Labs and National Code bodies, has developed the first modules in a family of documents to aid in the permitting of hydrogen energy systems. The Overview and first two modules of the Regulator's Guides to Permitting Hydrogen Technologies have been published and are available for all interested parties online. http://www.hydrogenandfuelcellsafety.info/regulator-guide
The US National Fire Protection Association.	NFPA 55 – Storage, Use and Handling of Compressed Gases and Cryogenic Fluids in Portable and Stationary Containers, Cylinders and Tanks, 2020	This code shall apply to the installation, storage, use, and handling of compressed gases and cryogenic fluids in portable and stationary cylinders, containers, equipment, and tanks in all occupancies.

The US National Fire Protection Association.	NFPA 2 - Hydrogen Technologies Code, 2020	This code provides fundamental safeguards for the generation, installation, storage, piping, use, and handling of hydrogen in compressed gas (GH2) form or cryogenic liquid (LH2) form.
The US National Fire Protection Association.	NFPA 853 - Standard for the Installation of Stationary Fuel Cell Power Systems, 2020	This standard provides fire prevention and fire protection requirements for safeguarding life and physical property associated with buildings or facilities that employ stationary fuel cell systems of all sizes.
Health and Safety Executive (HSE)	Installation permitting guidance for hydrogen and fuel cell stationary applications: UK version, 2009	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.
BSI Standard	BS EN 60079-29-2:2015 Explosive atmospheres. Gas detectors. Selection, installation, use and maintenance of detectors for flammable gases and oxygen.	Replaces B S EN 50073 –This part of IEC 60079-29 gives guidance on, and recommended practice for, the selection, installation, safe use and maintenance of electrically operated Group II equipment intended for use in industrial and commercial safety applications and Group I equipment in underground coal mines for the detection and measurement of flammable gases complying with the requirements of IEC 60079-29-1 or IEC 60079-29-4.
European Industrial Gases Association (EIGA)	IGC Doc 75/07/E, 2007 Determination of safe distances.	Replaces IGC 75/01/E/rev - Determination of safety distances. The primary objective of this document is to define a philosophy to determine suitable separation distances for all equipment, pipework and storage to allow member companies to develop consistent standards across the industry.
European Industrial Gases Association (EIGA)	IGC Doc. 15/06 Gaseous hydrogen stations.	Replaces IGC Doc 15/96 –Gaseous Hydrogen Stations. This Code of Practice has been prepared for the guidance / best practices of designers and operators of gaseous hydrogen stations. Its application will achieve the primary objective of improving the safety of gaseous hydrogen station operation.
European Industrial Gases Association (EIGA)	Doc. 23.07/18 Hydrogen	Safety training leaflets summarise the basic operational safety knowledge which needs be known by employees working in the gas industry. Each leaflet addresses a specific topic as identified in the title. EIGA Doc 23 Safety Training of Employees provides information on the various combinations

		of leaflets which define the scope of safety training for a variety of specific jobs.
European Industrial Gases Association (EIGA)	Doc. 230/20Safe Catalyst Handling in HyCO Plants	HYCO plants utilise a number of catalyst types and catalytic technologies to produce hydrogen, carbon monoxide, or mixtures thereof. These catalysts are comprised of various chemical compounds across a number of support materials and structures, and reaction occurs in tubular, fixed bed, or modular reactors. Most of these catalysts are replaced periodically. There are safety hazards involved in the storage, loading, unloading, and disposal of these catalysts. These hazards include the handling of self-heating or potentially pyrophoric materials and the presence of toxic metals (for example, nickel, chromium, etc.), toxic metal carbonyls, and hexavalent chromium. There are also hazards associated with verification of uniformity of catalyst installation, including managing the differential pressure measurements taken during loading of reformer tubes.
European Industrial Gases Association (EIGA)	Doc. 220/19Environmental Guidelines for Permitting Hydrogen Plants Producing Less Than 2 Tonnes Per Day.	Small hydrogen plants used in, for example, fuelling applications have a low environmental impact due to size and technology employed. Over regulation of these plants is a barrier to the development of hydrogen as an energy carrier. On-site hydrogen production is also expected to be required in relation to road vehicle refuelling. This publication is on the environmental impacts and operational controls for these packaged hydrogen plants and is intended to be used as guidance for permitting these plants so that simpler permitting can be applied.
European Industrial Gases Association (EIGA)	Doc. 215/18HYCO Plant Gas Leak Detection and Response Practices	HYCO plants are facilities that produce hydrogen, carbon monoxide and mixtures of these gases. These plants are typically operated with feed stocks such as natural gas, refinery off gas, naphtha, and other light hydrocarbons. Gases from HYCO plants are flammable and can be toxic; therefore, appropriate leak prevention design, monitoring, and response practices shall be applied to ensure personnel and public safety. Leak detection is part of an overall system comprising design aspects, leak detection devices, operating practices and the response to leak indications. This publication applies to HYCO plants. Information in this publication may also be applied to facilities, such as trailer fill stations, cylinder fill stations, electrolytic production facilities, or vehicle fuelling stations.
European Industrial Gases	Doc. 210/17Hydrogen Pressure Swing Adsorber (PSA) Mechanical Integrity Requirements.	Industrial gas companies operate and maintain hydrogen production facilities. Pressure swing adsorption (PSA) exists as the primary method of product purification in most large-scale hydrogen

