Wales & West Utilities

Regional Decarbonisation Pathways

September 2022

DOCUMENT CONTROL

ESC programme name	Wales and West Utilities – Regional Decarbonisation Pathways
ESC project number	ESC00539
Version*	1.4
Status	Final Report
Restrictions*	Confidential
Release date	01/09/2022
External release ID	

* Refer to the Information Classification Policy

Review and approval (ESC)

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Combined Report Revision History

Date	Version	Comments
01.09.2022	1.4	Final Report – Issued Final dated 01 Sep
18.07.2022	1.3	Final Report – Minor Amendments (Fig. 12)
15.06.2022	1.1	Final Report – Minor Amendments
10.06.2022	1.0	Final Report
13.05.2022	0.1	Draft for Combined Report for approval

ESC Revision History

Date	Version	Comments
01.04.2022	0.3	Draft for approval

Costain Revision History

Date	Version	Comments
10.05.2022	R3	Incorporation into Combined Report

CONTENTS

SECTION A: EXECUTIVE SUMMARY

1. EXECUTIVE SUMMARY: CONTEXT

Wales & West Utilities (WWU) have been taking initial steps to identify the likely decarbonisation options for their area of operations, with particular focus on the likely future extent and operations of the gas distribution network. However, significant uncertainty remains around the mix of end-user technologies and decarbonised form of energy supply which will be implemented to reach Net Zero energy system operations. Irrespective of the solutions which are ultimately implemented by end-users, it is anticipated that WWU will need to undertake a major programme of change to support them.

In terms of the developed approach for decarbonisation of the UK's gas networks, work has already been undertaken by the Energy Networks Association (ENA), including the 'Pathway to Net Zero' and the ongoing 'Gas Goes Green' to establish credible transition pathways for UK gas networks at a national level. However, limited work has been undertaken to understand how these high-level Net Zero pathways might effectively translate to regional and sub-regional networks for planning and implementation of the transition.

The purpose of this project is to address this analytical gap and progress present thinking to the next level, developing an analysis of how WWU and its partners might decarbonise the gas networks in Wales and the South-West of England, consistent with the wider UK decarbonisation picture. The project has comprised two parts. Part 1 is product of strategic whole system plan consistent with Net Zero targets led by Energy Systems Catapult and Part 2 is a conceptual plan for implementation led by Costain.

The Strategic Plan consists of whole system modelling of Wales and the South-West of England; an assessment of the network implications; and a further assessment of the implications for individual sub-regions. The Conceptual Plan illustrates the anticipated gas network end state and describes a potentially feasible transition pathway to achieve it.

The analysis is based on three credible energy system pathway scenarios to 2050 for Wales and the South-West of England, to meet both the UK's carbon budgets and, ultimately, Net Zero commitments. The scenarios tested different levels of hydrogen demand across the network – the implications of these scenarios for the WWU gas network were analysed at a regional and sub-regional level, as shown in Figure 1.

Figure 1: The Wales and West Utilities region analysed in this project (Source: Wales & West Utilities)

The document is set out in 4 sections. **Section A** provides an Executive Summary of both the Strategic Plan work undertaken by the ESC and the Conceptual Plan work undertaken by Costain. It also provides a high-level summary of the methodological approach used to deliver the analysis. **Section B** presents ESC's detailed whole system modelling analysis underpinning the Strategic Plan. **Section C** presents Costain's detailed engineering analysis that underpins the Conceptual Plan. **Section D** presents ESC's Strategic Plan analysis and Costain's Conceptual Plan analysis for each of the sub-regions.

2. EXECUTIVE SUMMARY: STRATEGIC PLAN

Across the WWU licence area, hydrogen and natural gas have changing roles through the transition to a Net Zero energy system. This project created three future scenarios in collaboration with WWU to assess a range of futures for the energy system in Wales and the South-West of England and to consider potential gas network implications for sub-regions within them.

As one of the major unknowns and key drivers of the future gas grid, different heating assumptions were tested, with scenarios involving a more significant role for hydrogen in home heating and a more limited role for electric heat pumps and district heat networks (DHN). These scenarios represent a future where limited policy support and consumer acceptance and uptake of electrical heating, increases the viability of hydrogen boilers and hybrid heating solutions.

The three scenarios developed and discussed in this report are a high electrification scenario, similar to previous ESC analysis; a high hydrogen scenario; and a scenario which takes a balanced view lying midway between the other two. All three scenarios meet the current UK Carbon Budgets and the 2050 Net Zero target.

Unabated natural gas use largely removed by 2050

In all three scenarios, unabated natural gas is largely removed from demand in Wales and the South-West of England by 2050, with a continued limited role in industry, both unabated and in combination with carbon capture and storage (CCS). There is a significant role for natural gas in blue hydrogen production. Hydrogen is primarily used to meet industrial and heating (commercial and residential) demands in 2050 – sub-regional differences in adoption of hydrogen solutions arise, driven by differences in population densities, geography and existing energy infrastructure characteristics.

The number of retained non-industrial (primarily residential) gas connections are reasonably consistent across most of the WWU network in all three scenarios, but with some variation across the different sub-regions. This variation is driven mainly by disconnections related to the growth of district heating in and around urban centres, such as Bristol, Cardiff and Swansea. In these locations, higher heat density delivers lower cost of district heat networks, and prompts a switch away from gas boilers and a related reduction in domestic gas network connections.

Hydrogen has an important role in energy system designs that cost-effectively meet carbon budgets and Net Zero goals for the region

The development of hydrogen networks is shown to offer system value, particularly in meeting peak heating demand and in industry. However, the transition of a natural gas distribution network to one transporting hydrogen is recognised as a complex technical, social, regulatory, and logistical challenge. Analysis of the WWU network at a strategic level, inclusive of a working hypothesis that piped supplies of both hydrogen and natural gas are required at the point of transition, have found that this practical constraint could require a significant amount of new network assets on the intermediate and high (Local Transmission System - LTS) pressure tiers. This will require a high level of investment and careful consideration of the appropriate regulatory model. The selection of this regulatory model has the potential to further impact the demand and the shape of the future network, introducing a requirement for further iterations considering these factors.

The adoption of hybrid heating systems offers significant value to the energy system

The relatively small difference in the number of disconnections across the three scenarios can be explained by the widespread substitution of gas boilers with hybrid heating systems, which combine a hydrogen boiler and heat pump. In general, these use hydrogen to meet peak demand and a heat pump to meet baseload demand. The system value of hybrid heating systems, in part, derives from the avoided electricity network reinforcement costs that this hydrogen peaking allows. As well as optimising the level of electricity network investment required to meet peak heating demands, hybrid heating systems also have the potential to retain a certain level of resilience in the energy system.

Hybrid heating systems are subject to uncertainty

There is, however, uncertainty around the deployment of hybrid heating systems. This will be driven, in part, by government policy, consumer preferences, supply chain development, and where domestic and commercial gas grid connections are retained. The extent of hybrid deployment seen in the high electrification scenario may not persist if this wider optimisation is carried out. It also does not consider the attractiveness of these heating solutions for consumers, the level of disruption and the ability of supply chains to deliver. Further research would be required to quantify these factors and to provide more clarity on the efficacy of the approach.

Hybrid heating system adoption needs to be understood to plan how gas network evolves and operation changes

Hybrid heating system installation in these scenarios is a key driver in the evolution and operation of the gas and hydrogen networks from now to 2050. A high number of hybrid heating systems requires a hydrogen network of a very similar scale, in terms of length and number of connections, to the natural gas network in operation today. However, the operating profile of hybrid heating systems, where electricity supplies much of the base load, influences the volume of hydrogen transported through the gas network. This highlights the interdependency of future home heating choices by consumers, and gas network infrastructure planning, design, operation and supporting regulatory mechanisms.

This also highlights a need for further investigation and understanding of local energy system design and the effective operations of such systems. Specifically, with capability to optimise energy system investment options, with interdependencies between different levels of geography, across vectors and along value chains.

Hydrogen use in industry displaces much of today's fossil fuel use by 2050

In industry, all three scenarios see hydrogen displacing liquid fossil fuels currently used to meet energy demand. Hydrogen also displaces natural gas use, but to a lesser degree. Natural gas, unabated and in combination with CCS, is used in industry to meet energy demand throughout the entire pathway in all three scenarios. From the 2030s, natural gas use is combined with CCS in order to eliminate emissions from industry. Network planning will need to consider this ongoing demand and how a retained gas network and supply could continue providing it economically alongside the infrastructure required to support hydrogen demand.

The modelling approach adopted in the development of the strategic plans is devised to include full coverage of the whole energy system, but also provide sufficient granularity regarding energy infrastructure. However, it remains important to understand the approach's limitations. This includes the approach taken to heating technology allocation.

Wider energy system uncertainties have the potential to change the pathways to 2050

It should be noted that this modelling was undertaken prior to the recent geopolitical events in Ukraine and changes in natural gas market prices. The whole system techno-economic modelling will be sensitive to a sustained increase in natural gas prices and government security of supply strategy may also create other constraints. Further work will be required to understand the full impact of a sustained rise in natural gas prices on the economics and cost effectiveness of hydrogen consumption and the balance between blue and green hydrogen production to meet it. Preliminary modelling carried out by ESC suggests that the result would be a switch from blue to green hydrogen production.

