Scotland’s Net Zero Roadmap: WP4.4 Hydrogen Production Assessment

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About Scotland’s Net Zero Roadmap and Partners

Scotland’s Net Zero Roadmap (SNZR) is Innovate UK funded project number 75206. The aim of the project is to develop a roadmap that sets out how Scottish industry can move towards Net Zero by 2045, based on exploring a number of decarbonisation scenarios. The project focuses on a cluster of industrial activity on the East Coast of Scotland which covers many of the largest industrial sites across a range of sectors and 80% of Scotland’s industrial CO_2 emissions.

SNZR is led by NECCUS and other project partners are Costain Limited, Altrad Babcock Limited, Halliburton Manufacturing and Services Limited, Aker Solutions Limited, Wood Group UK Limited, Energy System Catapult Limited, Net Zero Technology Centre, Storegga, Optimat Limited, The University of Edinburgh and The University of Strathclyde.

Executive Summary

Wood has undertaken Work Package 4.4 – Hydrogen Production for Scotland's Net Zero Roadmap (SNZR) project. This involves the assessment of hydrogen demands for industrial fuel-switching within the North East Cluster under each of six main scenarios. Wood has determined typical costs for new national or regional hydrogen production hubs. Both blue hydrogen (generated through reformation of fossil-fuels, with capture and storage of carbon dioxide) and green hydrogen (generated through electrolysis of water using renewable electricity) were considered as viable options.

28 industrial emitters were approached under Work Package 2 with a Request for Information (RFI) to obtain site emissions data relating to the different processes on site. Energy use data was also gathered for the sites through the RFIs. This data was used to estimate hydrogen demands based on hydrogen fuel-switching for different site operations and in turn, helped build the different hydrogen demand profiles for the six scenarios.

This report outlines the overall hydrogen demand profiles for each of the scenarios. Based on the scenario, hydrogen hubs have been assumed in different locations to provide both blue and green hydrogen. The required blue and green hydrogen production from the hubs was in turn used to determine the number of reformers and electrolyser systems to meet the blue and green hydrogen demand respectively. The Total Installed Cost was then determined for the blue and green hydrogen production facilities for each of the scenarios.

This report also assesses the additional CO_2 captured from the new blue hydrogen production facilities. As no blue hydrogen demand has been identified for Scenarios 2, 5 and 6, the assessment of CO_2 captured from new blue facilities has not been carried out for these scenarios. As well as meeting the industrial hydrogen demand, the CO_2 captured has also been estimated for meeting both average and peak domestic hydrogen demand. The captured CO_2 rates have been broken down by hydrogen hub.

The report should be considered as one element of the technical definition required as input into the scenario modelling exercise in Work Package 5 and not taken as providing specific results or conclusions outside of the broader SNZR project.

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Approved By: Tony Tarrant	**Date:** 9th December 2022

1 Introduction

Wood has completed the Hydrogen Production Model as part of Work Package WP4.4 – Hydrogen Production for Scotland's Net Zero Roadmap (SNZR) project. This involved the assessment of hydrogen demands for industrial fuel-switching within the North East Cluster under each of six main scenarios. Wood has determined typical costs for new national or regional hydrogen production hubs as part of this assessment. Both blue hydrogen (generated through reformation of fossil-fuels, with capture and storage of carbon dioxide) and green hydrogen (generated through electrolysis of water using renewable electricity) are considered as viable options.

Emitter data was collected under Work Package 2 from the 28 site emitters using Request for Information forms. The form allowed for gathering of emission data, which was broken down by process, as well as energy usage for the site. This data was compiled into a master spreadsheet which listed all 28 industrial emitters – this spreadsheet was used as the basis for creating the hydrogen production model. Each site was systematically worked through by the Wood team and other Work Package 4 partners to decide the most appropriate decarbonisation technology for each site and the feasibility of the site deploying the technology. Where hydrogen fuel-switching was deemed as an appropriate technology, a hydrogen fuel demand was calculated based on the site information provided using the assumptions outlined in Section 2. This hydrogen fuel demand was used as the basis to build the profiles for the different scenarios.

As previously mentioned, six scenarios have been defined for the SNZR project, all outlining different paths to decarbonisation. The following gives a brief description of the scenarios, highlighting the key characteristics relating to each.

Scenario 1 is the 'Infrastructure Led' scenario, which involves re-using the existing infrastructure and building out of existing decarbonising projects. Three blue hydrogen production hubs are required, and they are located at St. Fergus, Grangemouth and Mossmorran, with St. Fergus being the main hydrogen producer. A green hydrogen production hub in Aberdeen is also required to meet demand for green hydrogen. As this scenario maximises use of pre-existing assets and strengths, it likely allows for most cost-efficient, low-risk decarbonisation roll-out. However, the slower rate of decarbonisation could hamper efforts to meet the Net Zero target by 2045. See **Scenario 1: Infrastructure Led** for more detail.

Scenario 2 is the 'Soft Start' scenario and focuses mainly on simple fuel-switches and efficiency improvements, with CCUS (other than Acorn) being built later in the pathway. The scenario allows for some Net Zero progress to be maintained but at a slower overall pace. No new blue or green hydrogen production facilities are envisaged as part of this scenario. See **Scenario 2: Soft Start** for more detail.

Scenario 3 is the 'Regional Hydrogen Network' scenario and involves the development of local (sub-regional) hydrogen facilities with CCUS, fed by the National Transmission System, which is largely retained for natural gas, although with some re-purposing to CO_2. This scenario looks at a fast adoption of hydrogen, with blue production early and then green hydrogen later on. Similar to Scenario 1, three blue hydrogen hubs are required: St. Fergus, Grangemouth and Mossmorran. However, Grangemouth is the largest hydrogen producer as each hub serves the local region, with Grangemouth serving the greatest number of industrial emitters. Two green hydrogen hubs are also required to meet green hydrogen demand: one is located in Aberdeen and the other in Edinburgh. See **Scenario 3: Regional Hydrogen Network** for more detail.

Scenario 4 is the 'National Hydrogen' scenario, which involves the development of national hydrogen production centres with hydrogen production growing rapidly (similar to Scenario 3). In this scenario, two blue hydrogen hubs are required in St. Fergus and Grangemouth, with St. Fergus being the main national hydrogen production centre. A green hydrogen production hub is also required in Aberdeen to meet green hydrogen demand. See **Scenario 4: National Hydrogen** for more detail.

Scenario 5 is the 'Renewables Push' scenario, which involves investment in renewables and green hydrogen infrastructure. Green hydrogen production grows rapidly in this scenario and is linked in Scotland to the build-out of offshore wind. Two green hydrogen hubs, one in Aberdeen and the other in Fife, are required. See **Scenario 5: Renewables Push** for more detail.

Scenario 6 is the 'CO_2 Shipping' scenario, which focuses on the scale of CO_2 storage potential in Scotland and need for CO_2 shipping to stores across Europe, leading to a rapid build out of shipping infrastructure helping to reduce costs. A single green hydrogen production hub in Aberdeen is required to meet green hydrogen demand. See **Scenario 6: CO2 Shipping** for more detail.

This report details the breakdown of blue and green hydrogen demand for each scenario. These demands are used to determine the number of reformers at blue hydrogen facilities and alkaline electrolyser systems at green hydrogen facilities. Using the standard production block costs outlined in Section 2**,** the Total Installed Cost (TIC) is determined for each hydrogen hub for each scenario.

In addition, the CO_2 captured from the reformers at the blue hydrogen hubs has been estimated for the scenarios which involve blue hydrogen production. This calculation accounts for both the hydrogen required for industrial fuel-switching and for meeting average and peak domestic heating demands (residential and commercial). It is important to note that additional hydrogen demands that may arise from other industries, such as transport and agriculture, have not been accounted for when estimating the CO_2 captured from the reformers. Exports to other parts of the UK or Europe have also been excluded from this analysis.

The data presented in this report provides one element of the technical input for the system modelling exercise in Work Package 5.

2 Basis and Assumptions for Hydrogen Model

Key assumptions used to build the model include:

- For the purposes of forecasting hydrogen fuel-switching demands, assumed industrial emitters maintain current fuel feed rates through to 2045.
- Higher Heating Value (HHV) has been used for both hydrogen and natural gas when calculating fuel-switching demands.
- For calculation of TIC for blue and green hydrogen production facilities, domestic demand has been excluded from this calculation – only the industrial demand from the 28 emitters has been used as the basis.
- For calculation of green hydrogen cost blocks, alkaline electrolyser technology has been selected (PEM is currently slightly more expensive).
- Fugitive emissions of CO_2 have not been accounted for in the model.
- 100% of the natural gas feed is combusted in gas-fired boilers and turbines (no incomplete combustion).
- Sites operate for 8,424 hrs/yr (assuming 14-day shutdown each year). This allows for a more conservative estimate of hydrogen demand.
- Approximation that for every 1kg of natural gas burned, 3 kg of CO_2 is produced.
- For the calculation of peak average natural gas demand, assume the ratio of peak to average natural gas demand is 1.83, based on historic data.
- For each blue hydrogen production facility, it is assumed that the conversion of industrial users is completed in a minimum of 3 years after start-up. Thus, the hydrogen production rate grows linearly to maximum production after 3 years unless there is a delay in technology availability.
- 100% Hydrogen Turbines will not be available for commercial deployment until after 2030. Thus, some hydrogen demand at the hubs will be delayed, namely St. Fergus.
- For each green hydrogen production facility, it is assumed that the conversion of industrial users is completed 4 years after start-up. Thus, the hydrogen production rate grows linearly to maximum production after 4 years.

Table 1 and Table 2 show the Cost Blocks used to estimate the cost of Blue and Green Hydrogen respectively – the development of these costs is described in the Hydrogen Technology Assessment Report, 522162-8820-RP-01. These blocks have been used to develop a Class 5 cost estimate for each of the blue and green hydrogen production facilities for each of the scenarios.

Individual assumptions for each scenario are stated throughout the report.

Table 1: Cost Blocks for Blue Hydrogen

From	Production Block (TPD)	TIC (£M)
Mid 2020s	500	325
2030s	1000	500

Table 2: Cost Blocks for Green Hydrogen

From	Electrolyser System (MWe)	TIC (£M)
Mid 2020s	100	170
2030s	200	220

Electrolyser system capacities are based on the electrical input to the facility.

3 Overall Hydrogen Demand Profiles for Scenarios

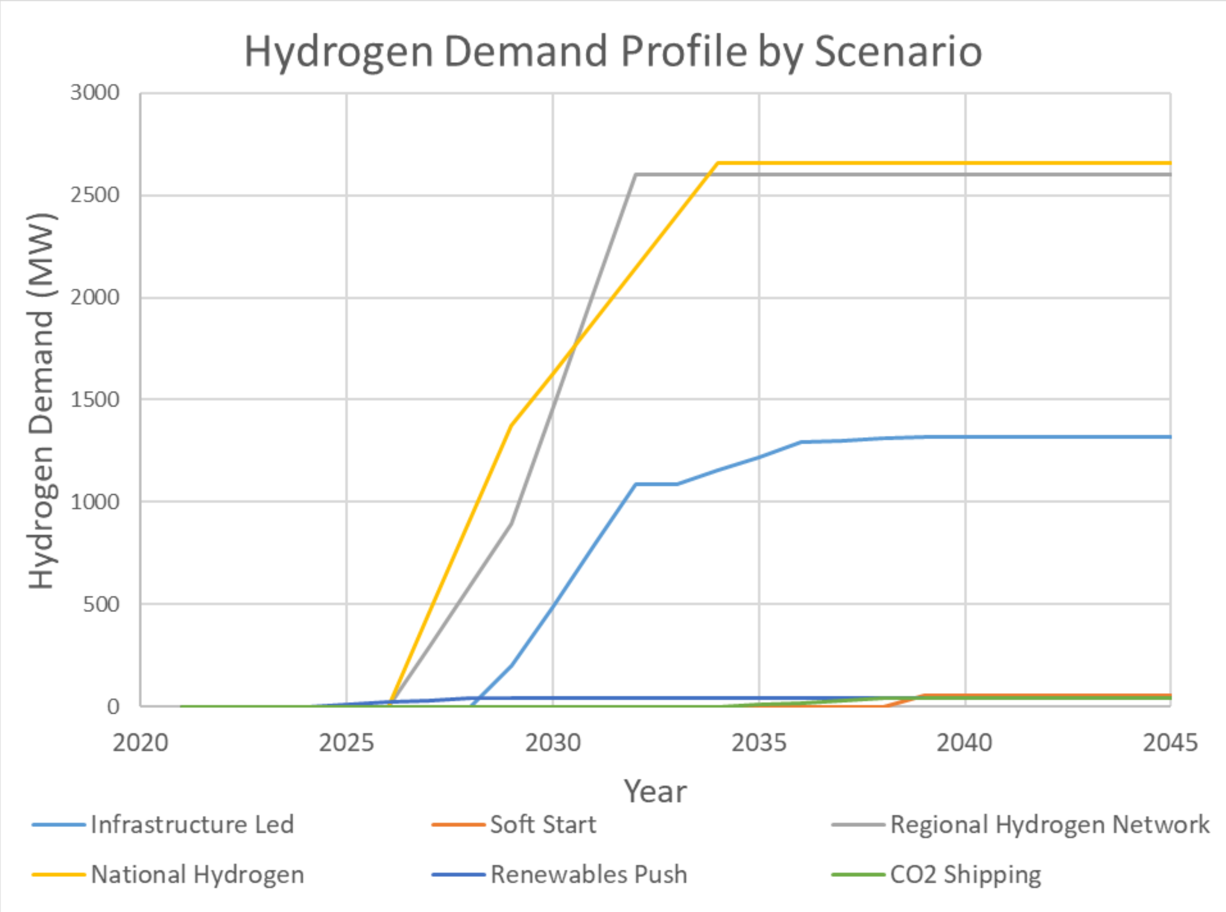

Figure 1 - Hydrogen Demand Profiles by Scenario

Figure 1 illustrates the hydrogen demand profiles for each scenario through to 2045 - the target date to reach Net Zero. As expected, the Soft Start, Renewables Push and CO_2 Shipping scenarios have the lowest overall hydrogen demands – this is due to CO_2 capture and renewable electricity being widely adopted across the emitters for these scenarios. There was, however, a small green hydrogen industrial demand for both the Renewables Push and CO_2 Shipping scenarios (see **Scenario 5: Renewables Push** and **Scenario 6: CO2 Shipping**). The Soft Start scenario has a small hydrogen demand for the Grangemouth refinery (see **Scenario 2: Soft Start** of the report) related to retrofit of an existing reformer at the refinery. For the Infrastructure Led scenario, the slow build-out of the hydrogen production centres gives rise to the smooth hydrogen demand curve, with the peak demand of 1321 MW being reached by 2039. As expected, the Regional Hydrogen Network shows a faster adoption of hydrogen due to the rapid build out of the hydrogen production hubs, with the total demand levelling out at 2604 MW by 2032. The National Hydrogen scenario follows a similar trajectory to the Regional Hydrogen scenario, with a slightly faster rate of hydrogen production due to the focus on large-scale production at St Fergus. The National Hydrogen scenario reaches peak demand by 2034 with a demand of 2658 MW.