Association (EIGA)		production facilities. The maintenance and inspection of PSA equipment is critical to the overall reliability and safe operation of the facility. Mechanical integrity of the vessels, piping, and piping components is crucial to ensure that this equipment is fit for service. This publication is an industry-wide guideline for in-service mechanical integrity of PSA units and is intended to contribute to the operational safety and reliability of these units. This publication is not intended to address the details of design and installation of PSA vessels and piping. This publication applies to PSA units with reformer syngas, refinery off-gas, and other hydrogen containing off-gases. This publication is focused on the parts of the PSA that are subjected to pressure cycles, although some consideration is given to the noncyclic portions of the PSA system.
European Industrial Gases Association (EIGA)	Doc. 155/21Best Available Techniques for Hydrogen Production by Steam Methane Reforming.	This EIGA publication provides guidance on some best available techniques for the (co-)production of hydrogen, carbon monoxide and their mixtures by steam methane reforming. Focus, environmental management. It is intended to support and complement the EU Best Available Technique (BAT) reference documents (BREF) (REF [REFineries], LVOC [Large Volume Organic Chemicals], LVIC [Large Volume Inorganic Chemicals], WGC [Waste Gas Chemicals]) by the European Integrated Pollution Prevention and Control Bureau (EIPPCB). This publication has been updated and also incorporates EIGA Doc 183, Best Available Techniques for the Production of Hydrogen, the Co-Production of Hydrogen, Carbon Monoxide and their Mixtures by Steam Methane Reforming [1].1 (withdrawn).
Compressed Gas Association (CGA)	CGA G-5.5-2014, Hydrogen Vent Systems	Current version, 2014. This publication presents design guidelines for hydrogen vent systems used in gaseous and liquid hydrogen systems at user sites and provides recommendations for safe operation of these vents. Additional information on hydrogen can be found in CGA G-5,Hydrogen, CGA G-5.4, Standard for Hydrogen Piping Systems at User Locations, CGA Handbook of Compressed Gases, and NFPA 55, Compressed Gases and Cryogenic Fluids Code [1, 2, 3, 4].1Pressure relief devices (PRDs) for cylinders and tube trailers required by U.S.
Compressed Gas Association (CGA)	CGA/GAS - CGA C-10, Guideline to prepare cylinders and tubes for gas service and changes in gas service.	This document provides a guide to those establishing procedures for changing cylinders from one gas service to another.

American Institute of Aeronautics & Astronautics	ANSI/AIAA G-095A:2017. Guide to Safety of Hydrogen and Hydrogen Systems.	Replaces, NASA NSS 1740.16. This Guide presents information that designers, builders, and users of hydrogen systems can use to ensure safe hydrogen systems or resolve hydrogen hazards. Guidance is provided on general safety systems and controls, usage, personnel training, hazard management, design, facilities, detection, storage, transportation, and emergency procedures. Pertinent research is summarized, and supporting data are presented relative to the topic. Additional information regarding codes, standards, and regulations, as well as a sample safety data sheet, extensive bibliography, and other useful material can be found in the annexes.

Appendix I Assumptions underpinning the cost estimate for each repurposing scenario

Scenarios 1 and 2a

1. Scenario 1 - The concept is that electricity is taken from offshore wind farms. A bulk carrier is converted for the process of electrolysis to generate hydrogen offshore and then the hydrogen is piped to shore in an existing pipeline which has been identified as a candidate through extensive study.
2. Scenario 2a - The concept is that electricity is taken from offshore wind farms. Existing offshore platforms are converted to electrolysis platforms to generate hydrogen offshore and then the hydrogen is piped to shore in an existing pipeline which has been identified as a candidate through extensive study.
3. For Scenarios 1 and 2a an assumption of 60 MW of electrolyser capacity has been used with associated produced hydrogen of approximately 21,000 kg H_2 per day. This is in line with potential layout options shown in reference [6].
4. It should be noted that the technical feasibility of this option will, amongst other matters, require sufficient space and weight on an offshore platform. Providing such space and weight may render the option uneconomic.
5. It is assumed that a Proton Exchange Membrane (PEM) Technology is used and cost is assumed to be 400 £/kW. This is in the range of a number of referenced benchmarks and is considered suitable for this level of study.
6. Demineralised water is provided to the electrolysis unit by a desalination unit.
7. The total topsides CAPEX for the facilities on the platform is assumed to be 5 times the equipment cost of the electrolysis, desalination and hydrogen compressor. This is to allow for auxiliary equipment as well as piping, metering, instrumentation and control, electrical connections, structural modifications, engineering and installation etc.
8. Note that if a new compressor is required this could add significant weight and space requirements which could mean a new bridge linked platform which has not been included in the cost.
9. The model has the option to include the cost of a new hydrogen pipeline to shore if required. In the scenarios included in the report this option is turned ‘off’ for Scenario 2b due to the studies focus on reuse of existing infrastructure.
10. In scenario 1 the use of a converted bulk carrier means that the requirement for a new pipeline is turned ‘on’ in our inhouse cost model. Cost included for an 18in 100km new pipeline £40MM. (Determined through in-house cost model). Again, caveated that this is a Class 4 estimate.
11. If hydrogen is to be transported to shore in a pipeline mixed with natural gas then a PSA (Pressure Swing Absorption) plant will be required at the shore to separate the hydrogen and natural gas. This option is turned ‘on’ for scenario 2a included in this report.
12. The hydrogen storage is not considered in the cost build-up. If to be included then on shore in salt caverns would be the most viable option. Indicative costs would be in the region of £380MM including contingency at 30%. This cost is for 1 onshore salt cavern, 300,000m3 in size. This option can be turned ‘on’ for scenarios if required.
13. 15% G&A (General and Administrative) is added for Owners Costs. This could include a project management team, surveys, insurance and certification etc.
14. 30% contingency is added to allow for the lack of granularity of the design at this early stage. In line with Class 4 estimate.

15. Pre-FID (Final Investment Decision) cost is assumed to be 5% of CAPEX. This could include conceptual and FEED studies and the teams to supervise these studies.
16. OPEX and ABEX (abandonment expenditure) are based on percentages of CAPEX. The percentages have been derived from Que$tor software and have been previously used for scoping/ feasibility studies within the Vysus Group. The percentages are consistent with other referenced resources [7]. These are deemed to be suitable for a Class 4 estimate.
17. The cost of electricity has been included assuming system 95% uptime. Pricing outlined in subsequent sections.