Future whole energy system scenarios consistent with Net Zero ambitions can be translated into local gas network infrastructure designs

The sub-regional planning approach adopted in this work is applicable across the UK for strategic planning of gas network transition to hydrogen networks. This has a role that sits above network modelling and network strategic optioneering that could be developed to take into account further technical, economic and social elements.

3. EXECUTIVE SUMMARY: CONCEPTUAL PLAN

The Conceptual Plan augments the whole system modelling outputs derived from the Strategic Plan, with an engineering and technical perspective to develop a gas network plan and assess the potential locations within the region for hydrogen production and likely demand forecasts. The scope includes evaluation of the capacity of the WWU infrastructure required to deliver the volumes of hydrogen to the main demand centres, and development of conceptual network maps for the Local Transmission System (LTS) network for each of the sub-regions at 5-yearly intervals through to production of a perspective of the network in 2050.

Repurposing the Gas Grid is Essential to Delivering Net Zero

To deliver net zero, we need to fully decarbonise the UK's existing energy systems – addressing present day petroleum (40%) as well as electricity (18%) and gas (34%) demand. (BEIS Figures for 2019). Even with the potential for demand reduction due to energy efficiency, demand side management and transition to alternative supply arrangements, in practice it will be difficult to realise the transition to net zero without developing both low carbon electricity and gas networks. Based upon the modelling undertaken in this study, a role is envisaged for a low carbon gas network, even in a High Electrification scenario, which would involve retention and repurposing of the vast majority of the existing network infrastructure to realise hybrid heating systems. Any uncertainty is therefore more over the extent and utilisation factor for a future hydrogen gas network, than whether it is required.

Initial Projects will be Industry Focused

Reflecting the present UK and Welsh Government's policy and funding approach, initial decarbonisation initiatives will be led by industry: South Wales is one of the six regions designated by the UK Government under the Industrial Cluster's Mission. The projects implemented to address emissions in the industrial clusters will provide foundational decarbonisation infrastructure which will then provide a basis for the energy transition solutions applied to decarbonise the remaining industrial and also domestic emissions within these regions, as well as the build-out solutions which will be applied to decarbonise the neighbouring regions.

South Wales Presents a Strategic Location for the Initial Implementation of Net Zero in the UK

The LNG import terminals in South Wales and associated pipeline transportation system connecting to the rest of the UK offers a strategic location for initial production of blue hydrogen at scale, and the ability to use LNG as a feedstock to provide an effective hydrogen 'storage' capability. The existing gas import and transport infrastructure also provides the potential to then transition smoothly to green hydrogen importation and indigenous production at scale: providing greater energy security of supply than with present LNG importation operations.

Wales is Likely to be a Net Exporter of Hydrogen

Wales, especially South Wales is presently a net energy producer, with capability to export both electricity and gas to the rest of the UK. The region has the potential to continue to do so in a future UK net zero energy system – whether through decarbonisation of existing energy production facilities such as the existing LNG terminals and/or CCGT power stations, and/or the introduction of new green energy importation and/or production. Therefore, the region has the potential to export hydrogen to the rest of the UK: across the rest of WWU's supply area to the South West and also to the Midlands.

North Wales is anticipated to initially import hydrogen from the production facilities developed in the North West by the HyNet programme. In the longer term the region has the potential to become a net exporter of hydrogen, e.g. from offshore wind or potentially from nuclear cogen hydrogen production facilities

An Energy System (Including A Gas Network) Transition Sequencing Programme Is Needed

No energy transition sequencing philosophy presently exists for the UK and not all regions will necessarily transition to net zero over the same timescales: If there are areas which will be net producers of hydrogen (e.g. South Wales & the North West), then they arguably will need to decarbonise first so that ahead of other areas (e.g. North Wales & the South West) which can then be transitioned to net zero afterwards. This would mean Net Zero in South Wales needs to be achieved earlier than 2050 – possibly by 2040 or even sooner.

An energy transition sequencing philosophy for the whole of the UK is urgently required to confirm whether strategic regional decarbonisation, such as in South Wales, needs prioritisation.

Parallel Natural Gas and Hydrogen Networks Will Be Needed In South Wales

To manage the transition to a future 100% hydrogen network while maintaining security of supply, natural gas importation operations at Milford Haven will need to continue during the energy transition period to provide security of supply to gas consumers in parallel with establishment of a 100% hydrogen grid network.

If due to the sequencing of transition, it is identified that there is a need to prioritise hydrogen production in South Wales to deliver net zero across the UK by 2050, then this could necessitate having a 100% hydrogen pipeline operational in South Wales by the late 2020s or early 2030s at the latest.

The UK Government Needs to Provide Long Term Project Development And Route To Market Certainty

The British Energy Security Strategy published in April 2022 echoes similar previous plans for major new CCUS and nuclear power infrastructure projects which have largely remained unrealised. In addition to the development of a transition sequencing programme, to deliver the individual projects within such a programme, and also the associated supply chain capability and skills required to deliver Net Zero by 2050, industry and academia need greater medium to long term policy and development funding programme certainty. Otherwise, the risk of key stakeholders failing to commit to provide the necessary capacity and skills will be significantly increased.

Repurposing Existing Gas Network Infrastructure

The majority of WWU's LTS system in Wales and the South West was constructed from pipe material strength grade of X52 (L360) and below. These pipe materials are considered more suitable to the transportation of hydrogen due to the low strength of the alloys, which imparts resistance to hydrogen embrittlement and to other brittle fracture mechanisms. Steels with high tensile strengths can see a greater loss in fracture toughness properties, potential leading to failure. Where pipelines have been constructed of higher strength grade materials then further work may be required to be undertaken prior to conversion to confirm their suitability for hydrogen service.

There are a number of sections of the LTS network in South Wales which are over fifty years old and may potentially reach the end of their useable life shortly. Where these pipelines are to be replaced as part of a planned programme, then subject to an agreed regulatory policy and approach. A low regrets options would be to recommend that they are replaced with pipelines suitably oversized with a pipe material grade which will be suitable for hydrogen service.

Retention of Domestic and Commercial (non-industrial) Customer Base

Across most areas, a high retention of the existing gas network domestic and commercial (non-industrial) customer base is anticipated, based upon the modelled scenarios. This is due to hybrid heating system installation in the modelled scenarios being a key driver in the evolution and operation of the gas and hydrogen networks. Although the volume of future demand is dependent upon whether selected decarbonisation solutions focus on hybrid or hydrogen boiler solutions. The gas network still retains a major role in meeting peak energy demand.

4. EXECUTIVE SUMMARY: APPROACH

As discussed above, this project has been delivered by the ESC (Strategic Plan) and Costain (Conceptual Plan). Its draws on the organisations' respective knowledge and experience in future energy scenario development and whole system modelling (ESC) and engineering and network design expertise (Costain).

This collaboration and collective expertise have been utilised to develop and deliver a Strategic Plan and a Conceptual Plan for the South-West of England and Wales regions, and sub-regions within those, out to 2050. ESC's modelling outputs from the Strategic Plan have been used by Costain as a basis for developing its Conceptual Plan.

The scenarios developed by ESC for WWU explore different pathways to deliver Net Zero and meet Carbon Budget 6, whilst maintaining security of supply and balancing supply and demand. To ensure visibility of each organisations work, a joint methodology was established. The overview of the methodology is set out in Figure 2.

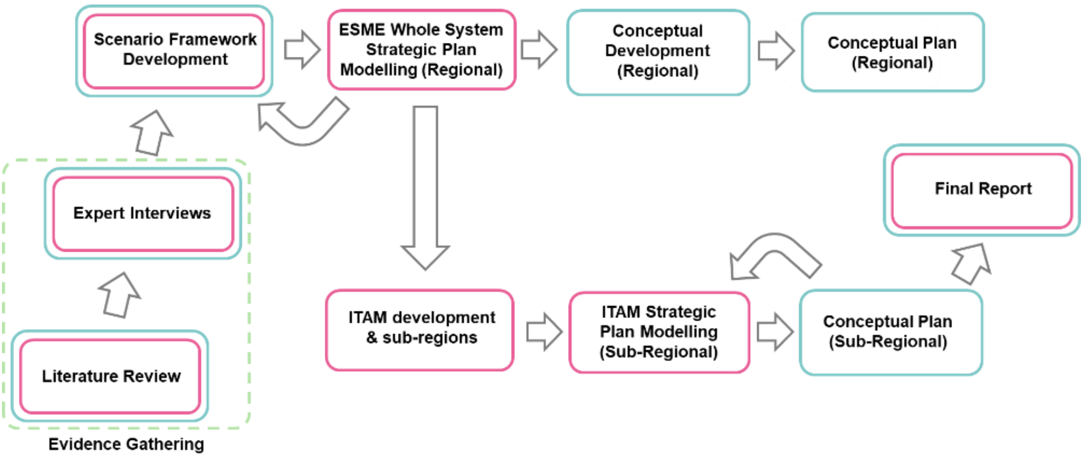

Figure 2: High level work breakdown structure for the project. ***Pink*** *activities are ESC,* ***Teal*** *activities are Costain.*

The key steps of the methodology are:

- **Evidence gathering:** This phase comprised of two activities: a literature review which sought to capture all the key issues to consider; and a series of interviews with key experts from different organisations, to further the literature review insights.
- **Scenario framework development:** ESC with support from Costain and in consultation with WWU developed a scenario framework to test and drive out the key insights against a range of hydrogen demand scenarios.
- **Whole system modelling:** ESC agreed key input assumptions with Costain and WWU for the ESME whole system modelling. ESME was used to model the three scenarios. Outputs were discussed with WWU and iterated to ensure sufficient separation between scenarios.
- **Regional Conceptual Plan:** Costain used the ESME outputs to assess what the energy system pathways from the three scenarios would mean for the gas transmission and distribution network transition from an engineering point of view.
- **ITAM development and sub-regions:** ESC discussed and agreed key input assumptions (e.g., hydrogen production sites) with WWU and Costain. ITAM was developed to allow the model to disaggregate the ESME results for the agreed sub-regions.