Table 3 – Total Hydrogen Demand for Scenarios

Scenario	H_2 Total Demand (MW)
Infrastructure Led	1321
Soft Start	51
Regional H2 Network	2604
H2 Economy	2658
Renewables Push	41
CO_2 Shipping	38

Hydrogen demand profiles relate to MW of higher heating value.

4 Overall CO_2 Captured from New Blue Hydrogen Facilities

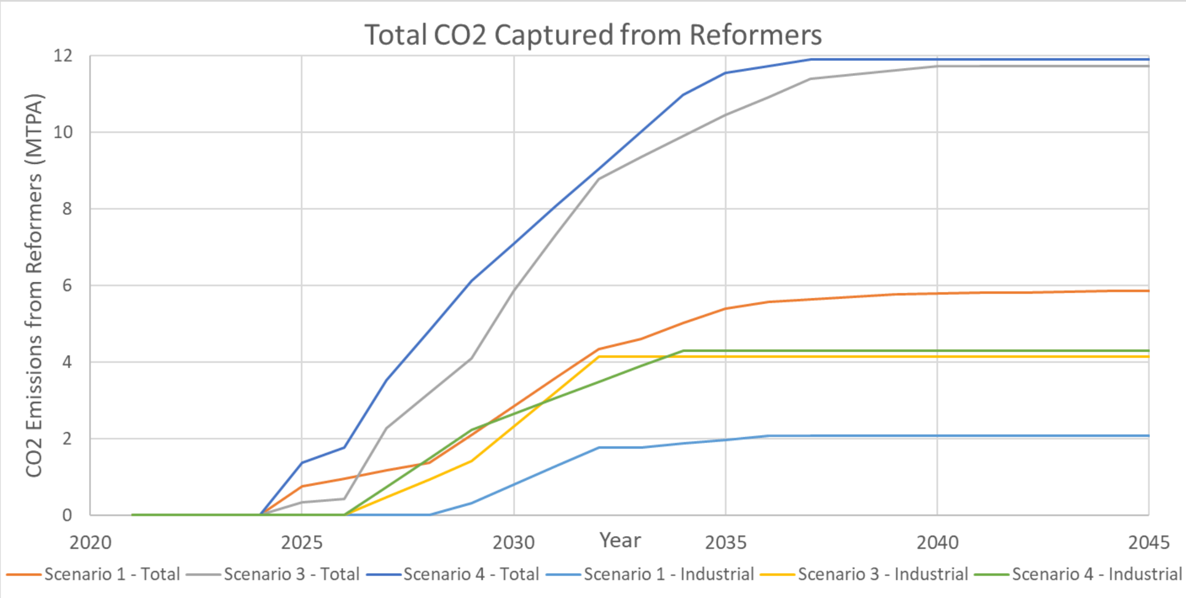

Figure 2 - Total CO_2 Captured from Reformers

Figure 2 illustrates the total CO_2 captured from the reformers in the new blue hydrogen production facilities for Scenarios 1, 3 and 4. Scenarios 2, 5 and 6 do not include new blue hydrogen facilities as part of the scenario and hence will not be discussed in this section. The chart illustrates the total CO_2 generated to meet the combined industrial and domestic hydrogen demand for the three scenarios denoted as total. The chart also shows the proportion of this CO_2 generated in producing hydrogen for industrial use by the existing emitters considered in this project.

The domestic hydrogen demand was calculated based on using the average annual gas demand forecast for the SGN network from 2021/22, which factored in both residential and commercial buildings. This value was then scaled down to the different hydrogen production hubs based on the customers served in the region and the industrial demand for each scenario. It was assumed that for each scenario, an initial blending of 20% H_2 and 80% natural gas was feasible immediately after initial production from the hydrogen hubs, with a gradual build out to 100% H_2 for domestic use over a ten-year period.

To calculate the CO_2 captured during hydrogen production, a mass balance was carried out across a typical steam methane reformer. Table 4 below highlights the total CO_2 captured by 2045 for each of the scenarios for industrial and total. As expected, both Scenarios 3 and 4 give rise to the highest CO_2 rates. Scenario 1 has a much lower value for total CO_2 captured due to the significantly lower hydrogen demand for the scenario. For further details on the breakdown of CO_2 captured by location for the scenarios, see Sections 5.4, 7.4 and 8.4 for Scenarios 1, 3 and 4 respectively.

Table 4 – Total CO_2 Captured from Blue Hydrogen Facilities by 2045

Scenario	Total CO_2 Captured (MTPA)	
	Industrial	Total (Industrial +Domestic)
Scenario 1	2.1	5.8
Scenario 3	4.1	11.7
Scenario 4	4.3	11.9

5 Scenario 1: Infrastructure Led

5.1 Hydrogen Demand Profile

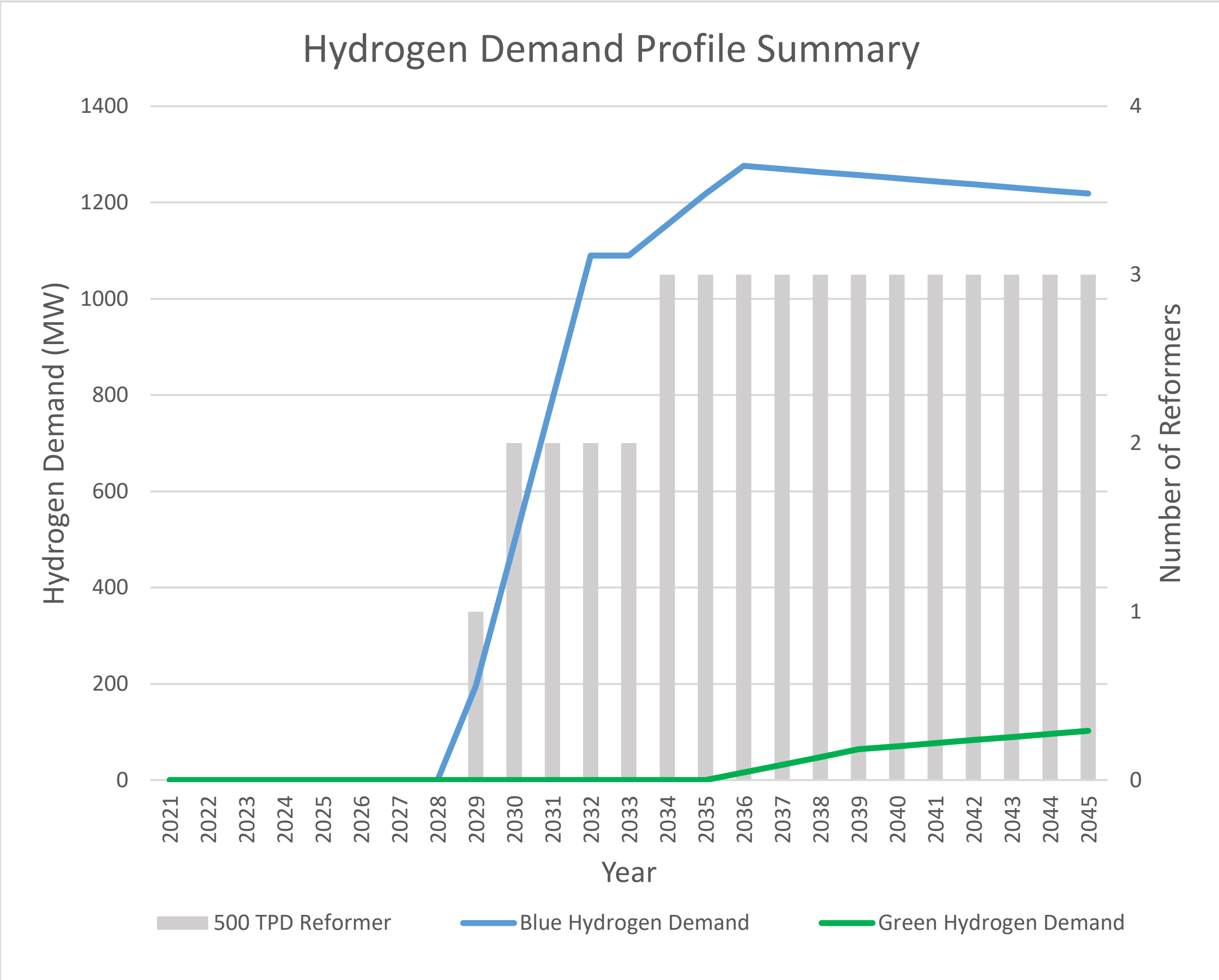

Figure 3 - Hydrogen Demand Profile for Scenario 1

Figure 3 illustrates the breakdown of hydrogen demand for Scenario 1 in terms of blue and green hydrogen. The chart also indicates the number of 500 TPD reformers that are required to meet the blue hydrogen demand. Table 5 highlights the key events for the Scenario 1 timeline. The chart shows that industrial blue hydrogen production starts in Grangemouth in 2029, where the hydrogen demand increases up to 782 MW by 2033. Additional blue hydrogen production then starts at 2030 in St. Fergus, where blue hydrogen production gradually increases up to 308 MW by 2033. Blue hydrogen production is already expected in 2025 at St. Fergus through the Acorn Hydrogen Project for commercial and domestic use, but due to 100% hydrogen turbines not being available until 2030 this study does not see a demand for industrial users until after that date. The final blue hydrogen production comes from Mossmorran which begins in 2034 and increases up to 193 MW by 2037. From 2037 through to 2045, blue hydrogen is gradually replaced by green hydrogen through the Dolphyn project, where the total green hydrogen demand is 102 MW by 2045.

An assumption that was made for green hydrogen demand was that 5% of the total blue hydrogen demand by 2045 would be replaced by green hydrogen – this was in addition to the existing industrial green hydrogen demand indicated by the emitters. This assumption allows for a slower ramp-up in green hydrogen than for the two hydrogen economy scenarios. Refer also to Section 7.1 for further discussion.

Table 5 – Key Events for Scenario 1

Event	Year
Blue hydrogen production starts at St. Fergus through the Acorn H2 project	2025
Blue hydrogen production starts at Grangemouth	2029
Blue hydrogen production starts at St. Fergus for industrial users	2030
Blue hydrogen production starts at Mossmorran	2034
Green hydrogen production starts from offshore wind supplied through the Dolphyn project (15km offshore Aberdeen)	2036

5.2 Cost of Blue Hydrogen

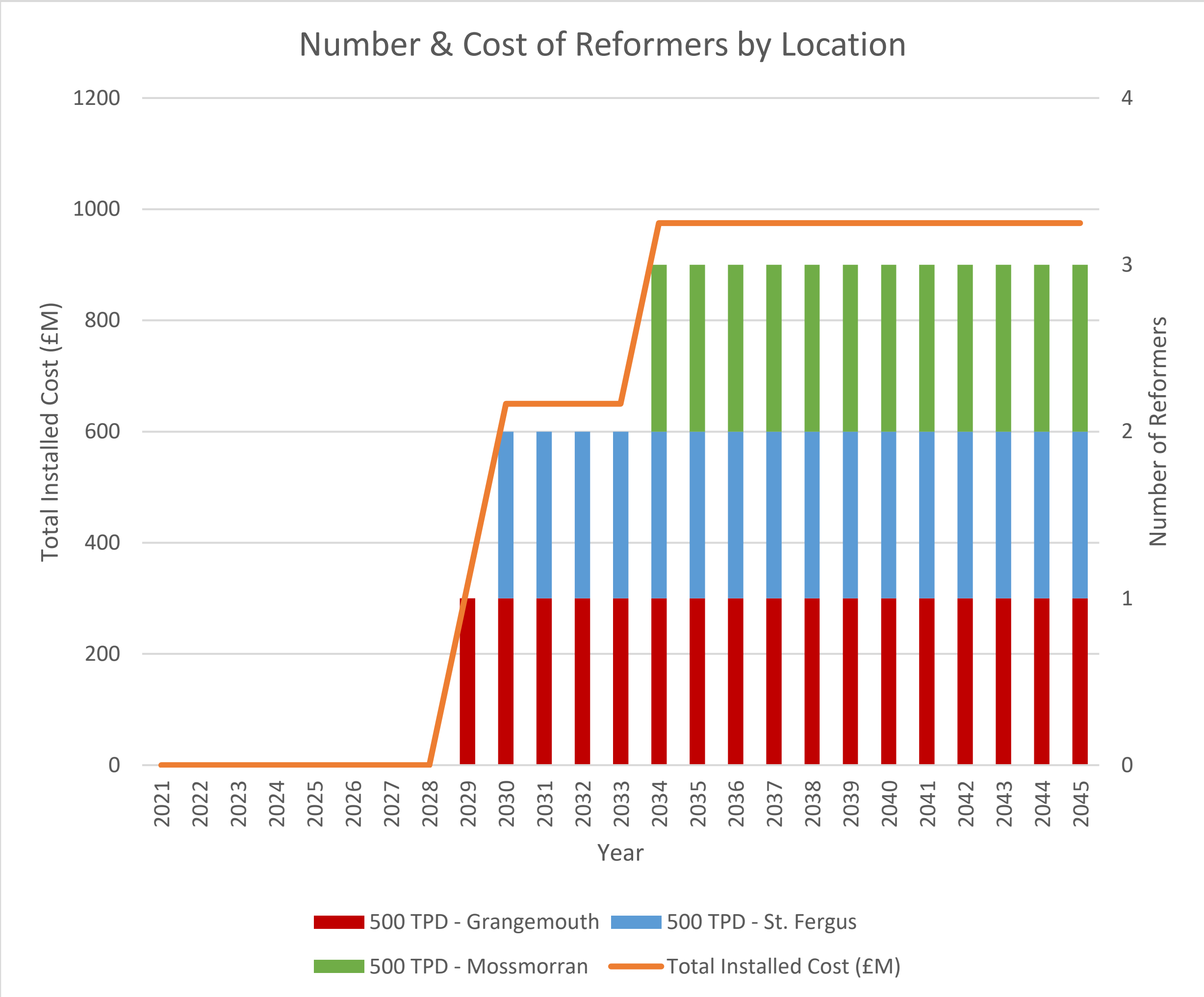

Figure 4 - Scenario 1: Total Installed Cost for Blue Hydrogen

Figure 4 illustrates the TIC for the blue hydrogen production facilities with time for Scenario 1 and Figure 5 indicates the share of TIC by location. As can be seen from the chart, a 500 TPD reformer is assumed at Grangemouth from 2029 with a TIC of £325M. In 2030, a 500 TPD reformer is assumed at St. Fergus with a TIC of £325M. Finally, a 500 TPD reformer is assumed at Mossmorran from 2034 to meet the overall blue hydrogen demand with a TIC of £325M. Therefore, overall, a total TIC of £975M is predicted for the blue hydrogen production facilities by 2045.