Scenario 2b and 4b

18. The concept is that natural gas is converted into hydrogen in the steam methane reforming process and carbon dioxide is generated as a by-product. The resulting hydrogen can be stored in onshore salt caverns (England, Northern Ireland and North Wales); Hydrogen Storage Plays in the Midland Valley of Scotland (Carboniferous age sedimentary deposits of the D'Arcy-Cousland Anticline and the Balgonie Anticline close to Edinburgh) and other forms of storage) and the carbon dioxide can be injected offshore for sequestration.
19. The unit in Scenario 2b generates 11,880 kg hydrogen per day. Benchmarked as a potential scenario in ref [6].
20. Scenario 4b hydrogen production is 1,000 kg hydrogen per day, retrofit for the purpose of reducing flare gas. Single unit assumed – approximate 40ft of footprint, reasonable for a producing asset.
21. The total facilities CAPEX is assumed to be 5 times the equipment cost of the SMR Unit (£5MM) hydrogen and CO_2 compressor. This is to allow for auxiliary equipment as well as piping, metering, instrumentation and control, electrical connections, civils, engineering and installation etc.
22. If hydrogen is to be transported to shore in a pipeline mixed with natural gas then a PSA (Pressure Swing Absorption) plant will be required at the shore to separate the hydrogen and natural gas. This option is turned 'on' for scenario 2b and 4b included in this report.
23. The hydrogen storage is not considered in the cost build-up. If to be included then on shore in salt caverns would be the most viable option. Indicative costs would be in the region of £380MM including contingency at 30%. This cost is for 1 onshore salt cavern, 300,000m3 in size. This option can be turned 'on' for scenarios if required.
24. 15% G&A (General and Administrative) is added for Owners Costs. This could include a project management team, surveys, insurance and certification etc.
25. 30% contingency is added to allow for the lack of granularity of the design at this early stage.
26. Pre-FID (Final Investment Decision) cost is assumed to be 5% of CAPEX. This could include conceptual and FEED studies and the teams to supervise these studies.
27. OPEX and ABEX (abandonment expenditure) are based on percentages of CAPEX. The percentages have been derived from Que$tor software and have been previously used for scoping/ feasibility studies within the Vysus Group. The percentages are consistent with other referenced resources [7]. These are deemed to be suitable for a Class 4 estimate.
28. Natural gas price is assumed to be 38p/ therm.

Appendix J Description of cost model configuration and cost block switches.

The cost model allows for cost blocks to be switched on or off depending on individual candidate options within the scenarios. An example of the flexibility in the model would be a change in the base case from the repurposing of an existing pipeline to shore, to a requirement for a new pipeline. The base case for each scenario 'on/off' cost blocks are indicated below.

- 'Green' indicates 'on' where costs have been included in the cost comparison.
- 'Red' indicates 'off', where costs are not included in the cost comparison.

Figure 81. Base Case Cost Blocks 'On/Off'

Cost Type	Cost Block	Scenario 1	Scenario 2a	Scenario 2b	Scenario 4b	Scenario 4c
CAPEX (£/ kg H_2)	Offshore Wind					
	Electrolysis					
	Desalination Plant					
	Compression					
	Topside Modifications					
	SMR Equipment					
	Gas to Graphene Equipment					
	Repurposing of existing pipeline to shore					
	New Pipeline to shore					
	Onshore Storage					
	CO_2 Injection					
	G&A	15% TOTAL CAPEX	15% TOTAL CAPEX	15% TOTAL CAPEX	15% TOTAL CAPEX	
	Contingency	30% TOTAL CAPEX	30% TOTAL CAPEX	30% TOTAL CAPEX	30% TOTAL CAPEX	
OPEX (£/ kg H_2)	OPEX	2% -5% of CAPEX blocks	2% -5% of CAPEX blocks	2% -5% of CAPEX blocks	2% -5% of CAPEX blocks	
ABEX (£/ kg H_2)	ABEX (DECOMM)	10% -20% of CAPEX blocks	10% -20% of CAPEX blocks	10% -20% of CAPEX blocks	10% -20% of CAPEX blocks	
Electricity (£/ kg H_2)	Electricity					
Gas (£/ kg H_2)	Gas					

Appendix K Project risks and opportunities, detailed findings

Figure 82.Hazard identified during literature review.

Hazard / threat	Risk ranking / maturity level	Mitigation / control
2. Economics		
H_2 export via disused natural gas pipeline. • The condition of redundant pipelines is often uncertain and would require assessment and potentially remedial intervention before re-use. The costs associated with the reuse of pipelines are principally associated with implementing any remedial action (such as installing additional concrete mattresses) resulting from analysis of the surveys to confirm suitability.	Challenge – novel concept / scenario.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
7. Safety (Prevention of major accidents and incidents)		
Hydrogen release (flammable). • Hydrogen has a wide range of flammability (4 – 77 vol% in the air, ambient pressure and temperature) but a lower ignition energy compared to common hydrocarbon fuels; Leak - molecule small size leaks easily, creates flammable clouds. • A hydrogen flame will be more likely to accelerate and transition to a detonation, potentially resulting in more severe consequence (e.g. structural failure and/or fatalities.) • A hydrogen flame may be more dangerous since it is nearly invisible and emits little infrared heat which makes it difficult to be detected. • H_2 leakage rates from pipework, fittings and equipment may be higher than those of natural gas, but because H_2 has a much lower density than natural gas, an H_2 leak dispersion profile would differ from natural gas. This means that the risks associated with replacing natural gas with H_2 cannot be assessed by a direct comparison of properties; instead, a detailed understanding of the nature and magnitude of H_2 leaks and the behavior of H_2 must be used to assess whether and how H_2 accumulations might occur and the severity of any resulting explosion or fire. • Inhalation - can cause asphyxia in high concentrations. • Incompatible materials - can form explosive mixture with air. May react violently with oxidizing agents.	Challenge – transfer potential.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Oxygen release - resulting in an oxygen rich environment. • Oxygen enrichment of the atmosphere, even by a few percent, considerably increases the risk of fire. • Sparks which would normally be regarded as harmless can cause fires. Materials which do not burn in air, including fireproofing materials, may burn vigorously or even spontaneously in oxygen-enriched air. • Increase of flammability of all materials resulting in fires (also in normally unexpected locations), resulting in structural failure and/or fatalities.	Challenge – transfer potential.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.