- **Sub-regional modelling:** ESC used the ESME whole energy system modelling outputs and disaggregated them for the agreed sub-regions using its ITAM model, to understand the 2050 implications for the different gas network pressure tiers.
- **Sub-regional conceptual plan:** Costain used the 2050 ITAM outputs to assess what the transition would mean for the gas networks in the WWU regions from an engineering perspective.

Scenario framework

Energy system modelling should not be seen as a means of predicting the future. Rather, it is a tool that can be used to aid decision making under uncertainty. There are clearly significant uncertainties in the future of the UK's energy system, but these are not just technical. The role of policy, consumer behaviour, societal trends and the economy also play a significant role.

The use of different scenarios is the way that this uncertainty has been investigated in this work. The analysis was carried out on three scenarios – high hydrogen, high electrification and balanced – based on a framework which allowed the variation of heating system preference on an electricity to hydrogen scale, as shown in Figure 3.

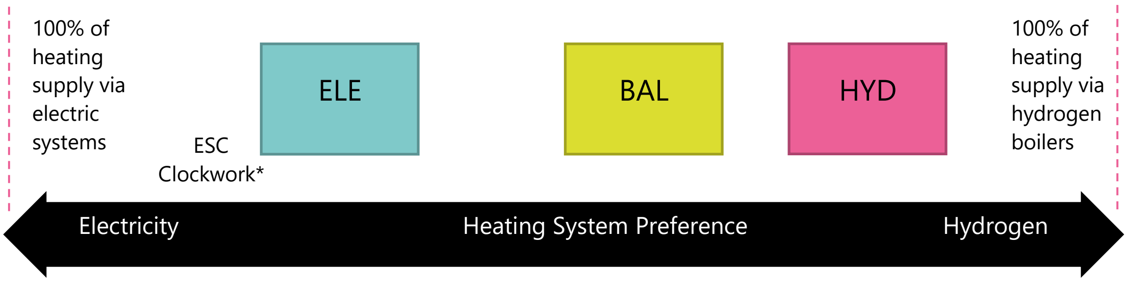

Figure 3: Scenario Framework ('ESC Clockwork' indicates where on this framework ESC's Clockwork scenario would be located ESC (2020). The Clockwork scenario represents a techno-optimistic view of how the UK's energy system may develop, with coordination from central Government driving long term investment in strategic energy infrastructure)*

Table 2 shows the scenario narratives, highlighting the technical, policy and consumer drivers for each. As can be seen, the scenarios primarily focus on the impact of different levels of low CO_2 heating systems. This was done as domestic heating demand is seen as the most significant factor influencing the future of the gas distribution network which WWU operates.

ELE	BAL	HYD
Policy support for air source heat pumps (ASHPs) is in place and propositions are developed which make the transition from natural gas boilers to ASHPs attractive to consumers. Like ESC's global assumptions.	Represents a mid-point between ELE and BAL in terms of ASHP deployment. Policy support is mixed, promoting different solutions in different areas and offering consumers viable choices.	The deployment of ASHPs is lower than anticipated due to constraints on the electricity distribution network, a lack of policy support from government and lack of consumer acceptance of the propositions from installers.

Table 1: Scenario narratives

The engineering analysis undertaken in delivering the conceptual plan scope takes account of various practical considerations for decarbonisation of the gas network around distribution of increasing volumes of hydrogen and reducing volumes of natural gas through to 2050. With the intention of providing a practical context to support further consideration of the outputs of the energy systems modelling work.

ABBREVIATIONS

ASHP	Air source heat pump
BAL	Balanced scenario
BoQ	Bill of quantities
BEIS	Department for Business Energy and Industrial Strategy
BF-BOS	Blast Furnace - Basic Oxygen Steelmaking
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilisation and Storage
CHP	Combined Heat and Power Plant
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COMAH	Control of Major Accident Hazards
COP	Coefficient of performance
CV	Calorific Value
DHN	District heat network
DRI	Direct Reduced Iron
EAF	Electric Arc Furnace
ELE	High Electrification scenario
ENA	Energy Networks Association
ESC	Energy Systems Catapult
ESME	Energy System Modelling Environment
ESO	Electricity System Operator
FCEV	Fuel Cell Electric Vehicle
FES	Future Energy Scenarios
GB	Great Britain
GDN	Gas Distribution Network
GHG	Greenhouse gas
GIS	Geographic Information System
GSHP	Ground source heat pump

GTYS	Gas Ten Year Statement
H_2	Hydrogen
HP	High Pressure
HYD	High Hydrogen scenario
IDF	Industrial Decarbonisation Challenge
IGEM	Institution of Gas Engineers & Managers
IP	Intermediate Pressure
ISCF	Industrial Strategy Challenge Fund
LDZ	Local Distribution Zone
LNG	Liquefied Natural Gas
LP	Low Pressure
LTS	Local Transmission System
MP	Medium Pressure
MSOA	Middle Layer Super Output Areas
NAEI	National Atmospheric Emissions Inventory
NB	Nominal Bore
NOx	Oxides of Nitrogen
NTS	National Transmission System
OCGT	Open Cycle Gas Turbine
PRI	Pressure Reduction Installation
SMR	Small modular reactor
SO2	Sulphur Dioxide
SPF	Seasonal performance factor
SWE	South-West England
SWIC	South Wales Industrial Cluster
TPC	Transmission Planning Code
TSL	Temperature Sensitive Load
UK	United Kingdom
UKRI	UK Research and Innovation
WECA	West Of England Combined Authority

WPD	Western Power Distribution
WS	Wales South
WWU	Wales & West Utilities

UNITS OF MEASUREMENT

Bcma	Billion Cubic Metres per Annum
GW	Giga Watts
GWh	Giga Watt Hour
kscm/h	kilo Standard Cubic Metre per Hour (kSm3/h)
kWh	kilo Watt Hour
ktpa	Kilo Tonnes Per Annum
MCM	Million Standard Cubic Metre (million Sm3)
MCMD	Million Standard Cubic Metre per day (million Sm3/d)
MCMH	Million Standard Cubic Metre per hour (million Sm3/h)
MJ	Mega Joule
Mtpa	Million Tonnes Per Annum
MW	Mega Watt
Sm3	Standard Cubic Metre
tpd	Tonnes Per Day
TWh	Tera Watt Hour

SECTION B: STRATEGIC PLAN – ENERGY SYSTEMS CATAPULT

5. INTRODUCTION

5.1. BACKGROUND

In June 2019, the UK government implemented a legally binding target of Net Zero for UK greenhouse gas (GHG) emissions by 2050. Achieving this target will have far reaching implications across the UK's economy and society. The challenges of achieving this target go significantly beyond what was needed to meet the previous goal for 2050 of an 80% reduction from 1990 levels (ESC, 2020). The 'hard to treat' sectors can no longer rely on being 'safe' in the remaining 20%.

To achieve this Net Zero target and meet the UK's interim Carbon Budgets (CCC, 2020), the way energy is used, stored, converted, and transported across the country will need to change dramatically. Every sector and energy vector will need to go through a significant transition, including the gas and electricity networks.

The UK has an extensive network for transmission and distribution of natural gas which, in 2019, delivered around 500TWh of the energy to domestic, commercial, and industrial consumers, and almost 300TWh to electricity generators (BEIS, 2022). In energy terms, the UK uses around three times more gas than electricity and around 86% of UK households (MHCLG, 2021) use gas as their primary source of space and water heating. Today, natural gas can therefore be seen as a critical part of the UK energy system.