Naturally, the location of reformers will depend on a number of factors including the incentives for investors, availability of local support infrastructure, and the growth of associated domestic hydrogen demand in different locations. The profile and distribution of costs above indicates one credible outcome for hydrogen supply in Scenario 1.

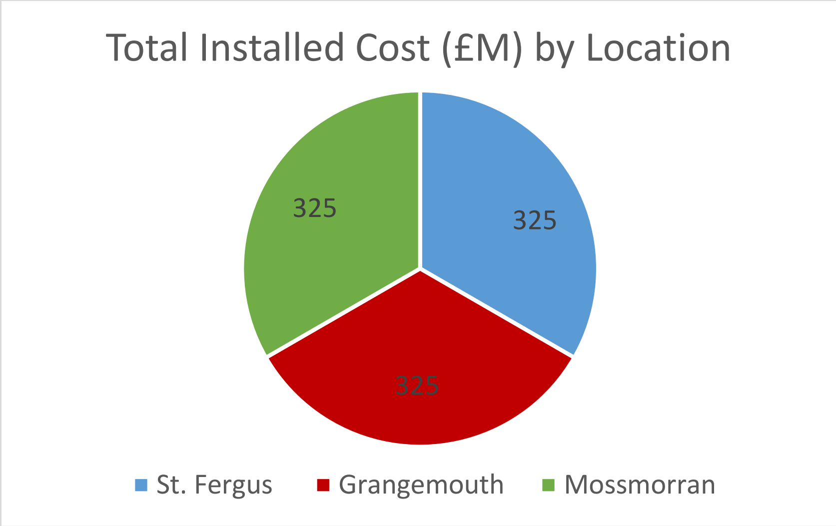

Figure 5 – Scenario 1: Breakdown of Cost by Location

5.3 Cost of Green Hydrogen

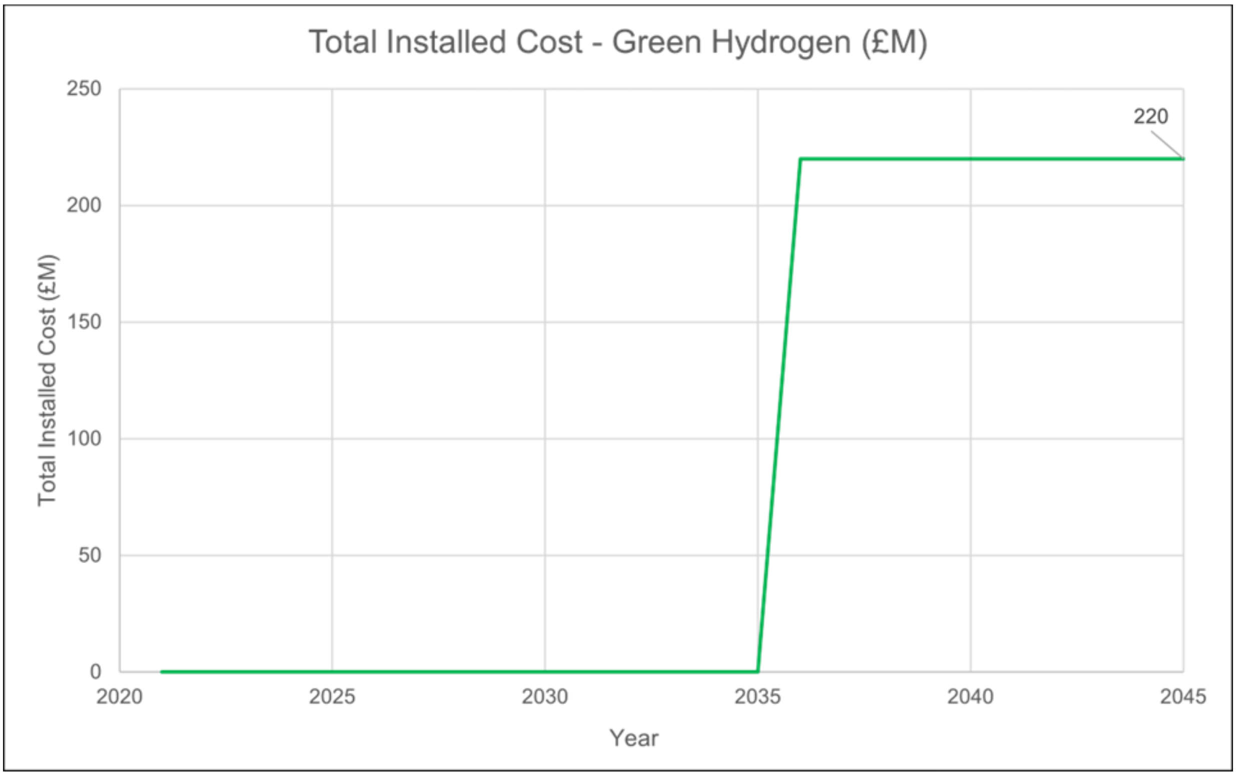

Figure 6 - Scenario 1: Total Installed Cost for Green Hydrogen

Figure 6 illustrates the TIC for green hydrogen production for Scenario 1. The TIC of £220M corresponds to the construction of a single 200 MWe electrolyser system, capable of meeting the total green hydrogen demand. The green hydrogen production, beginning in 2036, is assumed to be provided through the Dolphyn project, near Aberdeen, but could easily be another project of similar scale on the North East coast.

5.4 CO_2 Captured from New Blue Hydrogen Facilities

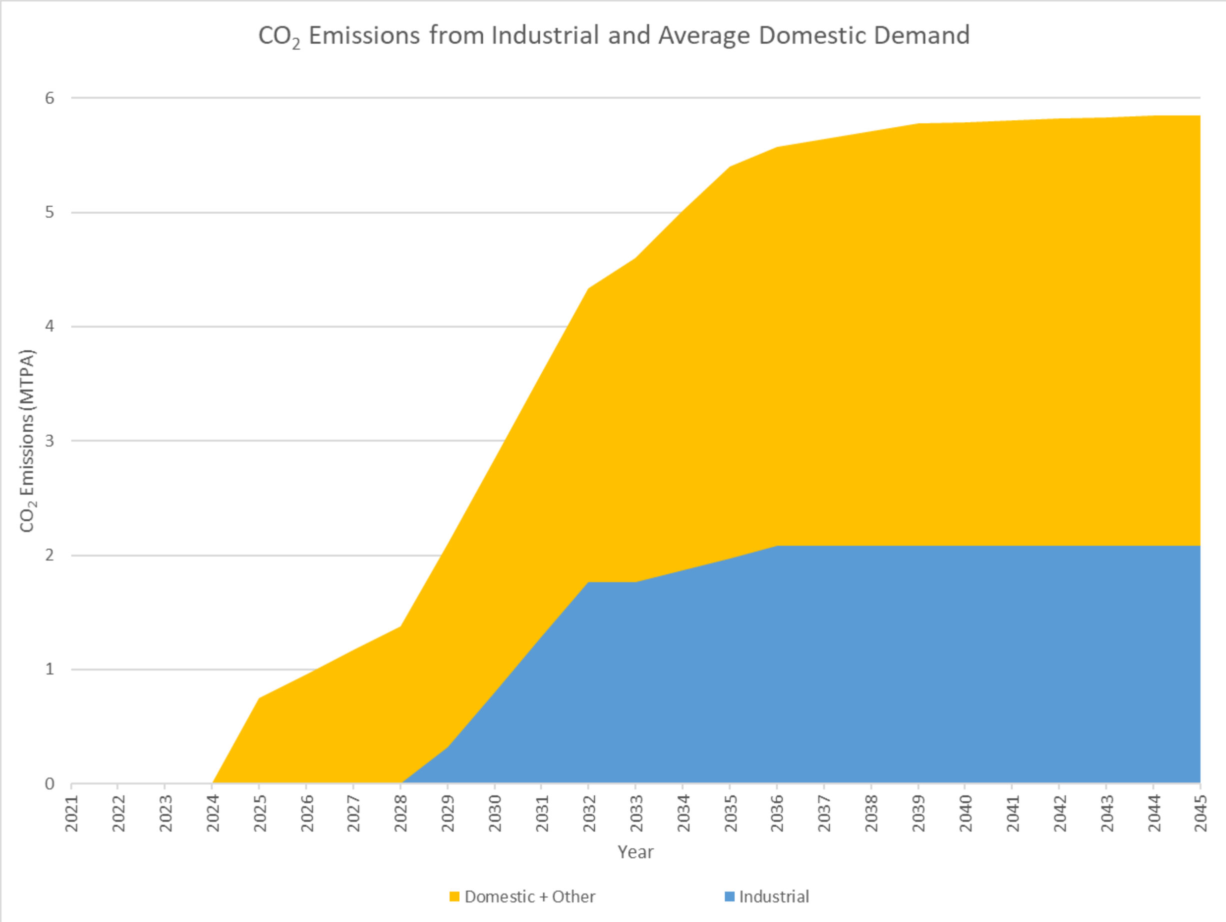

Figure 7 – Scenario 1: Industrial CO_2 Emissions from Industrial and Domestic Demand (all locations)

Figure 7 demonstrates the make-up of Blue hydrogen CO_2 emissions from the demand calculated for industrial users and domestic + other users. This figure shows that domestic demand starts earlier due to our assumptions of when hydrogen will be available, this is then compounded with significant CO_2 emissions from hydrogen manufactured for industrial users. CO_2 emissions start to plateau around 2036, the industrial emissions constitute around a third of all CO_2 emissions in this scenario by 2045.