Gas permeability across the membrane in electrolysis system. • Formation of a flammable hydrogen-oxygen atmosphere in electrolysis cell - potential for fire and explosion. • Potential for catalytic recombination of hydrogen and oxygen stored inside the PEM cells. This process is spontaneous and exothermic which can lead to the total destruction of the electrolyser.	Challenge – transfer potential.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Syngas release (Hydrogen component is flammable). • Syngas fire hazard zones get bigger with changes in the H_2/CO ratio gas mixture containing larger proportion of H_2. • Inhalation - can cause asphyxia in high concentrations. • Incompatible materials - can form explosive mixture with air. May react violently with oxidizing agents.	Challenge – transfer potential.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Syngas release (Carbon Monoxide component is toxic) • The effect of a release of syngas without ignition is the toxic hazard related to the toxicity of carbon monoxide contained in the mixture. • Inhalation - can cause asphyxia in high concentrations.	Challenge – transfer potential.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Carbon Dioxide release (toxic) • Hazard of asphyxiation (CO_2 displace oxygen in air). • Inhalation of elevated concentration of CO_2 can increase the acidity of the blood, triggering adverse effects on the respiratory, cardiovascular and central nervous system.	Challenge – transfer potential.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Acetylene gas release (Flammable / Reactive) • Under certain conditions, even in the absence of any air or oxygen, it can decompose explosively into its constituent elements, carbon and hydrogen.	Challenge – transfer potential.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Associated hazards and risks of graphene powder / flakes. • Limited research has been published on the toxicology of graphene. Further materials characterization and mechanistic toxicity studies are essential for safer	Challenge – novel concept / scenario.	Industry representation / Government policy, regulatory

design and manufacturing of graphene materials in order to optimize biological applications with minimal risks for environmental health and safety.		framework guidance.
Dropped Objects. • Lifting requirements for the operation and maintenance of the Hydrogen generation plant; existing crane capability may limit options of layout and location of equipment.	Established practice	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance
Hazardous areas classification and ignition control. • Hazardous area classification would require to be redefined to account for Hydrogen and Oxygen risk. This will in turn has an impact on the EX rating of the equipment installed within the hazardous zones.	Challenge – transfer potential.	Industry representation / Government policy, regulatory framework guidance.
Electrical installation (high voltage from field). • Implications of high voltage systems/equipment with respect to interaction on humans, explosions and Electromagnetic interferences and footprint on the installation.	Established practice	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Boosting produced H_2 to export pressure. • Engines and turbines can be sensitive to hydrogen additions. Gas engines can run into engine knocking difficulties at small hydrogen concentrations and adapting to the fluctuations of the hydrogen level can be a challenge. For gas turbines, power output, emissions and flame stability can be an issue. • Particular attention must be given to material compatibility and fugitive losses through the seals	Challenge – transfer potential.	Operator risk management model. / Independent verification.
Emergency Procedures. • Emergency procedures may need to change where H2 is present to take account of differences in transport, combustion and ignition properties and the behavior of H_2 as a gas.	Challenge – transfer potential.	Industry representation / Government policy, regulatory framework guidance.
H_2 export by existing natural gas pipeline. • Hydrogen and natural gas have different physical and chemical properties, such as inter alia density, calorific value, and burning velocity. As such, the admixture of hydrogen impacts the integrity of the network and the functioning of end-use appliances connected to the network.	Challenge – novel concept / scenario.	Industry representation / Government policy, regulatory framework guidance.
Change in plasticity of the steel grades • Current condition of the integrity of the pipelines and influence that the hydrogen gas has on the fatigue properties of existing pipelines.	Challenge – novel concept / scenario.	Industry representation / Government policy,

		regulatory framework guidance.
H_2 export via disused natural gas pipeline. • The main risk associated with reusing a pipeline is in not identifying areas of high corrosion and/or particularly thin walls and overestimating the integrity of the pipeline for its new duty of transporting.	Challenge – novel concept / scenario.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Material corrosion. • H_2, O_2 and Demineralised water are corrosive leading to System leaks, composition change, contamination of product.	Challenge – transfer potential	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Embrittlement • Hydrogen is known to cause embrittlement - degradation of mechanical properties of metals, can lead to component failure. • The hydrogen component of Syngas is known to cause embrittlement - degradation of mechanical properties of metals, can lead to component failure. • In CCS operations associated with SMR scenarios it is likely that CO_2 will be handled close to, or above, its critical pressure. Significant hazards associated with the low temperature associated with supercritical CO_2 can result in brittle fracture of surrounding equipment.	Challenge – novel concept / scenario.	Industry representation / Government policy, regulatory framework guidance.
9. Availability and reliability		
Operations and maintenance. • The lower density and lower calorific value of H_2 compared to natural gas means that gas velocities in pipelines and gas installations will be up to three times higher.	Challenge – novel concept / scenario.	Industry representation / Government policy, regulatory framework guidance.
Renewable source of power, nearby OWF. • Reliability of constant power supply from OWF • Require back up power (e.g. Auxiliary power, or cabled power supply from shore).	Challenge – novel concept / scenario.	Industry representation / Government policy, regulatory framework guidance.
Synergies with oil & gas decommissioning and life extension		
• If a pipeline was transferred from one party to another, the acquiring party would have to accept the decommissioning obligations once no reuse potential exists (in the case that the hydrogen production / transportation ceases.	Challenge – novel concept / scenario.	Industry representation / Government policy, regulatory

		framework guidance.

Figure 83. Issues identified during the consultation process.