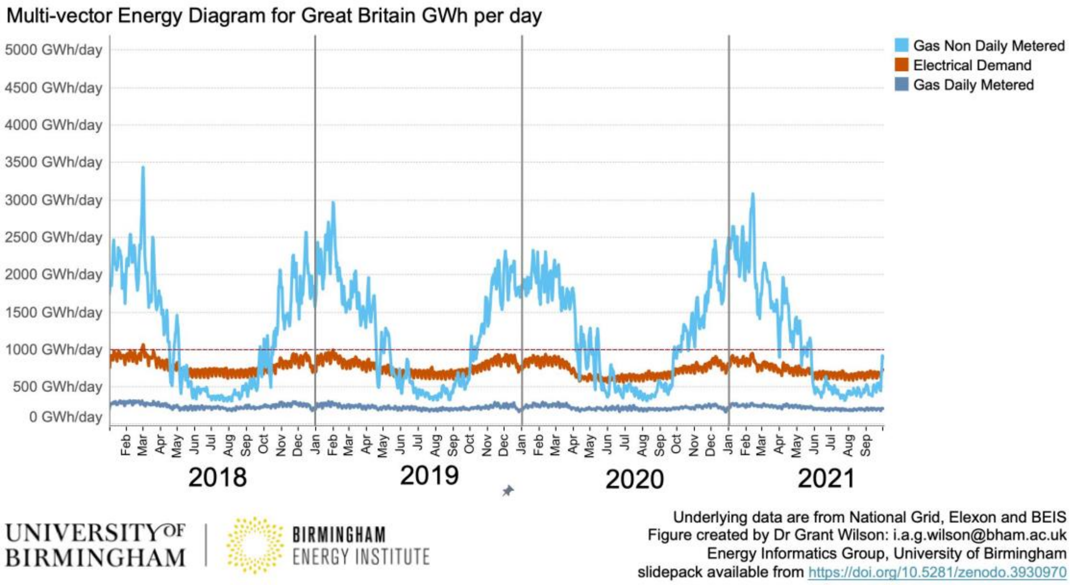

Figure 4: UK heat and electricity demand (University of Birmingham, 2021). Demonstrates the huge seasonal and daily variation in heat demand vs. a more predictable and stable electricity demand. This highlights the challenge of meeting heat demand with electricity.

Wales & West Utilities (WWU) have taken initial work on decarbonisation (Regen, 2020; Regen, 2021), but whilst uncertainty remains around the mix of technologies and gases in the network required to reach Net Zero, it is clear further work and analysis will be required to understand the next steps. Other organisations, including the ENA, have looked to establish credible pathways for UK gas networks (ENA, 2021). However, limited work has been undertaken to understand how these national pathways may translate to regional and sub-regional networks.

The purpose of this Strategic Plan is to address this analytical gap, developing three credible energy system pathway scenarios to 2050 for Wales and the South-West of England, to meet the

UK's carbon budget and ultimately Net Zero commitments. The implications of these scenarios for the WWU gas network have been analysed from a modelling perspective by the Energy Systems Catapult (ESC) and from an engineering perspective by Costain.

ESC has led on the development of the Strategic Plan, combining two of its national whole energy system modelling tools (Energy System Modelling Environment (ESME) and Infrastructure Transitions Analysis Model (ITAM)) to develop the scenarios and assess the implications for the existing gas network relative to 2050. Costain has led on the development of Conceptual Plan, taking ESC's modelling outputs and overlaying an engineering analysis to understand the practical implications of the energy system transition under each scenario.

The outputs of this project provide WWU with a series of det5.2ailed, consistent outputs, nested in the wider UK decarbonisation trajectory. The outputs and final report provide WWU with a consistent baseline evidence base to guide its strategic decision-making and engage various stakeholder and decision-makers.

5.2. STRATEGIC PLAN SCOPE

The scope of ESC's work within the project is the delivery of a Strategic Plan for WWU's gas distribution network in Wales and the South-West of England ("the WWU regions"). As noted in section 5.1, efforts have been made to establish credible pathways for the gas networks, in the transition to Net Zero, but limited analysis exists to interpret what this might mean beyond the national picture.

WWU required whole energy systems modelling of Wales and the South-West of England, to develop and assess three potential energy system pathways out to 2050. These scenarios would identify and analyse the key features of the energy and non-energy[1] systems through to 2050, in 5-yearly time periods. The scenarios would be consistent with the UK meeting its 2050 and interim decarbonisation targets under Carbon Budget 6 (CB6).

Subsequent analysis would then set out the implications of the three scenarios for the gas transmission and distribution networks in the WWU regions. WWU sought analysis of the network implications at two levels: for the two WWU regions (Wales and the South West of England); and for nine sub-regions, defined by WWU:

- North Wales
- Mid Wales
- South Wales
- West of England Combined Authority (WECA)
- Gloucestershire
- Wiltshire
- Somerset
- Devon
- Cornwall

The Costain sub-regional Conceptual Plans are also undertaken for these sub-regions, but treat Gloucestershire, Wiltshire, Somerset and WECA as a single sub-region, for analysis as a Conceptual

[1] There are several key "non-energy" system components that will contribute to the UK and Wales's decarbonisation pathways. These include land-use change (e.g., reforestation, peatland restoration) which can be important carbon sinks. It is therefore important that these are captured within the whole systems modelling.

ESC's modelling approach to the Strategic Plan

To achieve the project scope set out in Section 5.2, the ESC has applied two of its whole system models, the Energy Systems Modelling Environment (ESME) and the Infrastructure Transitions Assessment Model (ITAM).

Whole system modelling for the WWU regions

ESME is a UK whole system model with 12 onshore modelling regions and 13 offshore modelling regions. Two of the onshore modelling regions are the country of Wales and the South-West of England. The regional boundaries within ESME map extremely closely to WWU's network boundaries, allowing regional whole systems analysis to be extracted and analysed for each scenario, out to 2050.

ESME covers:

- Energy service demands across all of transport (road, rail, shipping, aviation), buildings (domestic, public, commercial) and industry (nine sectors).
- Regionally specified energy resources such as wind, solar, biomass, as well as fossil and nuclear; intermediate technologies to convert these resources into useful fuels/vectors such as power, hydrogen, and district heat to satisfy the regional demands; all mediated through transmission and distribution network and storage infrastructure.

ESME also accounts for non-energy emissions such as land use, crucial for a coherent economy-wide Net Zero scenario. Output charts summarise the relevant installed capacities of technologies and energy supply and demand quantities in 5-year time steps to 2050.

Network analysis for the WWU sub-regions

ITAM takes least cost net zero whole energy system designs from ESME and translates these to form indicative 2050 national infrastructure requirements, based upon local characteristics, that allow those energy systems to be realised. The two fundamental steps used in this project to provide indicative infrastructure requirements are:

1. Translation of model outputs at regional level and distribution of demands at a fine granularity within that region – defining peak energy demands from each demand sector within each area.
2. Definition of indicative infrastructure networks needed to meet those peak demands – including electricity, hydrogen, gas, district heat and CO2 networks. Comparison of how these networks differ from existing network infrastructure and what transitional steps are needed (e.g., decommission, reinforce, build new). Aggregation of these infrastructure specifications into bills of quantities at local government scale.

The bill of quantities derived within ITAM includes elements that are not typically modelled directly in coarse-grained whole energy system models. These include electricity and gas connections, network abandonment costs and repurposing interventions. It disaggregates ESME outputs into greater spatial granularity, allowing for more detailed sub-regional analysis.

Figure 5: Overview of the ESC modelling approach

5.2.1. OUT OF SCOPE

There are several areas that were outside the scope of this project:

- ESME and ITAM are strategic planning tools, not market/dispatch models, power systems or hydraulic models. Therefore, detailed network operational analysis was out of scope of this project. The Strategic and Conceptual Plans are intended by WWU to provide the foundations for further detailed network planning analysis, that will need to be done after the completion of this project.
- Materials evaluation of pipelines to transport hydrogen (e.g., from materials of construction and safety point of view) is not part of this project. Certain assumptions are made around the suitability of materials, and these are referenced in the appropriate sections.
- The Strategic and Conceptual Plans are limited to the gas transmission and distribution networks, meaning that the electricity network is out of scope. This said the whole systems modelling (i.e., ESME outputs in section 4), covers all aspects of the energy system and present a view on the implications for the electricity sub-system for each scenario.
- Engagement has taken place with expert interviewees as part of the project, but a more formal stakeholder engagement process has not been undertaken to agree scenarios and iterate modelled outputs.
- The development and analysis of outputs at an individual Local Authority (LA) boundary level have not been developed as part of this project.
- The analysis does not assess the distributional impacts across society, such as the recovery of network costs, how this paid for and how it falls on different parts of society.

5.3. LIMITATIONS OF THE MODELLING APPROACH

It is challenging to devise a single modelling methodology that includes full coverage of the whole energy system but also is able to provide sufficient granularity regarding energy infrastructure to inform tangible real-world network decisions, whilst assuring consistency with a low-cost route to Net Zero at the UK level.

The scope, scale and detail covered by this project are significant. The whole system modelling is undertaken for the UK in 5-yearly time slices, out to 2050. Implications for Wales and the South-West of England are then extracted. This is further deconstructed for the sub-regions noted in Section and to assess the 2050 gas network implications.

The approach adopted in the project, using two complementary whole energy system models (ITAM and ESME – see Figure 5) and grounding their findings against engineering expertise, overcomes much of this challenge. However, it remains important to understand the remaining limitations. In particular, the idea that the network modelling is derived from ESME pathways requires an understanding of the aims and approaches inherent in the two models.