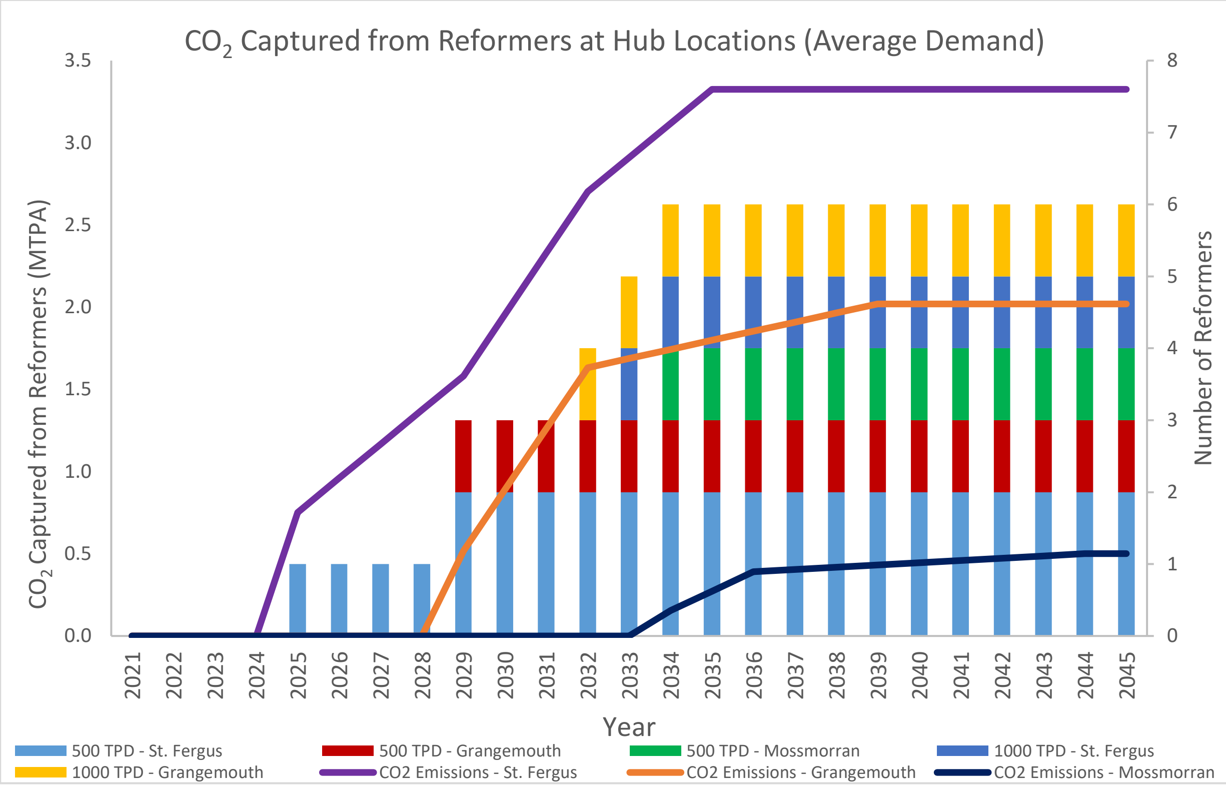

Figure 8 - Scenario 1: Average CO_2 Captured from Reformers by Location

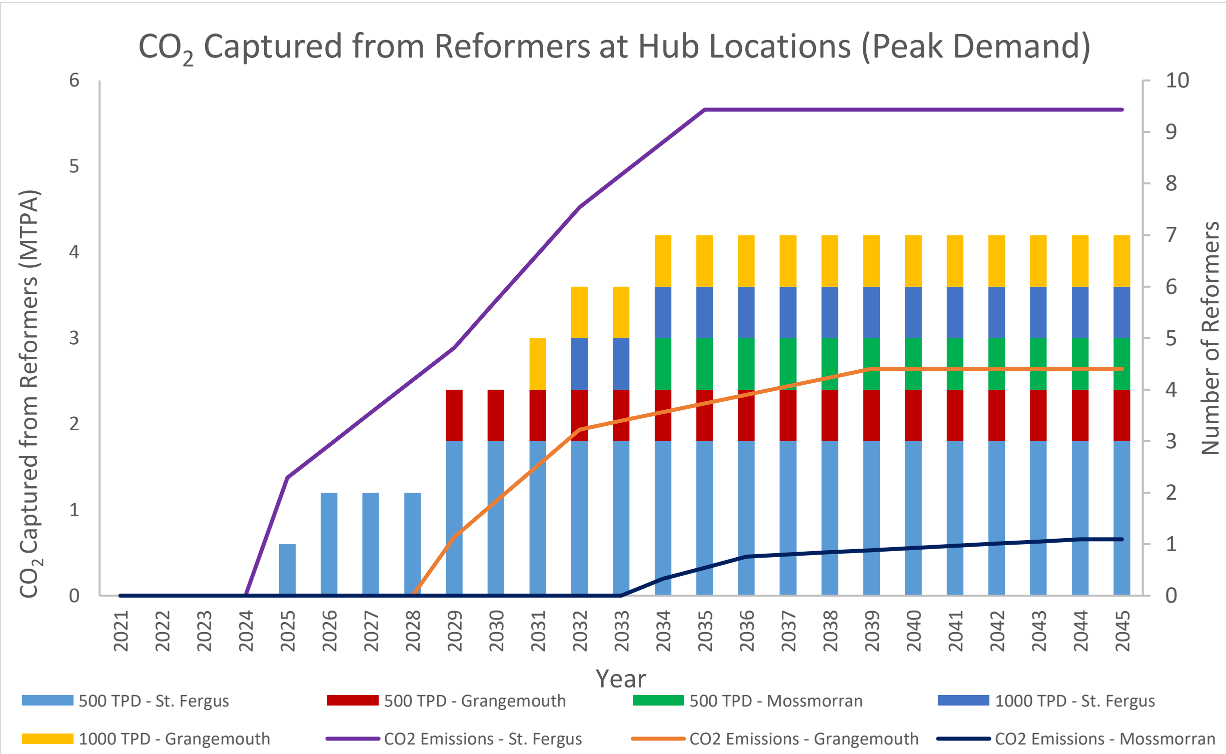

Figure 9 - Scenario 1: Peak CO_2 Captured from Reformers by Location

Figure 8 and Figure 9 show the CO_2 captured from the new blue hydrogen production facilities required for industrial and domestic demand, broken down by location for both average and peak hydrogen demand respectively. Table 6 provides the number of reformers for each location for average and peak demand. More reformers are shown in this table, compared to Figure 4, because the full impact of both industrial and domestic demand is considered when determining the CO_2 production rate.

As expected, the highest average and peak CO_2 rates are generated at St. Fergus as it is the main hydrogen producer for this scenario. Looking at just the average CO_2 rates, St. Fergus captures the most at 3.3 MTPA by 2045 followed by Grangemouth and then Mossmorran at 2.0 MTPA and 0.5 MTPA respectively.

Peak values are provided in this report for the case where the maximum rate of hydrogen use is covered by installed capacity, with limited availability of storage facilities. The authors expect this is less likely than the long-term provision of storage facilities, but hydrogen storage is outside the scope of this study.

Table 6 – Number of Reformers for Average and Peak Demand

Location	Reformer Size (TPD)	Number of Reformers	
		Average	Peak
St. Fergus	500	2	3
	1000	1	1
Grangemouth	500	1	1
	1000	1	1
Mossmorran	500	1	1
	1000	0	0

6 Scenario 2: Soft Start

The following event details the industrial hydrogen demand for this scenario.

Table 7: Key Event for Scenario 2

Event	Year
Post-combustion retrofit for the existing Grangemouth SMR	2039

Whilst broader use of hydrogen is not incentivised in this scenario, we have assumed that the Grangemouth site will take advantage of existing hydrogen capacity to fuel-switch some internal applications. This will occur once a CO_2 export pipeline is operational from the area. The existing unit has a capacity of 110 TPD hydrogen and we have assumed that one third of that (36 TPD) is available for fuel-switching on the refinery.

Therefore, there is no requirement for any additional blue or green hydrogen production for this scenario and so this scenario will not be discussed any further.

7 Scenario 3: Regional Hydrogen Network

7.1 Hydrogen Demand Profile

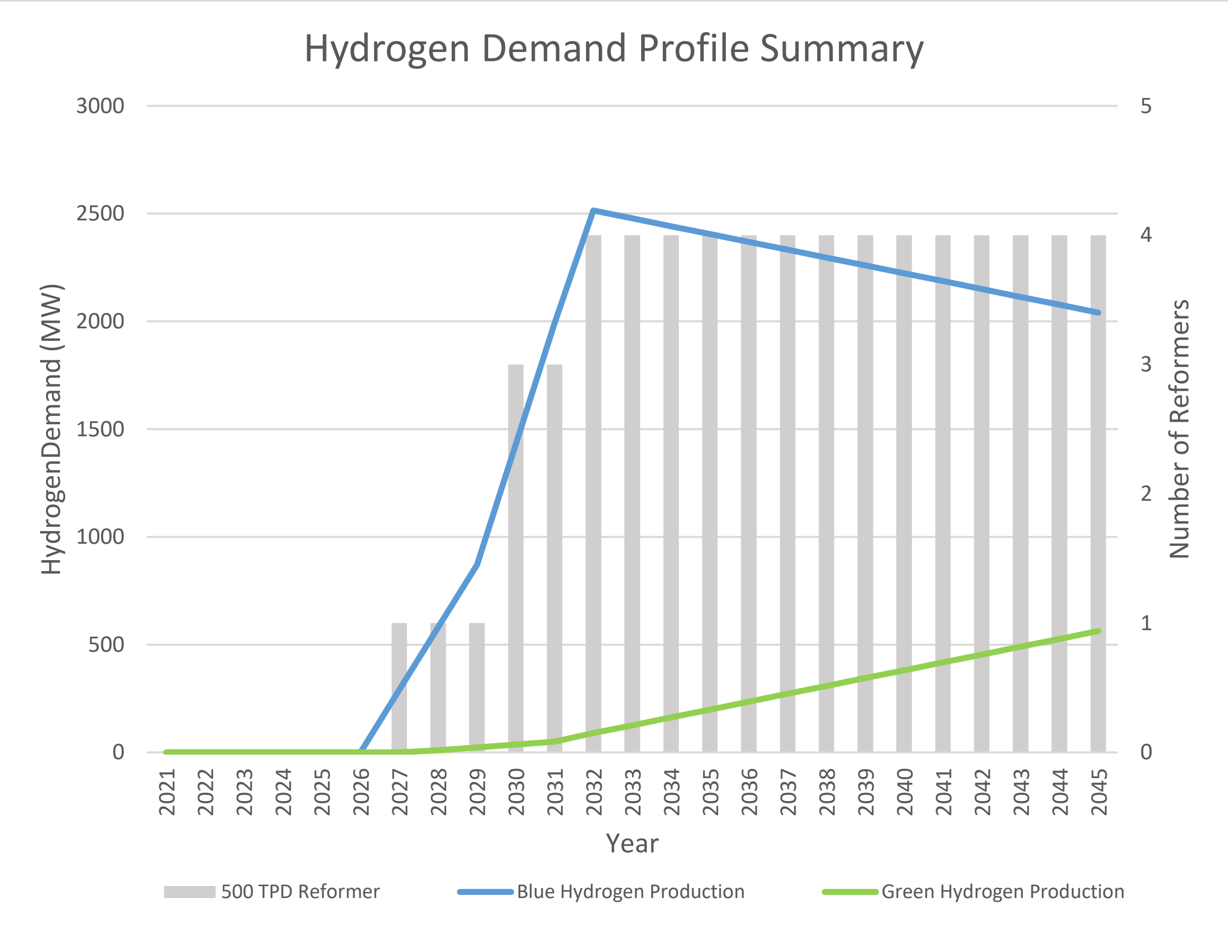

Figure 10 - Hydrogen Demand Profile for Scenario 3

Figure 10 illustrates the breakdown of hydrogen demand for Scenario 3 in terms of blue and green hydrogen. The chart also indicates the number of 500 TPD reformers that are required to meet the blue hydrogen demand. Table 8 highlights the key events for the Scenario 3 timeline. In Scenario 3, blue hydrogen production at Grangemouth commences earlier – production begins in 2027. This leads to a sharp increase in hydrogen production to 2030, when Mossmorran and St. Fergus start to produce blue hydrogen. Similar to Scenario 1, blue hydrogen production starts in 2025 at St. Fergus through the Acorn Hydrogen Project for commercial and domestic users. The blue hydrogen demand peaks at 2515 MW in 2032 before being gradually replaced by green hydrogen through the Dolphyn Project, which begins producing green hydrogen in 2028. A small demand for green hydrogen, for the North British Distillery Company, is met by a local green hydrogen hub in Edinburgh.

An assumption has been made for green hydrogen demand whereby 20% of the total blue hydrogen demand by 2045 would be replaced by green hydrogen demand – this was in addition to the existing industrial green hydrogen demand indicated by the emitters. This assumption aligns with projections published by the ORE Catapult (https://ore.catapult.org.uk/?orecatapultreports=offshore-wind-and-hydrogen-solving-the-integration-challenge).

Table 8 - Key Events for Scenario 3

Event	Year
Blue hydrogen production starts as St. Fergus through the Acorn H2 project	2025
Blue hydrogen production starts at Grangemouth	2027
Green hydrogen production from offshore wind supplied through the Dolphyn project (15km offshore Aberdeen)	2028
Green hydrogen production in Edinburgh	2029
Blue hydrogen production starts at Mossmorran and St. Fergus for industrial users	2030

7.2 Cost of Blue Hydrogen

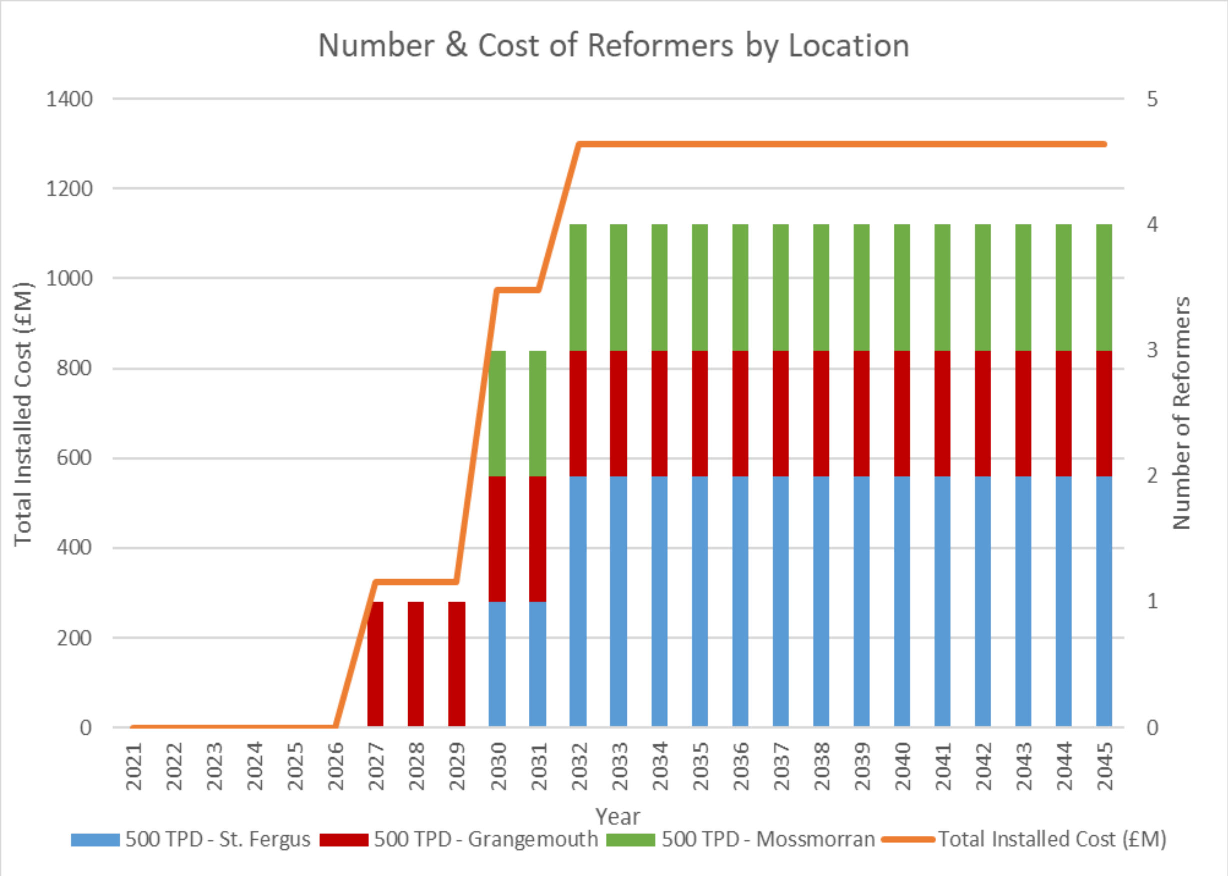

Figure 11 - Scenario 3: Total Installed Cost for Blue Hydrogen

Figure 11 illustrates the TIC for the blue hydrogen production facilities with time for Scenario 3 and Figure 12 indicates the share of TIC by location. As can be seen from the chart, one 500 TPD reformer is assumed at Grangemouth in 2027. In addition, two 500 TPD reformers are assumed at St. Fergus – one in 2030 and the other in 2032 with a TIC of £650M. Finally, a single 500 TPD reformer is assumed at Mossmorran in 2030 with a TIC of £325M. Therefore, overall, a TIC of £1,300M is predicted for the blue hydrogen production facilities by 2045.