Responses to consultation questionnaire.	Risk ranking / maturity level	Mitigation / control
1. Scope		
Within the context of existing offshore installations, wells, pipelines, plant, and equipment, what should be considered as being economically and technically viable for repurpose, recycle or re-use for the production of hydrogen?		
Scope of infrastructure and equipment to be considered Wells, pipelines and offshore structures in key locations. Plant/Equipment for O&M (personnel or robotic). Potential uses • Pipelines for hydrogen transportation to existing natural gas distribution infrastructure • Platform structures for hosting equipment and • Well infrastructure if possible for hydrogen storage. • Potential re-use of compression for hydrogen injection. • There is also potential for onshore hydrogen generation and transfer to offshore for storage.	Opportunity	
Fitness for purpose Fitness for purpose should be assessed on a case-by-case basis recognising every installation is different. Every opportunity should be considered ensuring it is safe to do so. Generally, pipelines, plant and equipment may be easier to repurpose than wells and entire offshore installations. Re-use and repurposing assessments should be made in good time, and if there are no opportunities, the decommissioning project should progress to ensure cost effective decommissioning. Inspections should be carried out in all areas following existing regulations to ensure the integrity of the equipment, etc.	Challenge – transfer potential.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance
Wells and topsides equipment For wells, and topside equipment it would require an appraisal per well/installation. At each installation the level of NORM will vary, the suitability for repurposing will be site specific based on clean-up costs. Wells are currently up-dip or at the top of the structures, it may be more cost effective to sequestrate further down dip in a saline aquifer providing much larger storage capacity.	Challenge – transfer potential.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance
Rotating equipment – Reciprocating compressors • Rotating machinery equipment is bespoke and designed to operate with specific mol weights, flows and pressures. • For CO_2 injection it is possible to repurpose compressors to operate within strictly defined operating conditions • For hydrogen, the low molecular weight makes it necessary to redesign rotating machinery to suit operating requirements.	Challenge – transfer potential.	Operator risk management model. / Independent verification.

Conflicts Potential conflicts for re-use of infrastructure and the associated subsurface geological units that may be accessed by the infrastructure, should be part of the assessment when considering change of use for offshore installations and subsurface assets. In the context of the energy transition, conflicts could arise from proposals for re-use infrastructure, above and below seabed for: CO_2 transport and storage; hydrogen generation and transport; other potentially unrelated uses, e.g. siting of offshore wind instillations. Criteria for prioritisation of infrastructure re-use for CO_2 transport, rather than for hydrogen, should include: proximity to extent of subsurface formations identified as likely for CO_2 storage; pipeline and well infrastructure that is acid-gas resistant and so most suitable for CO_2 transport.	Challenge – novel concept / scenario.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
2. Economics		
When considering CAPEX, OPEX, ABEX and Revenue generation associated with the reuse, recycle and repurposing of infrastructure and equipment for offshore hydrogen production, what do you regard as the priority issues / problem areas?		
Alternative to decommissioning • ABEX, OPEX revenue generation to cover ongoing costs. • OPEX on HSE risk • Must be a viable alternative to decommissioning/abandonment.	Challenge – novel concept / scenario.	Operator risk management model / Government policy, regulatory framework guidance.
Who pays? If infrastructure is being considered to be repurposed for hydrogen, it is important to understand who is responsible for associated studies, project development, and interim maintenance costs in the gap between oil/gas production and repurposed use. Again, these will likely be on a project-by-project basis but is certainly key priority issue.	Challenge – novel concept / scenario.	Government policy, regulatory framework and guidance.
Transfer of Liability. A mechanism should be agreed to transfer liability to the new user. This is a key policy area to address.	Challenge – novel concept / scenario.	Government policy, regulatory framework and guidance.
Business Models. Similar to CCUS, the business environment should be set up for success. BEIS will have some learnings on this from the work they have been progressing on business models for CCUS. What gets decommissioned & what gets reused – It's likely that only part of the asset will be re-used or repurposed. For example, an installation may have six pipelines, when only one will be repurposed. When looking to transfer liability, do we transfer only those component parts to be repurposed or, the whole asset? – this process could have the potential to become overly complicated.	Challenge – novel concept / scenario.	Government policy, regulatory framework and guidance.
Suitability of existing equipment. The suitability of existing equipment for high hydrogen content with regard to stress cracking etc. High OPEX to maintain facilities offshore. High capital and operating cost for carbon capture and storage equipment if offshore gas reforming to hydrogen and carbon dioxide products is considered. This would	Challenge – novel concept / scenario.	Operator risk management model. / Independent verification / Government policy,

probably be best performed onshore from a gathering system and CO2 transported back offshore to the storage site.		regulatory framework guidance
Switch over of jackets. The switch over of jackets to hydrogen production will require significant CAPEX with the disposal of contaminated units being required.	Challenge – novel concept / scenario.	Operator business model / Government policy, regulatory framework guidance.
Commodity pricing Future hydrogen pricing Electricity cost (if green H_2)		Government policy, regulatory framework guidance.
Operating cost to maintain offshore facilities.		Operator business model.
Rotating equipment – Reciprocating compressors For rotating machinery using low mol weights it is necessary to consider the sealing systems which will be different to those used on higher mol weight gases such as natural gas at 18, or CO_2 at ~40. Pipeline cost are in the region of ~ €1mio per km. Gas turbines can be re-used with minimal work if the H_2 content is <70%. For compression the only compressors that can be used are reciprocating types. Even on these there is a minimum flow required in the region of 150kg/hr with pressures of 100 bar.	Challenge – transfer potential	Engineering solution.
3. Technical feasibility		
When considering the technical feasibility of a project to produce hydrogen from a repurposed offshore asset, what do you regard as a priority / problem area?		
Economics Understanding the economics.	Challenge – novel concept / scenario.	Operator business model / Government policy, regulatory framework guidance.
Pipeline availability Viability of pipeline use.	Challenge – novel concept / scenario.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance
Storage capacity Storage of hydrogen and CO_2.	Challenge – novel concept / scenario.	Operator risk management model. /