These limitations are listed in full in 'Appendix C – Modelling Limitations', but note should be made of the approaches taken regarding representation of heat in buildings (in particular with regards to the operation of heat pumps and hybrid systems), representation of industry and its decarbonisation options, and the respective methods employed within ESME and ITAM to represent energy infrastructure. An important implication of these limitations is uncertainty around the cost optimality of the high level of hybrid hydrogen boiler/heat pump systems seen in the ELE scenario and the correspondingly low numbers of disconnections from the gas grid. This uncertainty is lower, but still present in the other scenarios.

5.4. INSIGHTS FROM THE EVIDENCE REVIEW

To ensure the project built on the learnings from previous work, an evidence gathering process was initially undertaken. This is not the first project to look at the energy transition and its implications for gas networks, so it was important to reflect on the outputs and insights from previous work and the process that had derived these. The evidence gathering process was composed of two parts, a literature review and a series of expert stakeholder interviews.

This evidence gathering provided an improved general understanding of the challenges and opportunities faced by the UK energy system in general and specific to the WWU region, as well as providing some key insights that have been reflected in the project, such as in the development of the scenarios and in the assumptions to use in the modelling.

The first part of the evidence gathering phase of the project was a review of other energy system scenario work covering Wales and the South-West of England, and other relevant reports. Examples include 'A Combined Gas and Electricity DFES Assessment for South Wales' (Regen, 2020), Regional Growth Scenarios for Gas and Heat' (Regen, 2021), and 'Gas Goes Green' (ENA, 2021). The list of literature shortlisted and reviewed is at Appendix A.

This was conducted using a framework devised to ensure the systematic collection of features such as: methodology, inputs, outputs, and findings. This was led by ESC with input from Costain and WWU to ensure all key publications were identified for review.

To build upon the insights gained from the literature review, a series of semi-structured interviews were carried out with subject matter experts from across the sector. The full list of interviewees can be found in the Appendix. Speaking to these key stakeholders allowed further direct input into the scenario framework development, and discussion of some of the specific challenges and opportunities faced in Wales and the South-West of England.

A references list for the literature reviewed and list of interviewees can be found in Appendix A and Appendix B respectively. The key findings are summarised below in sections 5.4.1 to 5.4.7, organised under key themes.

5.4.1. SCENARIO FRAMEWORK INSIGHTS

Narrative and outcome-based scenario approaches are most effective when combined

The use of scenarios is a well-known approach to explore the future of the energy system. There were, therefore, several other studies to gain insights from. A point of difference between studies centred around the scope of the scenarios and subsequent analysis – this varied considerably depending on who the work was carried out by and undertaken for.

Variations occurred with respect to the time horizons analysed; the geographical area; the sector of analysis; and energy vectors. Another variation between the different pieces of work was the framework on which the scenarios were defined. Two ways of structuring the scenarios for this study emerged, to mesh with the whole system modelling approach and available tools:

- **Narrative-based scenarios (input driven):** A narrative is formed to explain how the future may unfold in terms of the inputs and assumption used.
- **Outcome-based scenarios (output driven):** Scenarios are defined in terms of selected key outputs of the modelling. The inputs are then varied to arrive at those scenario outcomes.

The work of National Grid ESO (NG ESO, 2021), Climate Change Committee (CCC) (CCC, 2020) and Energy Systems Catapult (ESC) (ESC, 2020) all use a narrative-based approach and a similar framing where the scenarios are based on the variation of two types of parameters – the level or speed technological change and the level of behavioural/societal change assumed. By default, this framing was also carried over into much of the work of the gas and electricity networks in their distribution future energy scenarios (DFES). Figure 6 shows National Grid Electricity System Operator's (NG-ESO) framework.

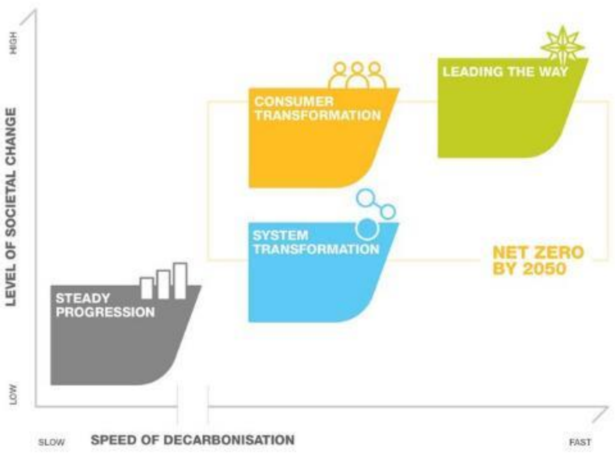

Figure 6: Scenario framework adopted in National Grid ESO Future Energy Scenarios. (NG ESO, 2021)

Alternatively, some of the work carried out by Regen (Regen, 2020), ENA (ENA,2021) and CR Plus (CR Plus, 2020) used outcome-based scenario definitions. Here, the interplay between different balances of hydrogen and electrification were investigated and the assumptions adjusted to achieve the outcome, enabling a particular sector to be tested. These studies tended to look at the issues from a bottom-up viewpoint, whereas the more narrative based, input driven scenarios looked from top down. However, it was recognised in the literature, that a combination of the two may deliver the most robust insights (CR Plus, 2020).

During the project's expert interviews, stakeholder feedback provided more detail on scenario approaches. One point made was that the scenarios should ideally be different shades of the same thing. If this is done, it is possible to use them to find commonalities and therefore low regret actions. Another justification for this was that no extreme case is likely to come to fruition. Whilst this was an outcome of the interviews, we should also view this against the ability of previous scenario projects to capture major developments in the energy system (e.g., falling cost of renewables). It is now commonly accepted that the future will involve multiple solutions working in parallel.

5.4.2. INDUSTRY INSIGHTS

Decarbonisation of Industry is a huge challenge

Nationally, industry is one the three big energy use sectors, along with transport and domestic demand. This is also the case in the region covered by the WWU gas distribution network. As with the rest of the UK, industry in this region faces a multi-faceted challenge of reducing energy demand, switching that energy demand away from GHG emitting sources, and addressing the issues around process emissions (CR Plus, 2020).

The first two of these – demand reduction and vector switching – can be achieved through continued process efficiency improvements and a move from fossil fuels to electricity or hydrogen for process heating (Arup, 2021). Although, there are notable practical challenges. The third – process fossil fuel use – is likely to require significant process change and the development and use of Carbon Capture and Storage (CCS) (CCC, 2021).

However, to the benefit of the WWU region, industrial activity is centred around industrial clusters where these challenges can be tackled on a manageable geographical scale. The activity is also skewed towards a small number of very large sites, with research indicating, for example, that over 90% of South Wales's industrial emissions originate from just three sites – a steelworks, a cement works and a refinery (CR Plus, 2020).

Interviewees added to these points by reiterating the need to develop CCS to deal with the emissions from process fuel use. Although, this comes with the wider locational CCS challenges around lack of storage sites and routes for pipelines. They also highlighted the need to consider plant phasing when thinking about vector switching. Most plants will have multiple processes and converting all in one step is not feasible. Therefore, there is likely to be a transitionary phase with multiple vectors providing energy as processes convert from natural gas to hydrogen, for example. This has wider implications on network planning. It was also pointed out that natural gas to H_2 is not the only possible vector switch, and that there is a big opportunity for electrification of process heat.

5.4.3. HEAT INSIGHTS

Regionality is important and the future is highly uncertain

It is generally accepted that the continued combustion of natural gas in homes for space and water heating is not compatible with the UK's Net Zero target (NG ESO, 2021) (CCC, 2021) (ESC, 2020). This leaves the future options of some combination of electrically driven heating systems (e.g., heat pumps, electric resistive heating), heat networks (driven by waste heat, heat pumps hybrid hydrogen and electrically driven systems), or the distribution of hydrogen to homes for local combustion.

There may also be transitionary roles of bio-methane in reducing the GHG intensity of natural gas (through blending) (Regen, 2021), and potentially for islanded networks (ENA, 2019). However, from a whole system perspective, it is likely that the bio-resources used to generate bio-methane would be better used elsewhere in the energy system (for example, through electricity generation with CCS – BECCS) (NG ESO, 2021) (CCC, 2020), particularly where they can be combined with carbon capture to provide negative emissions and the resultant energy carrier is valuable to the system.

The proportions of the mix of technologies likely to meet future heating demand is highly uncertain, with hydrogen seeing some of the widest variations in potential adoption in the literature. Different scenarios in the NG ESO's Future Energy Scenarios (FES) work puts the domestic hydrogen consumption anywhere between less than 5% of today's domestic heat demand to over half of today's domestic heat demand (NG ESO, 2021). The literature consistently identified the short-term (5-10 years) applications for hydrogen are likely to be in industry (as discussed above).

The stakeholder interviews confirmed this view of high uncertainty in approaches to meeting future heating needs. They also highlighted the non-technical and non-economic aspects that will play into the domestic heating pathway. A large part of the heating system decision is in the hands of policy makers and consumers but will also depend on the ability of supply chains to scale up (BEAMA, 2022). Without supportive policy signals and consumer propositions to drive adoption, any transition is going to be slow.