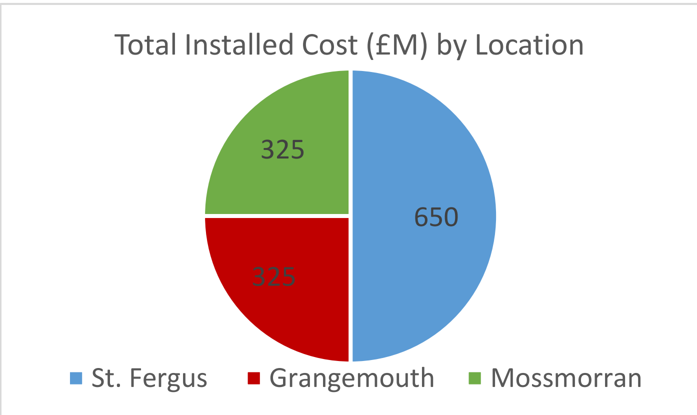

Figure 12 – Scenario 3: Breakdown of Cost by Location

7.3 Cost of Green Hydrogen

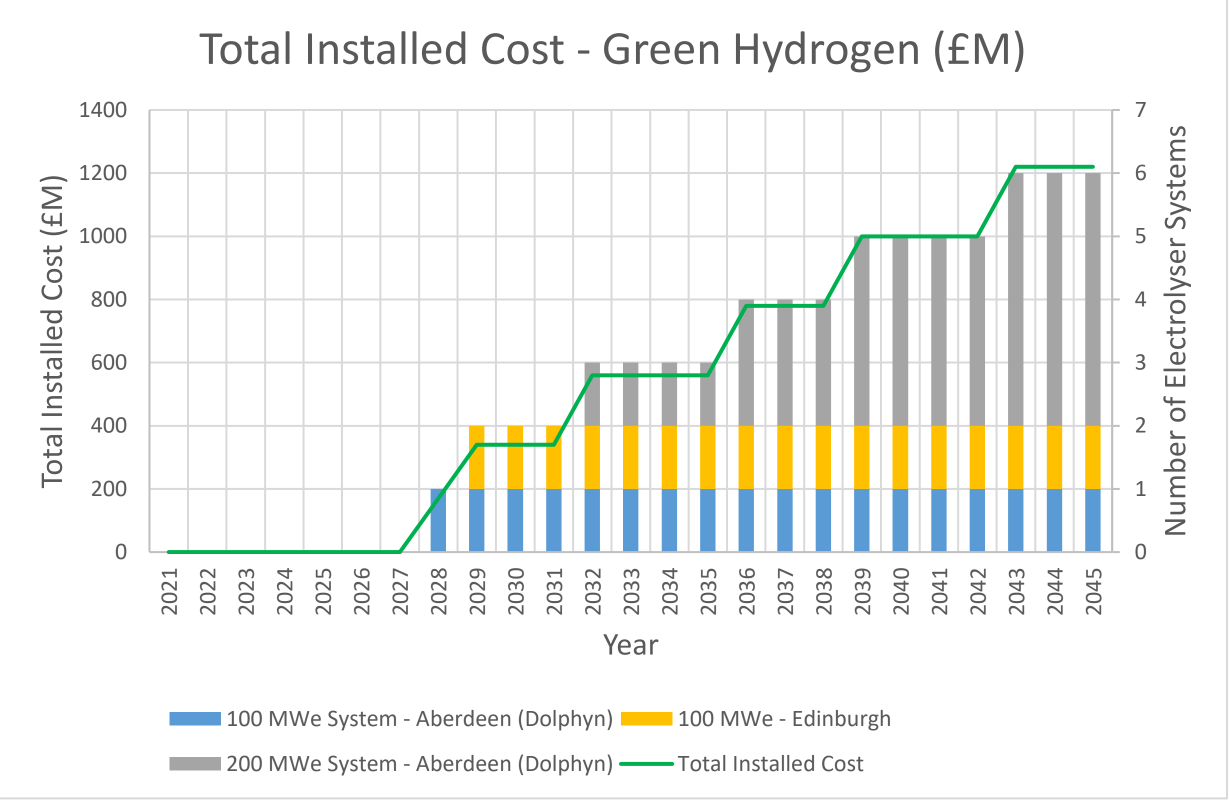

Figure 13 - Scenario 3: Total Installed Cost for Green Hydrogen

Figure 13 illustrates the TIC for green hydrogen production for Scenario 3. The chart shows that green hydrogen is initially produced by a 100 MWe electrolyser system at Aberdeen through the Dolphyn project in 2028 – the TIC for this is £170M. A second 100 MWe system is then required to produce green hydrogen for the North British Distillery Company in Edinburgh from 2029, again with a TIC of £170M. From 2034 through to 2045, an additional four 200 MWe electrolyser systems are required at the Aberdeen hub to meet the additional green hydrogen demand – this equates to a TIC of £880M. Therefore, an overall TIC of £1,220M is predicted for the green hydrogen production facilities by 2045.

7.4 CO_2 Captured from New Blue Hydrogen Facilities

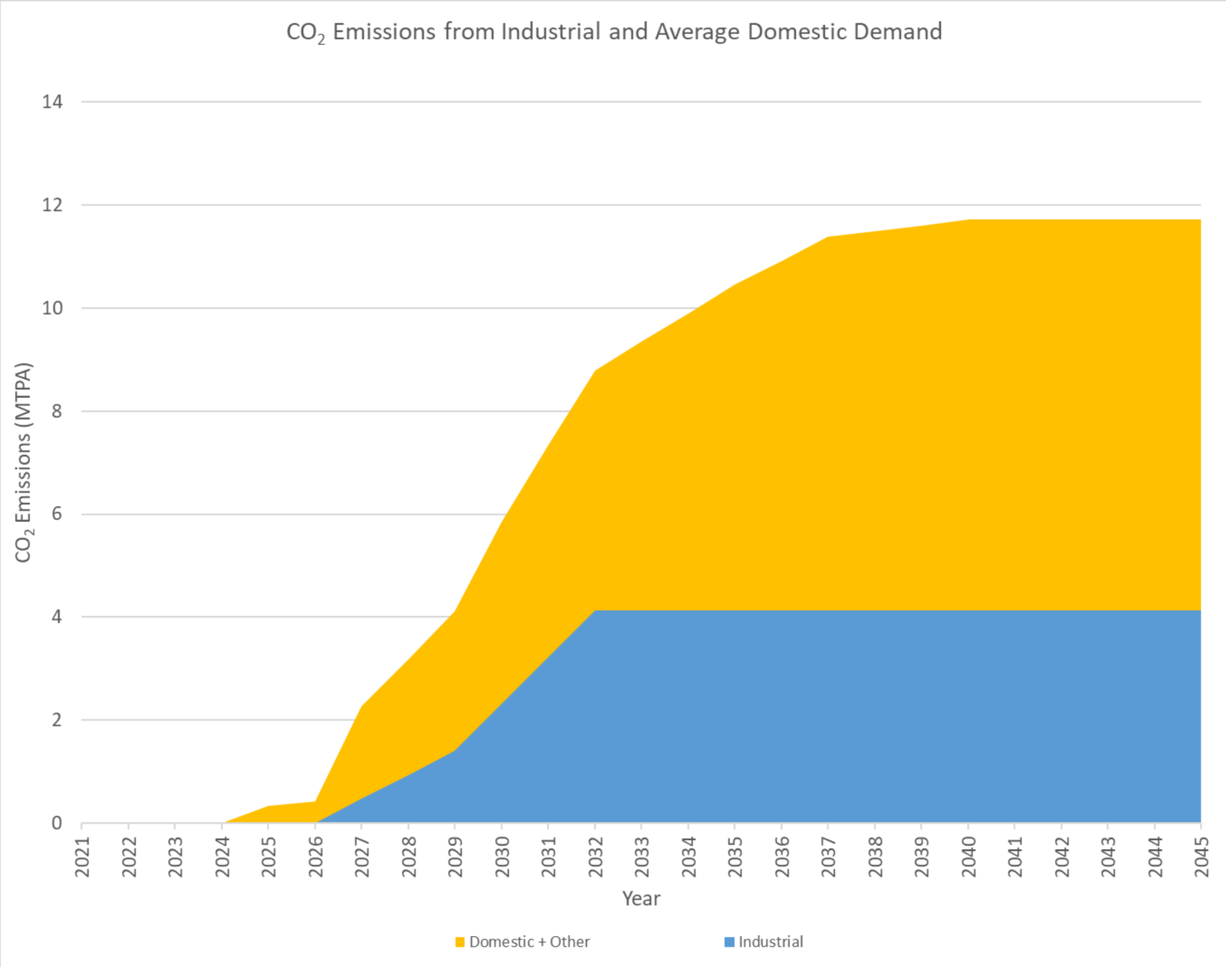

Figure 14 – Scenario 3: Industrial CO_2 Emissions from Industrial and Domestic Demand (all locations)

Figure 14 demonstrates the CO_2 emissions from the hydrogen demand calculated for industrial users and domestic users. This figure shows that industrial demand starts two years after domestic with industrial emissions reaching around 4 MTPA in 2032 and domestic and industrial combined emissions reaching almost 12 MTPA after 2040.

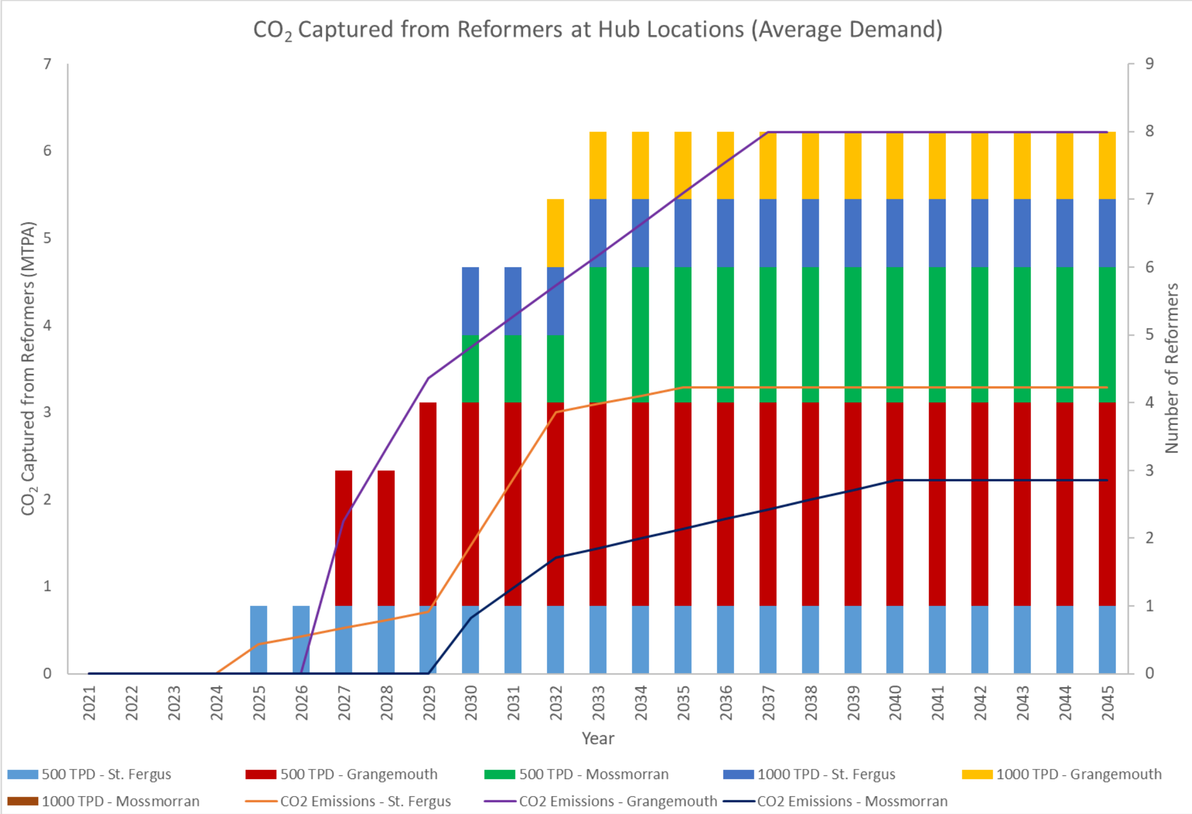

Figure 15 - Scenario 3: Average CO_2 Captured from Reformers by Location

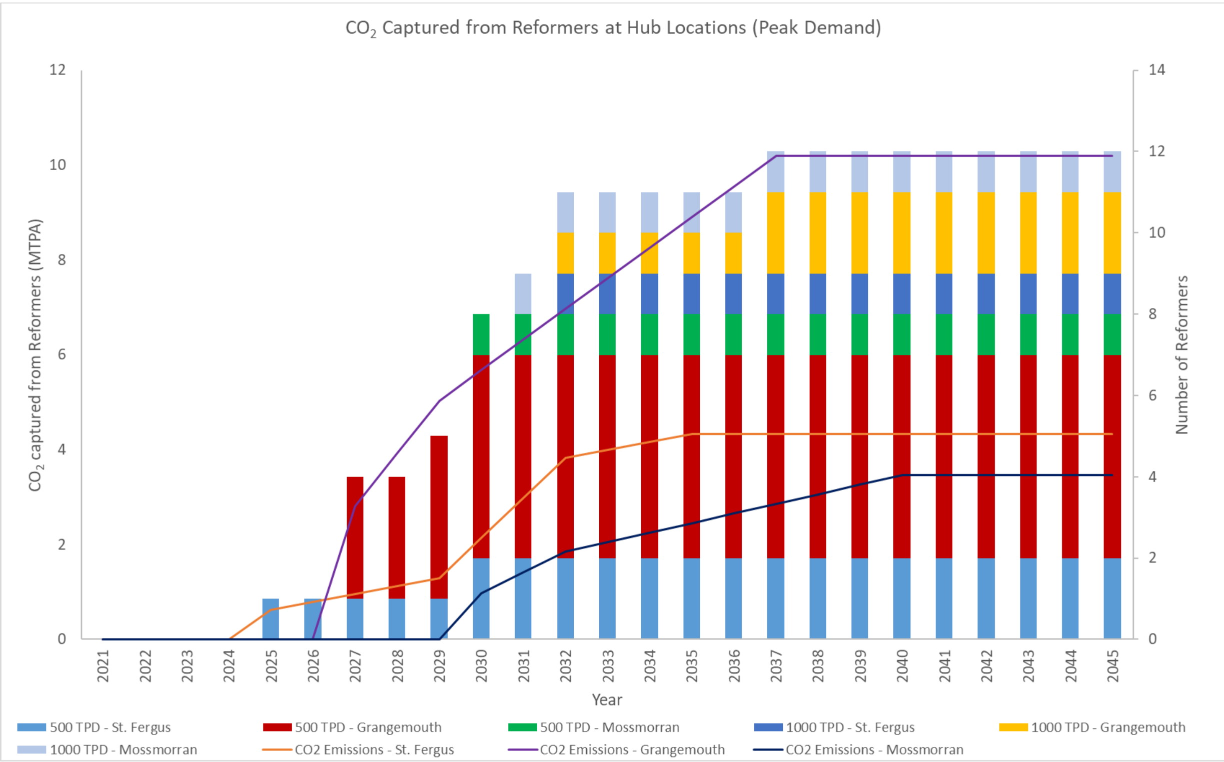

Figure 16 - Scenario 3: Peak CO_2 Captured from Reformers by Location

Figure 15 and Figure 16 show the CO_2 captured from the new blue hydrogen production facilities required for industrial and domestic demand broken down by location for both average and peak hydrogen demand respectively.