		Independent verification.
Use of raw seawater Corrosion problems**.**	Challenge – transfer potential	Operator risk management model. / Independent verification.
Remaining life span Remaining life span of the structure from sea-bed to surface. Smaller southern North Sea jackets have relatively easily removed topsides, but condition and remaining life-span of the legs is required to exceed the future planned life-span of the hydrogen production.	Challenge – novel concept / scenario.	Operator risk management model. / Independent verification.
Integrity of structure and components The integrity of the component parts is important. Many of the assets are old, have already exceeded their design life and therefore integrity should be a key consideration for any element to be repurposed. The maintenance costs, and any integrity assessments / pressure checks are a key consideration, including who is responsible for conducting these (original owner or new owner) and how long for ?	Challenge – novel concept / scenario.	Operator risk management model. / Independent verification.
Compatibility with existing infrastructure Hydrogen compatibility with existing pressure containing infrastructure. Rotating equipment – Reciprocating compressors Parameters to consider particularly if producing hydrogen offshore and pumping to onshore include: • Flowrates; • Pressures; • Gas composition (is it 100% H_2 or a mixture of gases); • Space; • Available power.	Challenge – novel concept / scenario.	Operator risk management model. / Independent verification.
Efficiency and size of electrolysers.	Challenge – novel concept / scenario.	Technological innovation.
Possibility to produce blue H_2 offshore so as to re-inject CO_2 in situ.	Challenge – novel concept / scenario.	Industry representation / Government policy, regulatory framework guidance.
Relationship to decommissioning plans Priority to enable clarity of what is in scope as well as out. There is a desire to ensure repurposing Is not used as a delaying tactic to further defer decommissioning.	Challenge – novel concept / scenario.	Operator risk management model / Government policy, regulatory framework guidance.
4. Proximity and connectivity		
When considering the location of an offshore hydrogen production repurposing project what are the issues you consider as important to your organisation?		

Existing oil and gas infrastructure (hardware) Proximity to pipeline for export of product, by product (CO_2) and import of feedstock (CH_4). Proximity to suitable hydrogen storage options (including, subsurface). Close proximity to an integrated gas production, gas reforming, carbon capture, carbon distribution and storage infrastructure.	Challenge – transfer potential	Proximity.
Proximity to wind farms Existing pipeline routing & proximity to planned/potential wind farms. The better the connectivity between the 2 components of the offshore hydrogen production the better.	Challenge – transfer potential	Proximity.
CO_2 Storage in depleted hydrocarbon reservoirs Understanding of CO_2 behaviour in informing site selection and injection strategy, includes considerations of: - capacity (is the reservoir an appropriate size for the project) - integrity (can the CO_2 be safely stored at this location) and - injectivity (can the CO_2 be injected at a rate which fits with the need) - Geological behaviour of CO_2 in situ at injection sites Storage sites will need to be monitored to ensure permanent storage - proximal to suitable facility/ pipelines for CCS - CO_2 injection wells that may not meet the current integrity standards for the new service would need recompletion. - Well packers may not to be compatible with CO_2 and would need to be replaced.	Challenge – novel concept / scenario	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Geological storage of CO_2 and protection from inadvertent sterilisation Permanent geological storage to reduce CO_2 emissions at large scale captured from sources in the UK are an essential component of the nation's plans to achieve net-zero emissions by 2050. The UK has an enviable natural geological CO_2 storage resource, comparable to that of Norway, that is considered the basis for a nascent transport and storage industry for CO_2 captured in the UK and beyond. This natural resource, which comprises depleted fields and geological formations, should not be sterilised by infrastructure re-use without due consideration of the role of CO_2 storage for emissions reduction for the UK. We recognise that some UK storage resources are very extensive and not all will need to be protected from inadvertent sterilisation. Identification of CO_2 storage resources that are prioritised for protection should be part of a balanced appraisal for the implementation of low-carbon technologies, including offshore hydrogen production and offshore hydrogen subsurface storage, to achieve net-zero emissions.	Challenge – novel concept / scenario.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Water depth and bathymetry Offshore hydrogen production associated with renewable wind will need consideration of water depth and bathymetry in relation to the existing infrastructure. If hydrogen is to be stored in the offshore environment, then additional consideration of suitable geological storage units is also an important factor, e.g., depth, capacity and lithology of storage units.	Challenge – novel concept / scenario.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Existing oil and gas infrastructure (workforce) These assets are strategically located for the oil and gas industry, which has created both centralised high skilled jobs in certain areas of the UK, but also, local community hubs. Both should be strategically leveraged by the hydrogen industry as we	Opportunity	Industry representation / Government policy, regulatory

collectively progress towards a lower carbon future. There is as much value in transitioning (re-purposing) a workforce as there is a piece of infrastructure.		framework guidance.
Rotating equipment - Compressors Proximity and connectivity considerations will be dependent on the destination of export gases and import of feed stock gases. Considerations will include: • Flowrates; • Pressures; • Gas composition (is it 100% H_2 or a mixture of gases); • Space; • Available power.	Challenge – novel concept / scenario.	Operator risk management model.
5. Policy, regulation, codes and standards		
When considering government policy, regulation, codes and standards, what issues do you consider as being key to the stimulation of a safe and sustainable market for repurposing of infrastructure and equipment?		
Clarity and consistency of regime Clarity and consistency of the regulatory regime;	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance.
Early clarity on codes and standards	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance.
Liabilities Understanding liabilities particularly in the long-term.	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance.
Cross sectoral coordination Co-ordination and agreement across sectors, i.e. oil & gas and renewables.	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance.