5.4.4. TRANSPORT INSIGHTS

More certainty than seen in other sectors

The consensus from across the literature review is that most of the personal transport will transition to battery electric vehicles (ENA, 2019) (Arup, 2021) (NG ESO, 2021) (CCC, 2020) (ESC, 2020) (EV Energy Taskforce , 2022). However, there is less certainty around long range HGVs and buses, for which hydrogen may be the most appropriate option (Arup, 2021). This is one sector where there is an element of policy clarity, with a ban on new internal combustion engine (ICE) cars in 2030 and commitments to improve charging infrastructure (BEIS, 2020).

5.4.5. ELECTRICITY SECTOR INSIGHTS

Mix of renewable solutions to deal with increased demand

Electricity generation in Wales is expected to be 100% renewable by 2050, according to much of the literature reviewed (CCC, 2020b). However, some have highlighted the need for dispatchable generation to ensure supply can meet demand, with natural gas with CCS or H_2 playing their part in providing this (Arup, 2021). The electricity network of the UK is highly interconnected, with not all regions being suited to all generation types. Therefore, the system should be planned to capitalise on this diversity.

The importance of electricity generation was highlighted in many of the interviews. The impact of electrification of transports and parts of heat will lead to increased demand and only yield emissions savings if the electricity supply is decarbonised. Again, it was pointed out that a mix of solutions will be needed.

5.4.6. BIO-ENERGY INSIGHTS

Likely to be competing demands for this primary resource

Some of the literature reviewed suggests that there is a role for bio-methane injection into the natural gas network (ENA, 2021). However, the consensus from most of the work suggests that this is not likely to be a significant part of the pathway to Net Zero. They highlight other competing demands for the primary resource – BECCS and bio-aviation fuel – offer more value on a system level (NG ESO, 2021) (ESC, 2020).

5.4.7. OTHER CONSIDERATIONS

Unlikely to be a purely technology driven choice – the future for networks is uncertain and there are both challenges and opportunities throughout

Many of the interviews highlighted considerations beyond the normal scope of energy systems analysis. These included impacts on air quality, the need for regional solutions, considerations of citizens' desires, the risk that regional actions may overtake national plans, and that further innovation is likely to come along and disrupt anything we foresee today. It was not suggested that these be elevated to the same importance as the ones already under consideration, rather that they should be taken account of in wider analysis of the modelling outputs.

As well as these, there were several practical considerations, which are considered during the later stages of this project in the development of the sub regional plans. These included the practicalities of gas network conversion to carry a different gas; the different operating regimes and duty cycles that might be in play in a gas system which is supplementing the electricity system; the challenge of meeting peak heating demands; and the need to consider energy storage.

5.5. SCENARIO FRAMEWORK

The use of scenarios in energy system modelling is a commonly used approach to help stakeholders understand and refine their own decision making, or to inform interested parties more widely. Although they are consciously not deemed to be forecasts, scenarios offer multiple viewpoints of how uncertain elements of the system might develop in the future, and they facilitate consideration of the practical implications of such developments. They allow risks, dependencies and consequences to be exposed to stakeholders, and help build consensus around how the transition to Net Zero might develop.

As noted earlier, there are multiple approaches available to help with constructing scenarios, but two high-level approaches were explored in this project: narrative and outcome-based scenarios. Through a series of discussions with WWU and other key stakeholders, it was determined for this study that an outcome-based scenario framework would be most appropriate, focussing on different levels and types of hydrogen use across the energy system (see Figure 7), integrating well with the practical considerations within the conceptual plans. For the implementation adopted within this project, this framework impacts the choice of heating solutions for buildings and the consequences for the future of the gas distribution network. All other uncertain features of the energy system – end-user demands, technology availability and cost, energy resources – were agreed to be fixed across the scenarios and in alignment with ESC's techno-optimistic Clockwork scenario.

As a result, the scenario framework is built upon a single guiding axis (see Figure 7) that characterises the mixture of heating systems ultimately deployed across the UK. This framework prompts selection of two natural scenarios, representing a preference for heating solutions of one form or another. These two scenarios are:

1. 'High Electrification' [ELE]: representing a scenario where electric heating solutions supply the majority of heat in volume terms. Hydrogen boilers will predominantly operate as part of hybrid systems in which the heat pump component supplies the majority of heat during summer and winter.
2. 'High-Hydrogen' [HYD]: representing a scenario where hydrogen-based heating solutions are preferred nationally and deliver the majority of heat to homes and businesses

A third, 'Balanced' [BAL] scenario is also included, representing a mixed or non-homogenous set of heating solutions across the UK, and residing between the more extreme ELE and HYD scenarios, but closer to HYD. This represents a scenario where policy and consumer preferences are more varied and do not lead to a clear settlement on a predominant heating system.

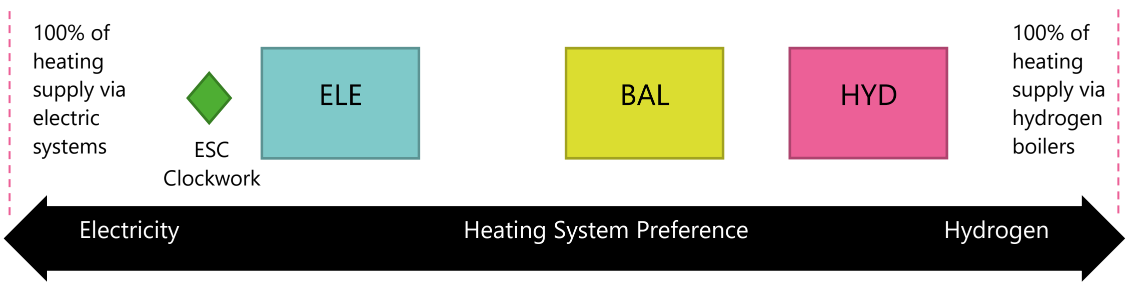

Figure 7: Scenario Framework

This scenario framework both informs and is informed by the modelling approach adopted in this project. Exploratory ESME runs were carried out to understand how well aligned these scenarios are to historic ESC modelled Net Zero pathways, and to help choose how far along the axis towards full electrification or hydrogen each scenario should reach. Early in the scenario development process, it was agreed that ELE and HYD should represent plausible but not extreme scenarios, with barriers to complete electrification (e.g., challenges for the least efficient buildings) or hydrogen supply (e.g., off-gas buildings) assumed to persist.

In each scenario, choices around domestic energy efficiency remain a decision informed by ESME rather than imposed as part of the scenario narrative. Different packages of whole-house retrofit measures can be selected if appropriate.

ESC's previous scenarios follow a predominantly techno-optimistic philosophy wherein innovation within technologies progresses apace, delivering cost and performance improvements and assuming sufficient appeal of emerging technologies to consumers. These tend to envision Net Zero energy systems where electric systems are critical for the provision of high volumes of heating and where boiler systems (or backup systems of hybrid heat pumps) are equally critical, providing key system capacity. Exploratory ESME simulations for this study confirmed this position, with ELE proving similar in ethos to the historic central ESME least cost solution.

The other two scenarios were then used to look at what one would need to believe for the greater hydrogen deployment outcome in these scenarios to be realised. Section 6.1.2 discusses the assumption changes that were necessary to implement these outcomes. Against this backdrop, BAL and HYD can be considered to be futures wherein the projected least cost solution cannot be realised in full due to practical considerations – lack of policy support, disruption, consumer preferences, network reinforcement and supply chain constraints all influence the transition of the heating sector from high to zero carbon, at the point of delivery.

The extremes of this framework represent two scenarios in which the role of gas distribution network operators is anticipated to be very different, offering a useful starting point for the Strategic and Conceptual Plans central to this study. Although the extent to which hydrogen is adopted in the HYD scenario is not fully defined within the framework, it does represent a future with an optimistic view of hydrogen's role in meeting energy service demands – primarily domestic heating. This is a scenario where alternative technologies such as heat pumps are less favoured by the consumer.

Table 2 shows the scenario narratives, highlighting the technical, policy and consumer drivers for each. As can be seen, the scenarios primarily focus on the impact of different levels of low CO_2 heating systems. This has been done as domestic heating demand was seen as the most significant factor influencing the future of the gas distribution network which WWU operates. Although there are other users of the network – industry, commercial, power generation, etc. – residential connections account for the largest share of the network.

ELE	BAL	HYD
Policy support for air source heat pumps (ASHPs) is in place and propositions are developed which make the transition from natural gas boilers to ASHPs attractive to consumers. Like ESC's global assumptions.	Represents a mid-point between ELE and BAL in terms of ASHP deployment. Policy support is mixed, promoting different solutions in different areas and offering consumers viable choices.	The deployment of ASHPs is lower than anticipated due to constraints on the electricity distribution network, a lack of policy support from government and lack of consumer acceptance of the propositions from installers.

Table 2: Scenario narratives

As discussed above, the high electrification scenario is similar in its assumptions and outcomes to ESC's standard Clockwork scenario. This work has explored the bounds of what might happen if some of the standard assumptions are pushed beyond ESC's normal range.

The three scenarios are used in the modelling work as described in the next section to investigate some of the uncertainty around the future energy system. The high-level scenario framework and scenario narratives discussed above are developed into a detailed set of modelling and system assumptions.