Table 9 provides the number of reformers for each location for average and peak demand. As expected, the highest average and peak CO_2 rates are generated at Grangemouth. This is because the largest hydrogen customer base is within the Grangemouth region. Looking at just the average CO_2 rates, Grangemouth captures 6.2 MTPA CO_2 by 2045 followed by St. Fergus and then Mossmorran at 3.3 MTPA and 2.2 MTPA respectively.

As noted in Section 5.4, peak values are provided in this report for the case where the maximum rate of hydrogen use is covered by installed capacity, with limited availability of storage facilities. The authors expect this is less likely than the long-term provision of storage facilities, but hydrogen storage is outside the scope of this study.

Table 9 - Number of Reformers for Average and Peak Demand

Location	Reformer Size (TPD)	Number of Reformers	
		Average	Peak
St. Fergus	500	1	2
	1000	1	1
Grangemouth	500	3	5
	1000	1	2
Mossmorran	500	2	1
	1000	0	1

8 Scenario 4: National Hydrogen

8.1 Hydrogen Demand Profile

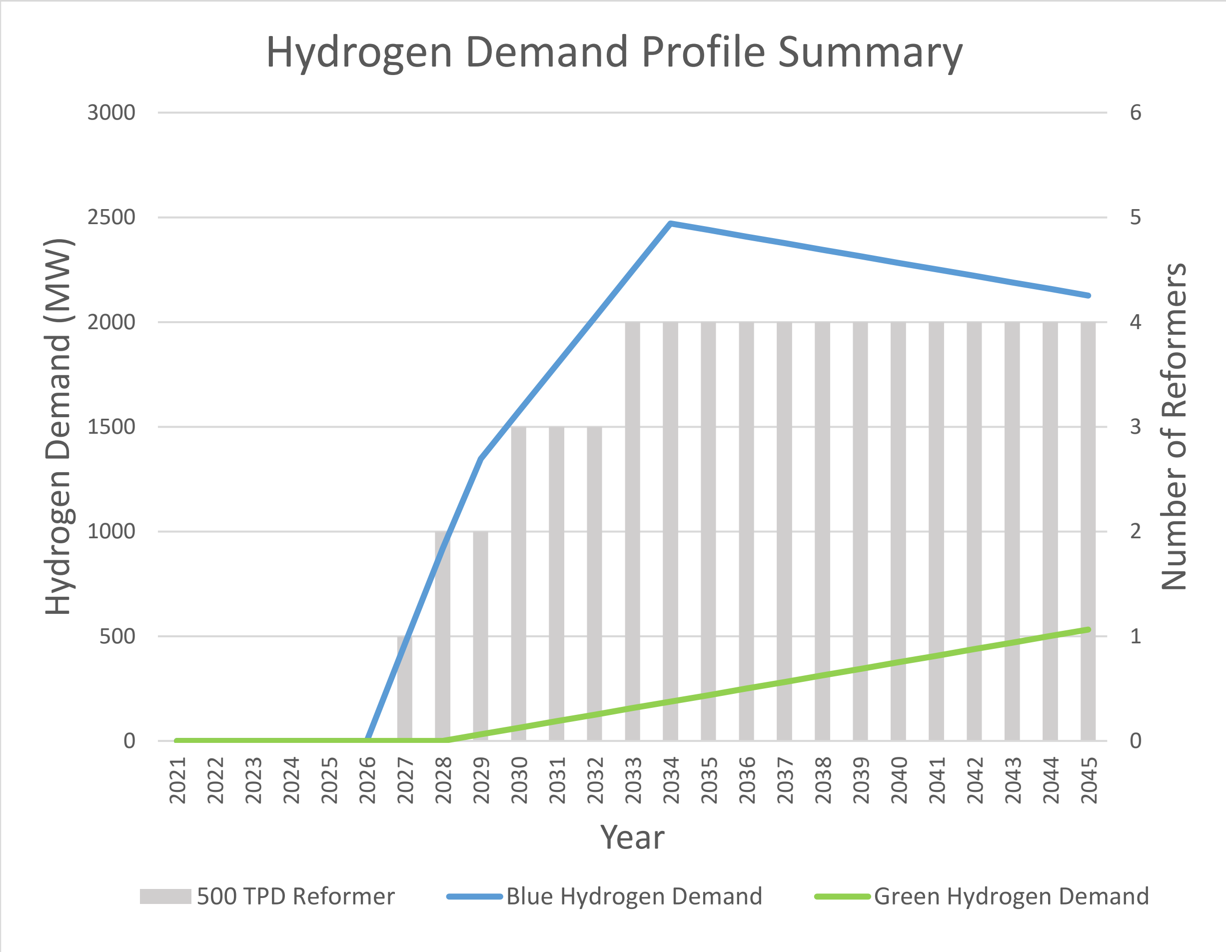

Figure 17 - Hydrogen Demand Profile for Scenario 4

Figure 17 illustrates the breakdown of hydrogen demand for Scenario 4 in terms of blue and green hydrogen. The chart also indicates the number of 500 TPD reformers that are required to meet the blue hydrogen demand. Table 10 highlights the key events for the Scenario 4 timeline. When compared with Figure 10, it is clear that hydrogen demand profiles for blue and green hydrogen are very similar to Scenario 3. As before, blue hydrogen production starts at Grangemouth in 2027 followed by blue hydrogen production at St. Fergus in 2030. However, in this scenario, Mossmorran is not a hydrogen production hub, and so the peak blue hydrogen demand is met by 2034 at a value of 2471 MW. Similar to Scenario 1 and 3, blue hydrogen production starts in 2025 through the Acorn Hydrogen Project for commercial and domestic users which is not taken into account in Figure 17. From 2029, green hydrogen production starts at the Aberdeen hydrogen hub which gradually replaces the blue hydrogen demand – the total green hydrogen demand by 2045 is 485 MW.

Similar to Scenario 3, an assumption has been made for green hydrogen demand whereby 20% of the total blue hydrogen demand by 2045 would be replaced by green hydrogen demand – this was in addition to the existing industrial green hydrogen demand dictated by the emitters.

Table 10 - Key Events for Scenario 4

Event	Year
Blue hydrogen production starts as St. Fergus through the Acorn H2 project.	2025
Blue hydrogen production starts at Grangemouth	2027
Green hydrogen production starts at Aberdeen Hub (Dolphyn Project)	2029
Blue hydrogen production starts at St. Fergus for industrial users	2030

8.2 Cost of Blue Hydrogen

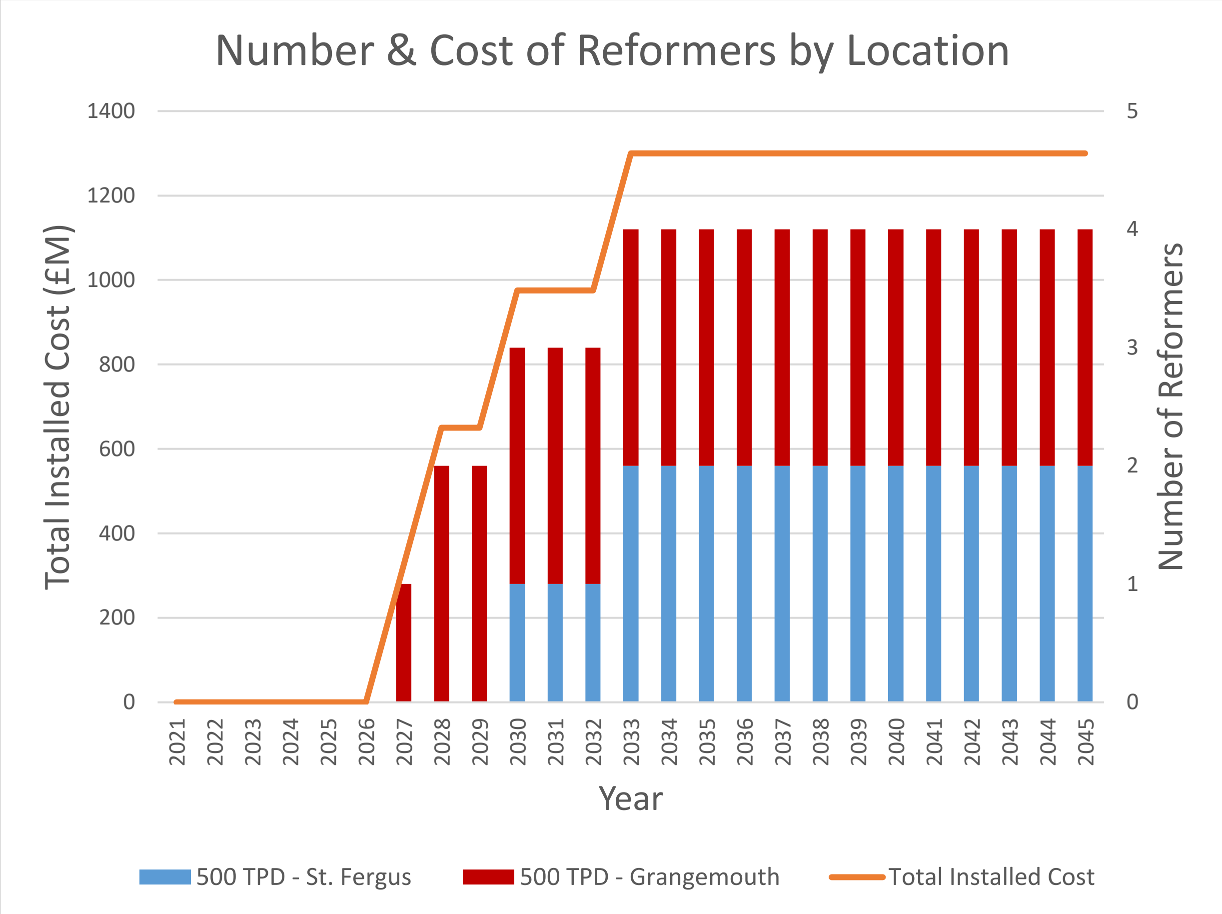

Figure 18 - Scenario 4: Total Installed Cost for Blue Hydrogen

Figure 18 illustrates the TIC for the blue hydrogen production facilities with time for Scenario 4 and Figure 19 indicates the share of TIC by location. As can be seen from the chart, two 500 TPD reformers are required at St. Fergus – one in 2030 and the other in 2033 with a TIC of £650M. In addition, two 500 TPD reformer are required at Grangemouth – one in 2027 and the other in 2028 with a TIC of £650M. Therefore, overall, a TIC of £1,300M is predicted for the blue hydrogen production facilities by 2045.

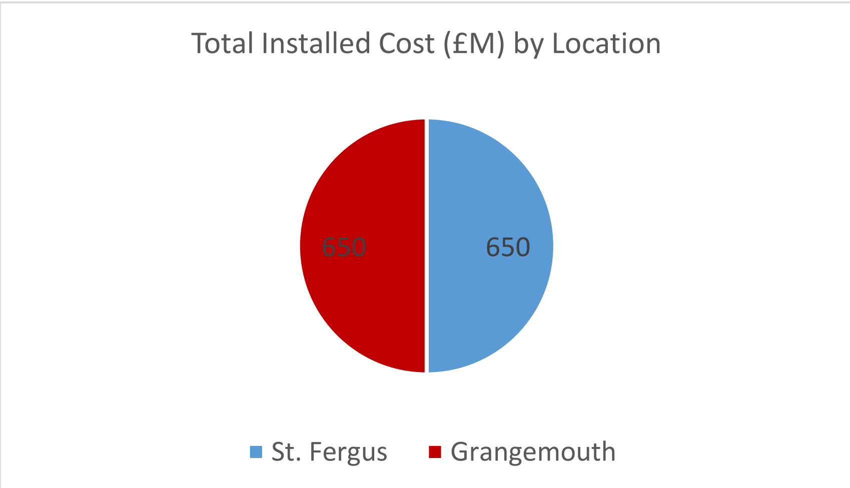

Figure 19 - Scenario 4: Breakdown of Cost by Location

8.3 Cost of Green Hydrogen

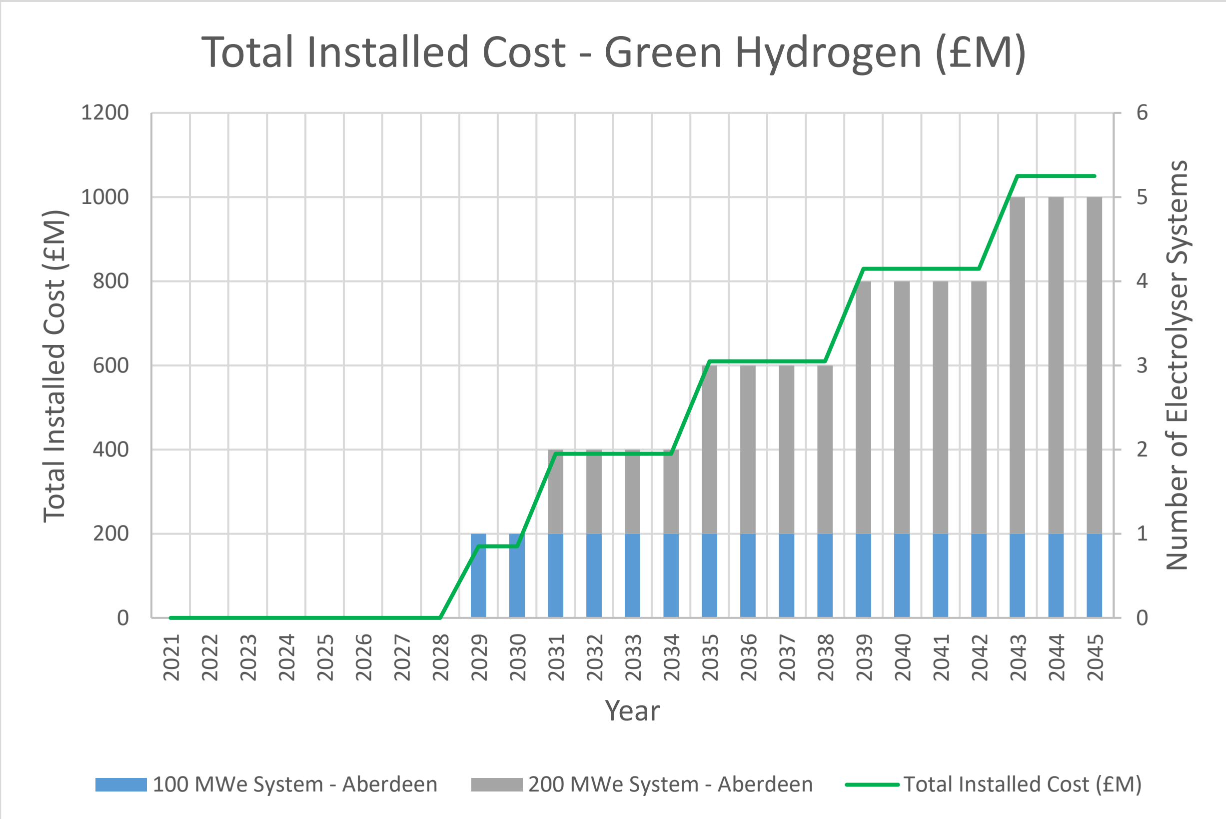

Figure 20 - Scenario 4: Total Installed Cost for Green Hydrogen

Figure 20 illustrates the TIC for green hydrogen production for Scenario 4. For this scenario, green hydrogen is produced from a single hub located in Aberdeen. An initial 100 MWe system is required in 2029 with a TIC of £170M. As can be seen, the number of electrolyser systems gradually increases from 2029 through to 2045 with an additional four 200 MWe systems being required to meet the green hydrogen demand by 2045. Therefore, overall, the TIC for green hydrogen production is estimated to be £1,050M by 2045.