Policy, regulation, codes and standards A pragmatic approach would be requested. Those with an understanding of offshore infrastructure should be responsible for any new policy, regulation, codes and standards. Views should be taken from industry on what current regulations for offshore work well (or not) and these views used for any new policy, etc.	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance.
Carbon pricing For hydrogen to move from trial to reality, it requires integrated green & blue hydrogen & CCS, which is only likely to be viable with reliable carbon pricing.	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance.
Investment economics and regulatory regime The development economics obviously have to work. Investors must have a high degree of confidence in the investment proposals. Incentives (carrot or stick) for carbon sequestration would be expected to be necessary to drive investment into these areas.	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance.
Relationship to decommissioning plans Sector is concerned less about the economic or technical issue which we believe the market can evaluate and more about the legal and regulatory framework to enable discussion and assessment.	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance.
Rotating equipment – Reciprocating compressors Machinery should comply to the relevant API specifications.	Established practice.	Operator risk management model.
6. Quality		
When considering quality management and assurance associated with the repurpose of offshore infrastructure for the production of offshore hydrogen, what issues do you regard as being a priority?		
Benchmark quality of assets Understanding the real situation with regard the assets. Are they suitable for re-purposing?	Challenge – transparency.	Independent verification / Government policy, regulatory framework guidance.
Ageing infrastructure Aged infrastructure approaching cessation of production (CoP) will have had maintenance budgets managed carefully with regard to the expected economic life. There would be a question on the future lifespan of the fabric given historical fabric maintenance patterns.	Challenge – transparency.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.

Pipeline integrity In an integrated CO_2 & H_2 offshore storage/sequestration scenario, pipelines need to be suitable for taking dry CO_2, and quality issues on moisture in the CO_2 lines will be a major issue.	Challenge – novel concept / scenario.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Quality assurance - offshore There are very robust system in place for managing quality offshore, this should be followed and transposed for the production of offshore hydrogen.	Opportunity	Industry representation / Government policy, regulatory framework guidance.
7. Safety		
When considering safety management and assurance associated with the repurpose of offshore infrastructure for the production of offshore hydrogen, what issues do you regard as being a priority?		
Clear guidelines on safety standards; leak detection; safety case,	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance.
Understanding the risks involved Requirement to ensure there is a full understanding of the actual risks to people and the environment. That is, full life-cycle risks. What is the impact of hydrogen rich equipment on zoning, gas detection, fire detection, fire protection systems etc?	Challenge – transfer potential	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Hazard identification and assessment Current HAZOP's are based on methane explosions. Re-running for H2 and the different dispersal pattern will be required.	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance
Platform design for safety Platform design may require modification to a more open design.	Challenge – transfer potential	Operator risk management model. / Independent verification / Government policy, regulatory

		framework guidance.
Hydrogen compatibility Hydrogen compatibility with pressure containing equipment. Requirement to minimise manning where possible.	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance
Safety systems - offshore There are very robust safety system in place for managing safety offshore, this should be followed and transposed for the production of offshore hydrogen.	Opportunity	Industry representation / Government policy, regulatory framework guidance
Rotating equipment – Reciprocating compressors Equipment manufacturers shall conform to the required H&S policies offshore.	Challenge – transfer potential.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
The lower mol weight of hydrogen requires new safety mechanisms to be established for offshore H_2 production and handling.	Challenge – novel concept / scenario.	Industry representation / Government policy, regulatory framework guidance
8. Environmental		
When considering environmental management and assurance associated with the repurpose of offshore infrastructure for the production of offshore hydrogen, what issues do you regard as being a priority?		
Understanding the risks involved Ensuring there is a full understanding of the actual risks to people and the environment. Full life-cycle risks.	Challenge – transfer potential.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Overall emission and environmental impact associated with hydrogen generation.	Challenge – transfer potential.	Operator risk management model. / Independent verification /

		Government policy, regulatory framework guidance.
Environmental management - offshore Need to understand the environmental management requirements for hydrogen storage wells and reservoirs, environmental management requirements for CO_2 storage wells and reservoirs. Need to understand monitoring requirements. Expectation that existing procedures should apply (current EIA regulations).	Challenge – transfer potential.	Industry representation / Government policy, regulatory framework guidance
Environmental management on shore Facilities receiving large parts (jackets, topsides, pipelines) and equipment from offshore will need to have suitable permits, plant and personnel in place to handle the mixture of waste materials brought ashore.	Established practice.	Operator risk management model / Government policy, regulatory framework guidance.
Waste management Disposal of contaminated topside equipment. Certifying and assuring CO_2 sequestration is permanent and volume disposed is accounted for.	Established practice.	Operator risk management model / Government policy, regulatory framework guidance.
Water discharge Assuming water desalination will be integrated within the offshore structure, the water discharge will have increased minerals & salt, if close to shore this could have localised effects on marine life.	Challenge – transfer potential.	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Integrity of wells Consideration must be given to the integrity of wells used for the storage of CO_2 from associated carbon capture processes to ensure there is no leakage.	Challenge – novel concept / scenario	Industry representation / Independent verification / Government policy, regulatory framework guidance.
9. Availability and reliability		
When considering the availability and reliability of repurposed infrastructure and equipment for the production of offshore hydrogen, what issues do you regard as being a priority?		

Understanding the risks involved Ensuring there is a full understanding of the actual risks. Full life-cycle risks.	Challenge – transfer potential	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Integrity of equipment Safety must be a priority, as mentioned above, inspections should be carried out in all areas following existing regulations to ensure the integrity of the equipment, etc.	Challenge – transfer potential	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Impact on compression equipment and reliability of compression and metering	Challenge – novel concept / scenario	Technical consideration.
Maintenance Maintenance requirements need to be established. Methods such as hydrogen storage would be an interesting mitigation against market demand fluctuations. H_2 injection / back-production wells likely to have a high availability as will pipeline infrastructure. The extent of processing equipment will likely impact more on availability.	Challenge – transfer potential	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
Rotating equipment – Reciprocating compressors As with most rotating machinery, there is an expectation that availability and reliability shall be in the region of 97% and higher. It is expected that a proper maintenance schedule shall be established and implemented for all assets.	Challenge – transfer potential	Operator risk management model. / Independent verification / Government policy, regulatory framework guidance.
10. Supply chain		
When considering supply chain capacity to service the market for repurposed infrastructure and equipment for the production of offshore hydrogen, what issues do you regard as being a priority?		
Decommissioning capacity Capacity to handle topside repurposing in local shipyards.	Opportunity	Industry representation / Government policy, regulatory framework guidance.