6. REGIONAL ANALYSIS

6.1. WHOLE SYSTEM MODELLING

6.1.1. ESME MODEL OVERVIEW

ESME is a linear optimisation model of the whole UK energy system. The optimisation generates the lowest-cost energy system designs which satisfy constraints such as energy service demands for buildings, transport, and industry, subject to CO_2 budgets. It is focussed on the physical components of such a system – infrastructure, energy flows and associated costs – and does not look at other layers of the system such as commercial aspects or communications between actors.

The philosophy within ESME is of modelling the UK as an energy island. This means that ESME designs do not rely on cross-border electricity infrastructure to absorb excess generation or import electricity when indigenous sources are not available. Policy-neutrality is a fundamental principle when using scenarios built in ESME, wherein minimal second-guessing of how policy could de-risk investment in the future takes place. By adopting this principle, the energy system can be thought of as being designed centrally, and technology risk is reduced. Because ESME is designed to address long-term aspects of the system design, the representation of the average days is too coarse to include practical features of supply and demand balancing; for example, dividing typical days into five different time-slices (morning, afternoon, early evening, late evening and overnight) does not allow for sub-hourly system balancing to be represented in the model.

Importantly, ESME includes a multi-regional UK representation and can assess the infrastructure needed to join up resources, technologies and demands across the country. This includes transmission and distribution networks for electricity, gas and hydrogen, and pipelines and storage for CO_2. However, it should be noted that ESME is not a network model. This multi-region feature means we have been able to evaluate decarbonisation pathways for Wales and the South-West of England as part of and consistent with the transition of the wider UK energy system to Net Zero[2].

6.1.2. ASSUMPTIONS

This section discusses the assumptions used in the scenarios, including deviations from the standard set of model inputs typically used by ESC, and specific changes used to design the three distinct scenarios. A full description of the key assumptions is presented in the assumptions log, published with this report.

These assumption deviations were applied to the whole of the UK not just Wales and South-West England. So, there are no significant changes in technology cost and performance between the UK modelling regions, and any scenario adjustments are defined at a UK level rather than in Wales and South-West of England. The exception is where regional capacities of key technologies (e.g., offshore wind) for the base year were applied to align to real world data. It is important to state that 2015 is the base year, the first modelled year in ESME is 2020, therefore generation in the pipeline must be captured / ensured built. Looking forward from 2015, energy output in 2020, as a result of demand assumptions used in the model, are reflective of pre-COVID estimates.

[2] It is worth noting that within a UK transition to net zero, there is no requirement for every sub-region to follow the exact same pathway to net. A combination of net negative and net positive regions is perfectly compatible with Net Zero at a national level but all sub-regions will need to be close to Net Zero.

Variations from standard ESC assumptions

The challenge with modelling pathways to 2050 lies in assumptions regarding:

- How much current technologies improve in performance and/or cost from today.
- Characteristics of novel technologies in terms of performance and first year of deployment.
- Handling of uncertain energy demand projections.

Technology cost and performance in ESME have been informed over the past 14 years by engineering expertise and insight gained first-hand from projects run by ESC and before that the Energy Technologies Institute (ETI). Where first-hand data and evidence has not been available, secondary data sources from government, academic and industrial literature have been used (ETI, 2017).

Based on expert interpretation of available evidence, ESC typically runs ESME from a position of techno-optimism. This means that innovative methods and developments that can lead to continued improvements in technology performance are assumed to occur. Engineering insight determines what these innovations might be and when they might happen; and quantifies the performance and cost improvement.

For ESC, as a leading technology and innovation centre, this techno-optimistic standpoint helps to identify areas of the energy system where innovation can deliver the most value and opportunity. For different studies, it is considered important to review and moderate the assumed level of innovation of different technologies. This has been done in this project where three key deviations from the ESC standard set of assumptions were made:

- The assumed improvement in coefficient of performance (COP) over time for heat pumps has been adjusted to be in line with those defined in the BEIS Future Support for Low Carbon Heat report (BEIS, 2020).
- Small modular reactors (SMR) have been constrained such that they are only able to supply electricity as opposed to also being able to support district heating as well.
- District Heat Network (DHN) rollout is limited to lowest cost networks (ETI, 2012), whereas the ESC assumes, for additional cost, networks can be expanded to include more sparsely populated areas.

The assumptions restricting nuclear SMR operation mode to electricity supply only and restricting DHN to lowest cost networks both present barriers to DHN rollout (e.g., low public acceptance and failures in coordinating activities with potential heat offtake from small modular reactors). More details on these assumptions are provided in Table 3.

Table 3: Project-specific assumptions agreed with WWU for the project

Assumption	Description	Rationale
Heat pump COP	ESC original assumption is for 20% improvement in annual average seasonal performance factor (SPF) from 2010 to 2050 (SPF 3.6 in 2050). This has been updated to annual average SPF 3 in 2050 from 2.5 in 2020.	Aligned with BEIS Future Support for Low Carbon Heat report (BEIS, 2020)

Small modular reactors (SMR) provide electricity only	ESC original assumption allows small modular reactors to supply both electricity and heat for district heat networks. This has been modified so that SMRs do not supply heat to district heat networks	Uncertainty around public acceptance of SMRs particularly if located in close proximity to population centres, which would be necessary for a viable district heat network supplied with waste heat from SMRs
Lowest cost district heat networks	Only the lowest cost heat networks are rolled out	Level of coordination needed which may be challenging except in high density urban areas which will have the lowest cost.

These modifications to the standard set of ESME assumptions were applied to all three scenarios.

Industrial decarbonisation assumptions

ESME draws on evidence gathered by UKERC on industrial decarbonisation and fuel-switching options. This evidence is some of the most robust related to UK decarbonisation. It not only identifies the possible options open to industry but importantly the challenges (economic and technical) too. The upshot is that residual natural gas use is assumed to remain in industry because some processes are currently unable to fully switch to electricity or hydrogen (see sections 6.2.6 and 0).

High Electrification (ELE) scenario assumptions

In the High Electrification scenario, most heat, in terms of volume, not capacity, in residential and non-domestic buildings is supplied by electric systems such as heat pumps and electric resistance heaters. This is a relatively unconstrained scenario (except for the assumptions outlined in Table 3) and produces outputs typically demonstrated in heating sectors seen in scenarios subject to a similar set of assumptions in ESME.

The High Electrification scenario assumes hydrogen boilers will operate at capacity during a cold stress event. These boilers will predominantly operate as part of hybrid systems in which the heat pump component supplies most heat during summer and winter, but hydrogen is critical to operation when the heat demand is high.

There are no other scenario specific changes made to the High Electrification scenario.

Balanced (BAL) scenario assumptions

In the Balanced scenario, broadly equal amounts of heat are supplied by electric and hydrogen-based heating systems by 2050. This reflects a world in which heat pump uptake is stalled by consumer perception and a lack of supporting policy. Details of the key scenario-specific assumptions are given in Table 4.

Table 4: Scenario specific assumptions for Balanced (BAL) scenario

Assumption	Description	Rationale
Restricted electric heating	No new electric resistive heating (ERH) systems are installed. Once old systems reach the end of their life, they are replaced with alternative heating systems.	People are cautious about installing unfamiliar heating systems like heat pumps. Without incentives or other appropriate policy mechanisms, even

	Air source heat pump (ASHP) rollout is restricted to approx. 2/3 of the deployment seen in High Electrification. Ground source heat pumps (GSHP) are not deployed	less cautious consumers struggle to make the move to heat pumps. Those that do install heat pumps opt for ASHPs due to lower costs and relative ease of install compared to GSHPs. Electric resistive heating systems are replaced at the end of life with alternatives.
Hydrogen boilers are load following	Hydrogen boilers are permitted to operate in the same manner that gas boilers today are (i.e., they meet both baseload and peak heat requirements). However, it is still possible for them to be operated as part of hybrid HP systems	People prefer to make the switch to hydrogen boilers on the grounds that these are more familiar in look and feel to gas boilers.

High hydrogen (HYD) scenario assumptions

In the High Hydrogen scenario, most of the domestic heat supplied in the UK is from hydrogen-based heating systems by 2050. This reflects a world in which their uptake heat pump uptake is stalled by consumer perception and a lack of supporting policy[3]. Details of the key scenario-specific assumptions are given in Table 5.

Table 5: Scenario specific assumptions for High Hydrogen (HYD) scenario

Assumption	Description	Rationale
Restricted electric heating	No new electric resistive heating (ERH) systems are installed. Once old systems reach the end of their life, they are replaced with alternative heating systems. Air source heat pump (ASHP) rollout is restricted to approx. 1/3 of the deployment seen in High Electrification. Ground source heat pumps (GSHP) are not deployed	People are cautious about installing unfamiliar heating systems like heat pumps. Without incentives or other appropriate policy mechanisms, even less cautious consumers struggle to make the move to heat pumps. Those that do install heat pumps opt for ASHPs due to lower costs and relative ease of install compared to GSHPs. Electric resistive heating systems are replaced at the end of life with alternatives.
Hydrogen boilers are load following	Hydrogen boilers operate in the same manner that gas boilers today are (i.e., they meet both baseload and peak heat requirements). However, it is still possible for them to be operated as part of hybrid HP systems	People prefer to make the switch to hydrogen boilers on the grounds that these are more familiar in look and feel to gas boilers and may have lower fixed costs.