8.4 CO_2 Captured from New Blue Hydrogen Facilities

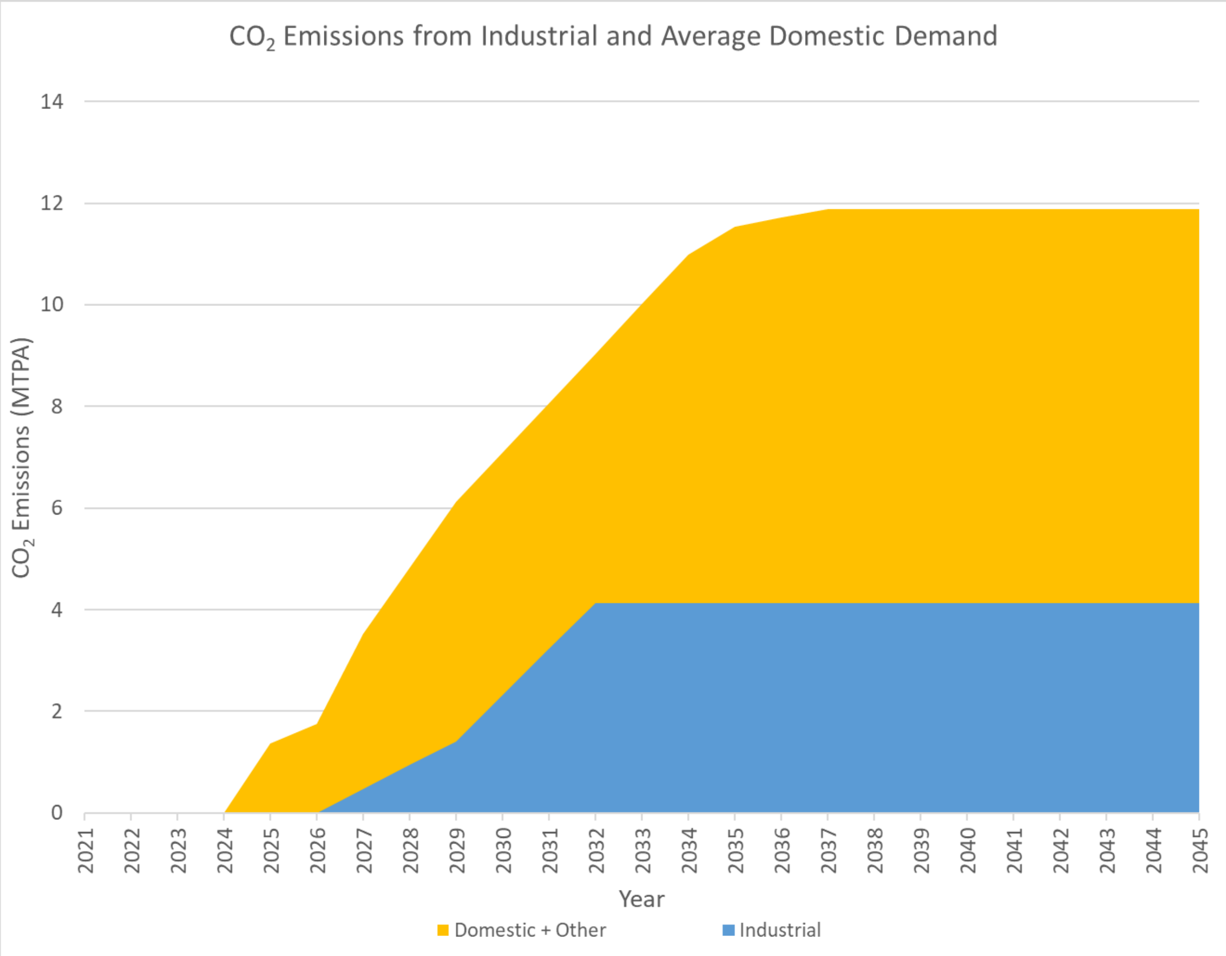

Figure 21 – Scenario 4: Industrial CO_2 Emissions from Industrial and Domestic Demand (all locations)

Figure 21 shows that industrial demand starts two years after domestic, same as for scenario 3, with industrial emissions also reaching around 4 MTPA in 2032. Domestic and industrial combined emissions reach almost 12 MTPA after 2036.

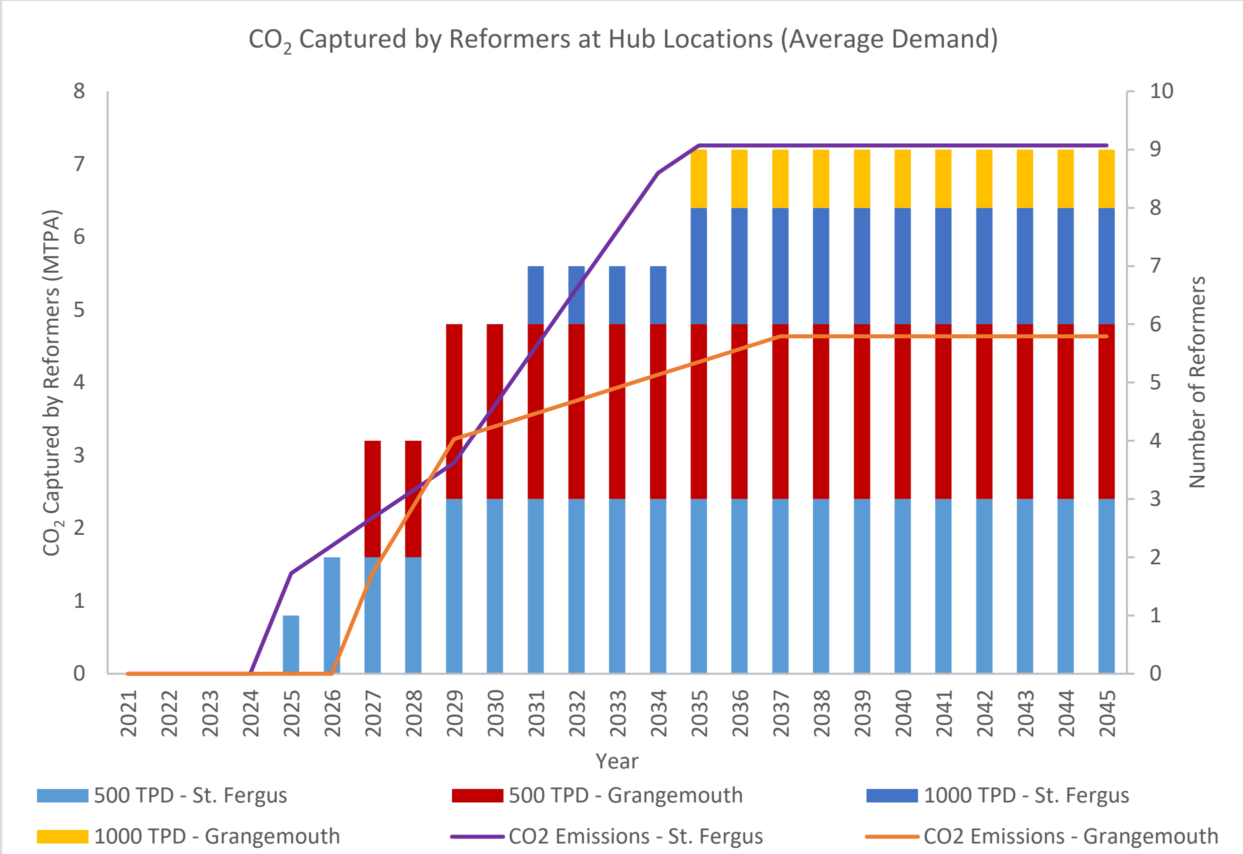

Figure 22 - Scenario 4: Average CO_2 Captured from Reformers by Location

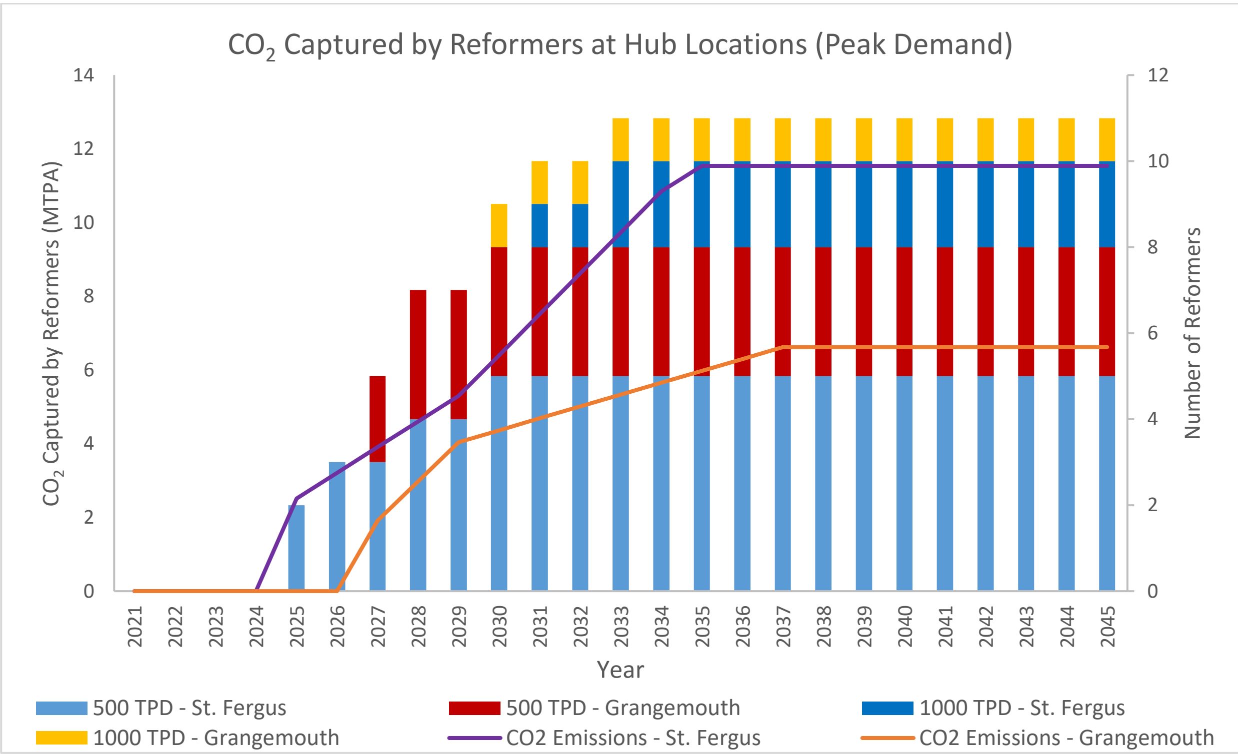

Figure 23 - Scenario 4: Peak CO_2 Captured from Reformers by Location

Figure 22 and Figure 23 show the CO_2 captured from the new blue hydrogen production facilities required for industrial and domestic demand broken down by location for both average and peak hydrogen demand respectively.

Table 11 provides the number of reformers for each location for average and peak demand. As expected, the highest CO_2 rates are generated at St. Fergus as it serves as the main hydrogen production centre for the scenario. Looking at just the average CO_2 emissions, St. Fergus captures the most emissions at 7.3 MTPA by 2045 followed by Grangemouth at 4.6 MTPA by 2045.

As noted in Section 5.4, peak values are provided in this report for the case where the maximum rate of hydrogen use is covered by installed capacity, with limited availability of storage facilities. The authors expect this is less likely than the long-term provision of storage facilities, but hydrogen storage is outside the scope of this study.