Manufacturing capacity Manufacturing of desalination & electrolyser equipment, currently electrolyser demand is high.	Challenge – novel concept / scenario	Industry representation / Government policy, regulatory framework guidance.
Availability of an established supply chain and transferable skills The supply chain is already well established and ideally placed to service the hydrogen market. Many of the skills within oil and gas are directly comparable to the hydrogen market. Therefore, when establishing the hydrogen market, use the well-established resource and knowledge in place to ensure an integrated energy approach.	Opportunity	Industry representation / Government policy, regulatory framework guidance.
Awareness and familiarity of the traditional offshore supply chain with hydrogen issues and solutions.	Challenge – novel concept / scenario	Industry representation / Government policy, regulatory framework guidance.
Offshore supply chain Appropriate line pipe material of construction for the H_2 or CO_2 service. The offshore supply chain is probably well suited to continuation with a hydrogen industry.	Opportunity	Industry representation / Government policy, regulatory framework guidance.
Rotating equipment – Reciprocating compressors Proven capability from the H_2 production process is key – for rotating machinery the approval of OEMs via a proven record is paramount.	Challenge – transfer potential	Availability of competent, experienced and resourced supply chain.
11. Communication		
When considering communication and connectivity requirements to support the repurposing of infrastructure and equipment for the production of offshore hydrogen, what issues do you regard as being a priority?		
Cross sectoral coordination Requirement for cross-sector discussion and agreement. Requirement to consider H_2 and CCS as inter-connected. Requirement to avoid the scenario where H_2 and CCU are competing to repurpose the same asset.	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance.
Public perception and opinion Explaining to the public & oil field workforce that the application of hydrogen is a way to secure the long term future of the offshore industry.	Opportunity	Industry representation / Government policy, regulatory framework guidance.

Remote operation Important for remote operation from shore for reduced OPEX and improved personnel safety. Potential for communication infrastructure to be interfaced with offshore power generation infrastructure.	Opportunity	Technical innovation..
Coordination Joined up thinking and working together is key. The way forward is to do this in HUBS and islands – have different end user / operators working together.	Challenge – transfer potential	Technical innovation./ Industry representation / Government policy, regulatory framework guidance.
Digitalisation Digitalisation is key to the control of offshore assets.	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance.
12. Synergies with oil & gas decommissioning and life extension		
When considering the repurpose of infrastructure and equipment for the production of offshore hydrogen, what quick wins or synergies do you see that could stimulate elements of the oil & gas decommissioning market whilst enabling operators and the UK Government to maximise economic value?		
Infield pipelines In-field pipelines for storage.	Challenge – novel concept / scenario	Industry representation / Government policy, regulatory framework guidance.
Requirement for clear guidance Regulators (the OGA, BEIS, Crown Estate etc…) should work with oil and gas operators to ensure clear guidance is in place for the decision-making process regarding any re-use or repurposing opportunity. Without such guidance there could be two scenarios. 1) re-use opportunities are not realised, 2) operators are slow to progress decommissioning projects while they await reuse opportunities. Clear guidance will mitigate both scenarios.	Challenge – novel concept / scenario	Industry representation / Government policy, regulatory framework guidance.
Government support Government direct support for establishing CO_2 sequestration in the form of tax rebates such as the US 45Q can build an industry that will drive decommissioning and repurposing at commercial levels.	Challenge – transfer potential	Industry representation / Government policy, regulatory framework guidance.
Deferment of decommissioning Co-use of oil and gas infrastructure with other revenue generating streams, such as hydrogen generation would enable delay in de-commissioning and help maximise economic recovery of hydrocarbons.	Challenge – potential conflict.	Industry representation / Government policy, regulatory

		framework guidance.
Project synergies Offshore work scopes to repurpose elements of infrastructure could synergise with decommissioning projects. i.e., you could remove elements of pipeline infrastructure using the same vessel and project team to repurpose a pipeline.	Opportunity	Industry representation / Government policy, regulatory framework guidance.
Ageing equipment Between the platforms there is a possibility to use machinery that is NOT>25 years old. If it is the intention to use existing machinery, platforms with a sufficient operational running hours must be identified. Do NOT use a platform that is likely to cease operation before 2030.	Challenge – novel concept / scenario	Industry representation / Government policy, regulatory framework guidance.
Different approach to decommissioning where piecemeal retirement is central. MER can be achieved by dual purposing of facilities. If different actors are involved in the H_2 generation phase, the handling of decommissioning liability should be considered and possibly transferred.	Challenge – novel concept / scenario	Industry representation / Government policy, regulatory framework guidance.
13. Other issues		
Challenges and conflicts • Subsurface storage challenges; • Synergies and conflicts between H_2 and CCS developments.	Challenge – potential conflict.	Industry representation / Government policy, regulatory framework guidance.
Inter-seasonal hydrogen storage Recent research has drawn attention to the possibilities of inter-seasonal hydrogen storage, this may be in depleted gas fields, in caverns constructed within offshore rock salt formations or within the pore space of geological formations. Repurposing of subsurface wells and reservoirs and above seabed infrastructure, not currently available for change of use, should be considered in the near future for re-use for hydrogen storage, as well as CO_2 storage.	Opportunity	Industry representation / Government policy, regulatory framework guidance.
Future developments in offshore sizing of SMR technologies. Large-scale production of hydrogen by Steam Methane Reformation or Auto-Thermal Reformation is currently only undertaken onshore. Recent consortium research in the international ELEGANCY project has investigated refinement of these processes as a step toward reformation at sufficiently compact scale for operation on offshore installations. This is a future technology, whereby methane is produced, hydrogen reformed and piped onshore with the CO_2 produced injected back into the subsurface. Regarding re-use of oil and gas infrastructure the scale of reduction in reformation plant size is currently assessed as suitable for a Floating Platform and Storage Offloading facility. However, the intention to continue refinement of the reformation technology for implementation on smaller offshore infrastructure should be part of the 'horizon scanning' for UK offshore infrastructure re-use.	Opportunity	Technical innovation.