Table 11 - Number of Reformers for Average and Peak Demand

Location	Reformer Size (TPD)	Number of Reformers	
		Average	Peak
St. Fergus	500	3	5
	1000	2	2
Grangemouth	500	3	3
	1000	1	1

9 Scenario 5: Renewables Push

9.1 Hydrogen Demand Profile

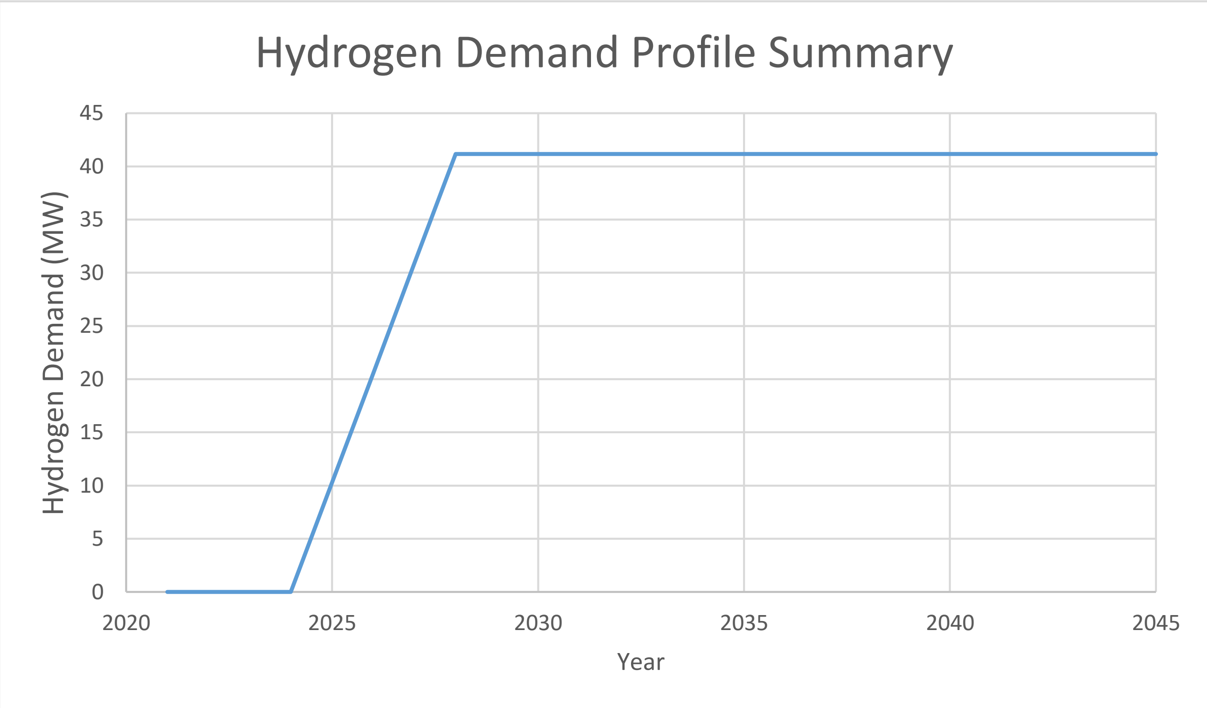

Figure 24 - Hydrogen Demand Profile for Scenario 5

Figure 24 illustrates the hydrogen demand profile for Scenario 5 and Table 12 highlights the key events for Scenario 5. The profile indicates green hydrogen production at the Aberdeen and Fife production sites, both beginning production in 2025. The total hydrogen demand of 41 MW is met by 2029.

Table 12 - Key Events for Scenario 5

Event	Year
Green hydrogen production to Arjo Wiggins from offshore wind supplied through the Dolphyn project (15km offshore Aberdeen)	2025
Green hydrogen production to supply Diageo (Fife)	2025

9.2 Cost of Green Hydrogen

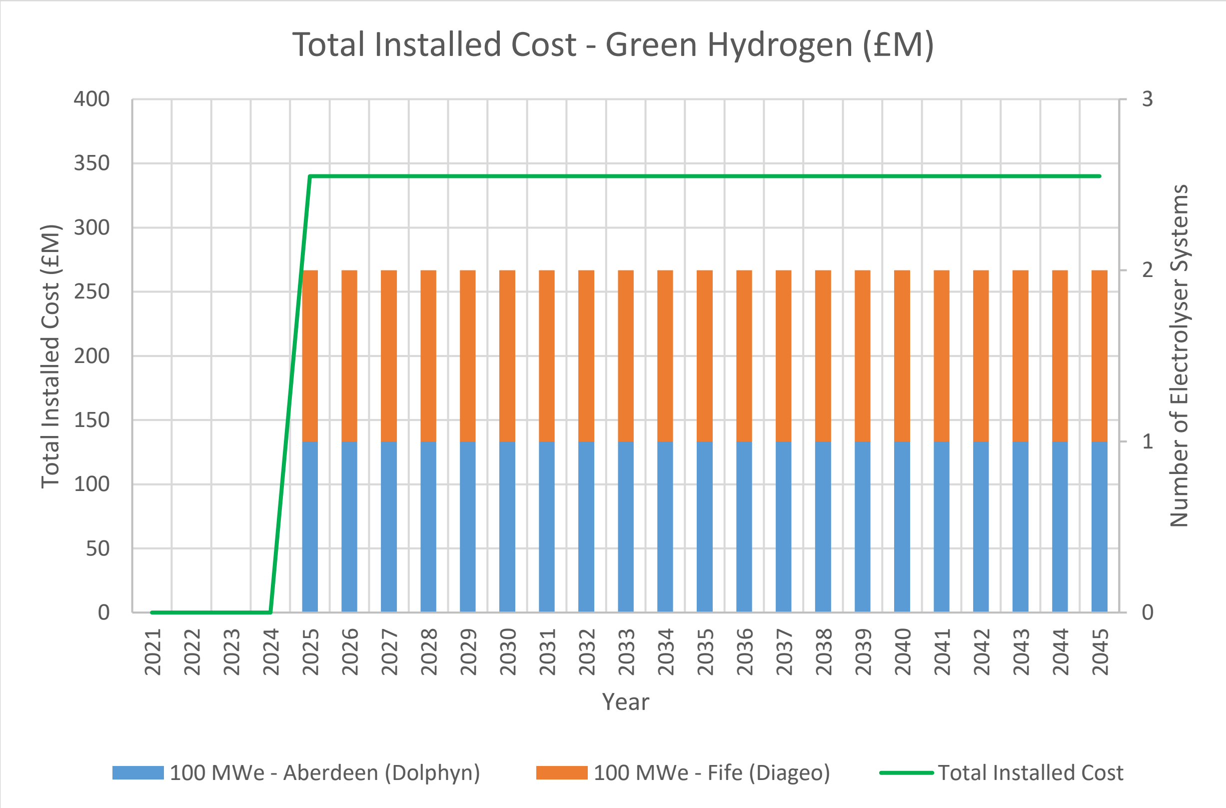

Figure 25 - Scenario 5: Total Installed Cost for Green Hydrogen

Figure 25 illustrates the TIC for green hydrogen production for Scenario 5. Two 100 MWe electrolyser systems are required to meet the hydrogen demand for this scenario: one in Aberdeen and the other in Fife. Both production hubs come online in 2025. The TIC for green hydrogen production for this scenario is therefore estimated to be £340M.

10 Scenario 6: CO_2 Shipping

10.1 Hydrogen Demand Profile

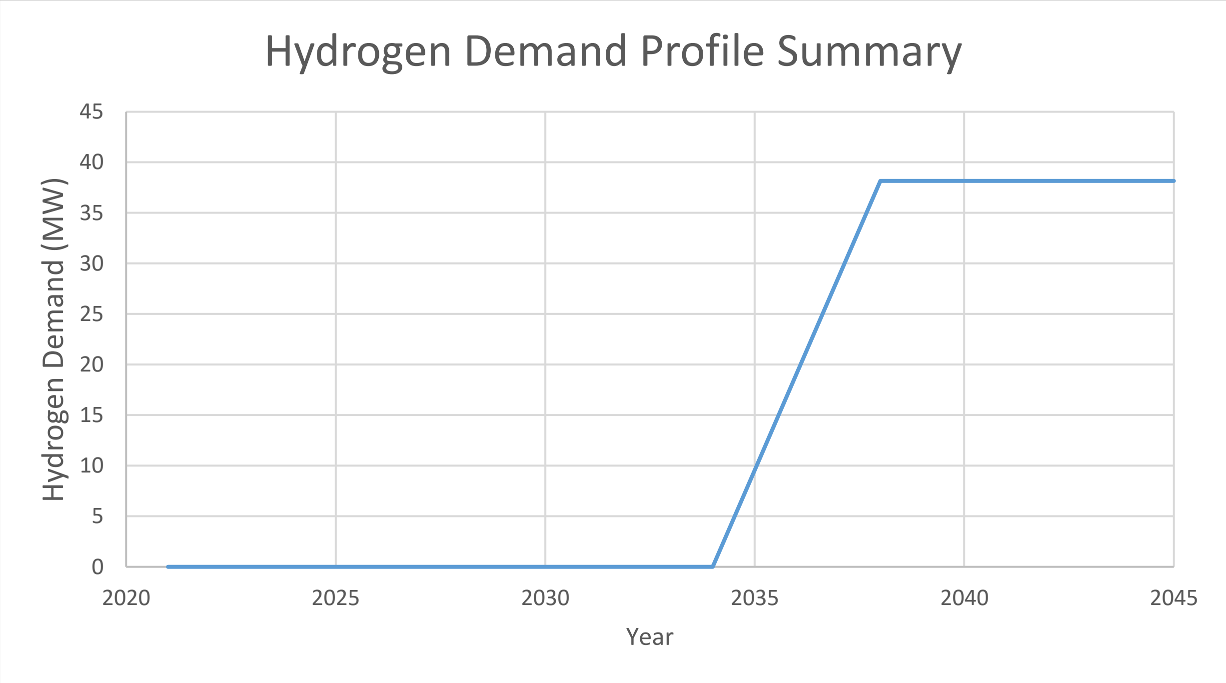

Figure 26 - Hydrogen Demand Profile for Scenario 6

Figure 26 illustrates the hydrogen demand profile for Scenario 6 and Table 13 highlights the key events for the scenario. The profile indicates the green hydrogen production at the Aberdeen production site from 2025. The total hydrogen demand of 38 MW is met by 2029.

Table 13 - Key Events for Scenario 6

Event	Year
Green hydrogen production to Arjo Wiggins from offshore wind supplied through the Dolphyn project (15km offshore Aberdeen)	2025

10.2 Cost of Green Hydrogen

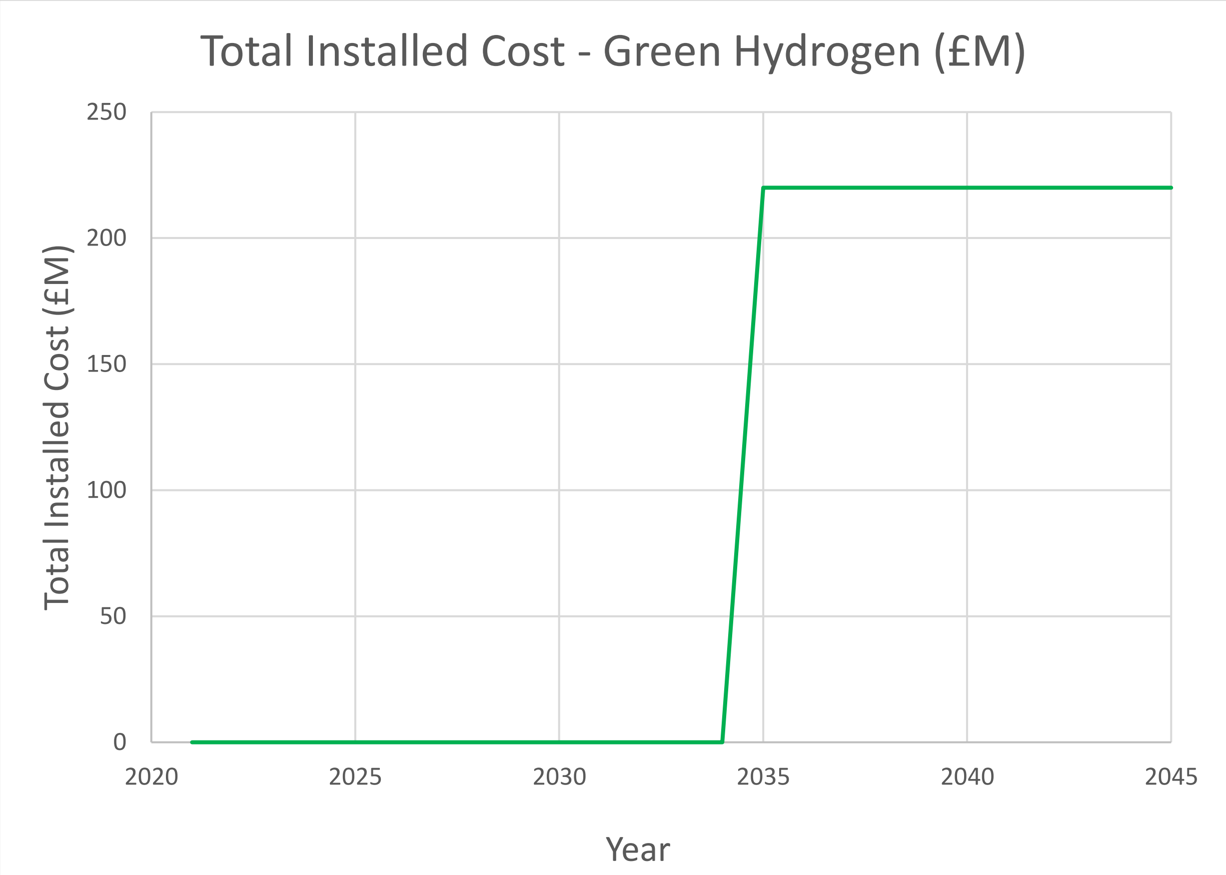

Figure 27 - Scenario 6: Total Installed Cost for Green Hydrogen

Figure 27 illustrates the TIC for green hydrogen production for Scenario 6. It shows that a single 200 MWe electrolyser system is required to meet the green hydrogen demand for the scenario, equating to £220M.

11 Financial Comparison between Scenarios

Table 14 – TIC for Blue and Green Hydrogen Facilities by Scenario

	Total Installed Cost (£M)		
Scenarios	BLUE	GREEN	TOTAL
Scenario 1	£975M	£220M	£1,195M
Scenario 2	-	-	-
Scenario 3	£1,300M	£1,220M	£2,520M
Scenario 4	£1,300M	£1,050M	£2,350M
Scenario 5	-	£340M	£340M
Scenario 6	-	£220M	£220M

Table 14 shows the breakdown of TIC for blue and green hydrogen production facilities for each of the scenarios. Note that Scenario 2 has no new blue or green hydrogen production associated with it and hence the TIC for blue and green hydrogen production is zero. Scenarios 5 and 6 have the lowest TICs of £340M and £220M respectively – this was expected due to having the lowest hydrogen demands. Scenario 1 has a combined TIC of £1,195M for the blue and green hydrogen facilities. Scenarios 3 and 4 have the highest TICs of £2,520M and £2,350M respectively, for the blue and green hydrogen facilities.

The deployment costs above must not be considered in isolation or directly compared to one another. The hydrogen production cost is only one element in each scenario. It is necessary to look at the overall development costs indicated in the Work Package 5 results to gain insight into the true costs for each scenario.

Scotland’s Net Zero Roadmap