[3] It should be noted there is not an equivalent restriction on hybrid systems, which are a combination of a smaller heat pump and hydrogen boiler.

6.2. SCENARIO ANALYSIS OUTPUTS

6.2.1. DECARBONISATION PATHWAYS FOR WALES

The whole system modelling shows that decarbonisation in Wales is achieved in two key ways:

1. Adoption of low and zero carbon technologies in the main energy system sectors (e.g., on/offshore wind, hybrid heat pumps and hydrogen fuel switching and CCS in industry).
2. Negative emissions generated by Bioenergy with Carbon Capture and Storage (BECCS) and in the land use sector (e.g., by afforestation).

Figure 8 shows the rate of decarbonisation occurring in all the main sectors in Wales and the extent of negative emissions generated by BECCS used in hydrogen production. Table 6 provides a summary of the decarbonisation options in each of the sectors with key differences between the scenarios drawn out. We can see that there are very few key differences between scenarios, with the distinguishing assumptions between them driving few wider system-level differences, beyond the heating sector. However, within sectors, some more meaningful differences emerge, and these are explored in the following sub-section.

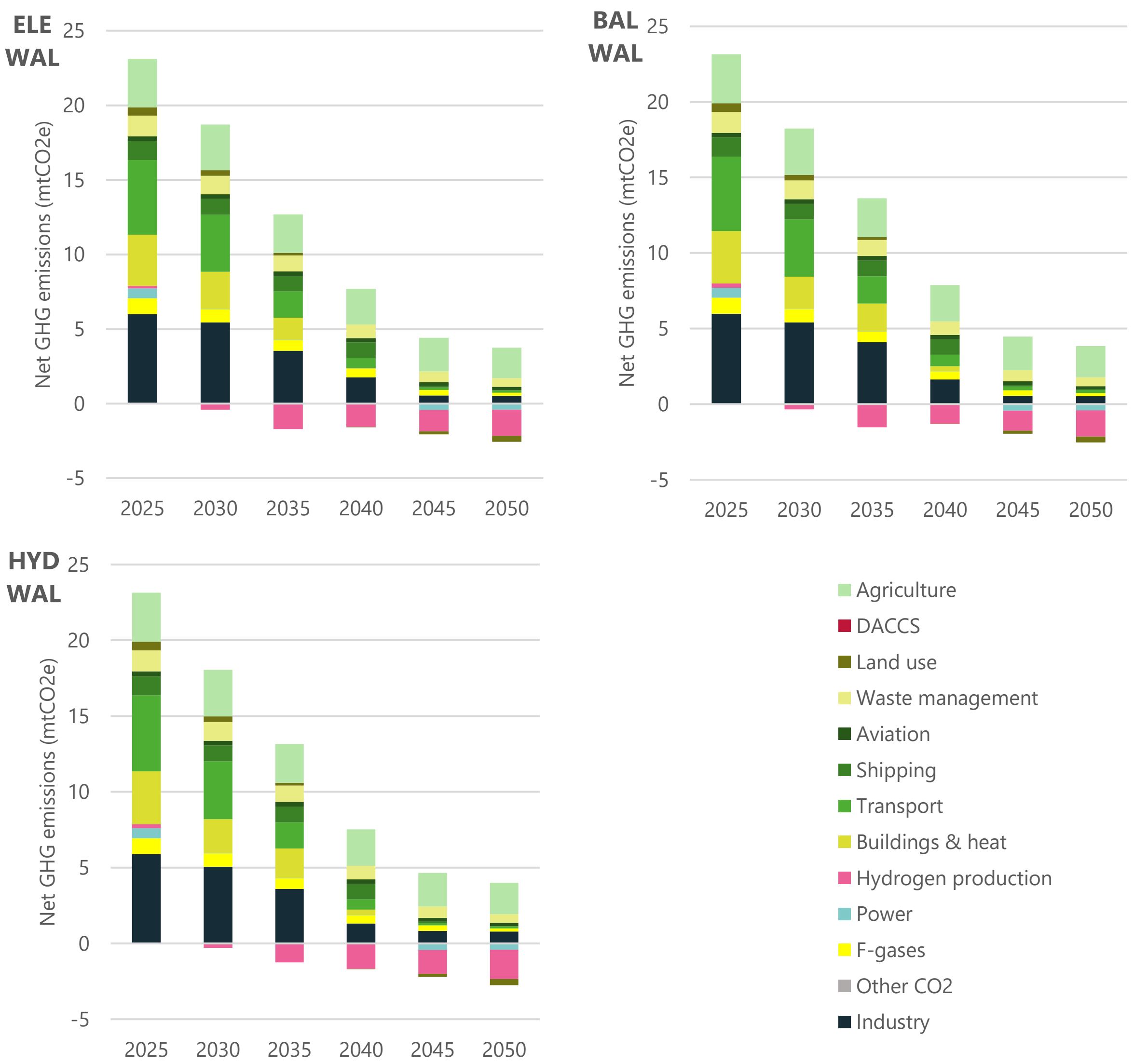

Figure 8: Net GHG emissions in Wales from 2025-2050 for ELE, BAL and HYD scenarios

Table 6: Summary of decarbonisation in Wales by sector

Sector	Description
Power	The power sector decarbonises quickest becoming Net Zero by 2030 in all scenarios and becomes net negative in 2045 as a result of energy from waste (EfW) with CCS. Early decarbonisation is largely driven by reduced output from CCGTs, which cease to supply baseload electricity from mid-2020s. Energy generation over the year in Wales is not sufficient to meet Welsh electricity demand until 2045. Imports from other parts of the UK are therefore necessary to fulfil Welsh electricity demand. In ELE, the main source of electricity generation is from renewables, particularly offshore wind, which reaches 3GW by 2035. This is supported by dispatchable generation in the form of legacy unabated CCGTs up to 2040 and 2GW hydrogen turbines after CCGT capacity has been retired. In BAL and HYD, electricity generation is also met by renewables but only 2GW of on and offshore wind is installed. Instead, bulk generation is met by 1.2GW and 2GW nuclear gen. III plant in BAL and HYD respectively. This is needed to supply higher electricity loads in industry and hydrogen production compared to ELE.
Heating	Residential heat decarbonises next becoming zero carbon in 2040 and 2045 in ELE and BAL/HYD respectively. This is caused by a shift from natural gas as the dominant supplier of residential heat to a combination of three main zero carbon energy vectors (zero carbon at point of use): electricity, hydrogen and district heating.
Transport	The transport sector is next to decarbonise with the 2030 national ban on new ICE sales applied to all scenarios. A small number of plug-in hybrid vehicles remain to 2050, which maintain a demand for liquid fossil fuels, hence road transport never fully decarbonises in the 2050 timeframe. Shipping sees a steep decrease in emissions in 2045 as a result of hydrogen fuelled ships being available on a commercial scale. Residual emissions remain in aviation.
Industry	Industrial emissions decrease steadily to 2035 after which there is a sharp decrease. This is a result of a big switch to hydrogen from liquid fuel and natural gas seen in all three scenarios. Industrial CCS is also critical to ensure emissions from industry are eliminated. Emissions continue to fall but are lowest in ELE and BAL in which BECCS in industry is able to deliver negative emissions (HYD reserves more biomass for hydrogen production).
Negative emissions	Negative emissions are delivered by BECCS for hydrogen production as well as some from land use as a result of afforestation (note that afforestation is a hard-coded assumption and does not change between the scenarios). Negative emissions create headroom for other areas of the energy system to continue to emit GHGs. This is particularly important for difficult or costly parts of the system to decarbonise such as aviation, industry and agriculture. Negative emissions are the reason why a net zero energy system is still possible with residual fossil fuel use in parts of the system. Despite producing negative emissions, Wales remains a net emitter of GHG throughout the UK. This is a result of the modelling approach optimising energy system design to deliver a Net Zero UK, which could entail some regions being net negative and some being positive emitters. This output does not seek to make suggestions about Welsh GHG policy or targets, it is simply an outcome of these particular scenarios.

6.2.2. HYDROGEN PRODUCTION IN WALES

There are four broad categories of hydrogen production modelled in ESME:

- Reformation of natural gas both with CCS (also called blue hydrogen) and without (referred to as grey).
- Electrolytic hydrogen (also referred to as green hydrogen, when powered by renewable electricity, but sometimes referred to as yellow when powered by grid electricity, which may or may not rely on fossil fuel powered generation).
- Gasification of biomass both with and without CCS.
- Advanced nuclear reactors able to switch between electricity and hydrogen production modes. This can either be via high temperature electrolysis or thermochemically, such as in the sulphur-iodine cycle.

ESME's overarching challenge to deliver an energy system that satisfies demands whilst meeting GHG targets for the lowest system cost[4] produces a hierarchy of hydrogen production methods based on techno-economics. Figure 9 presents this hierarchy and explains the drivers/constraints associated with each technology option, with some indications to how this might change under a different set of assumptions.

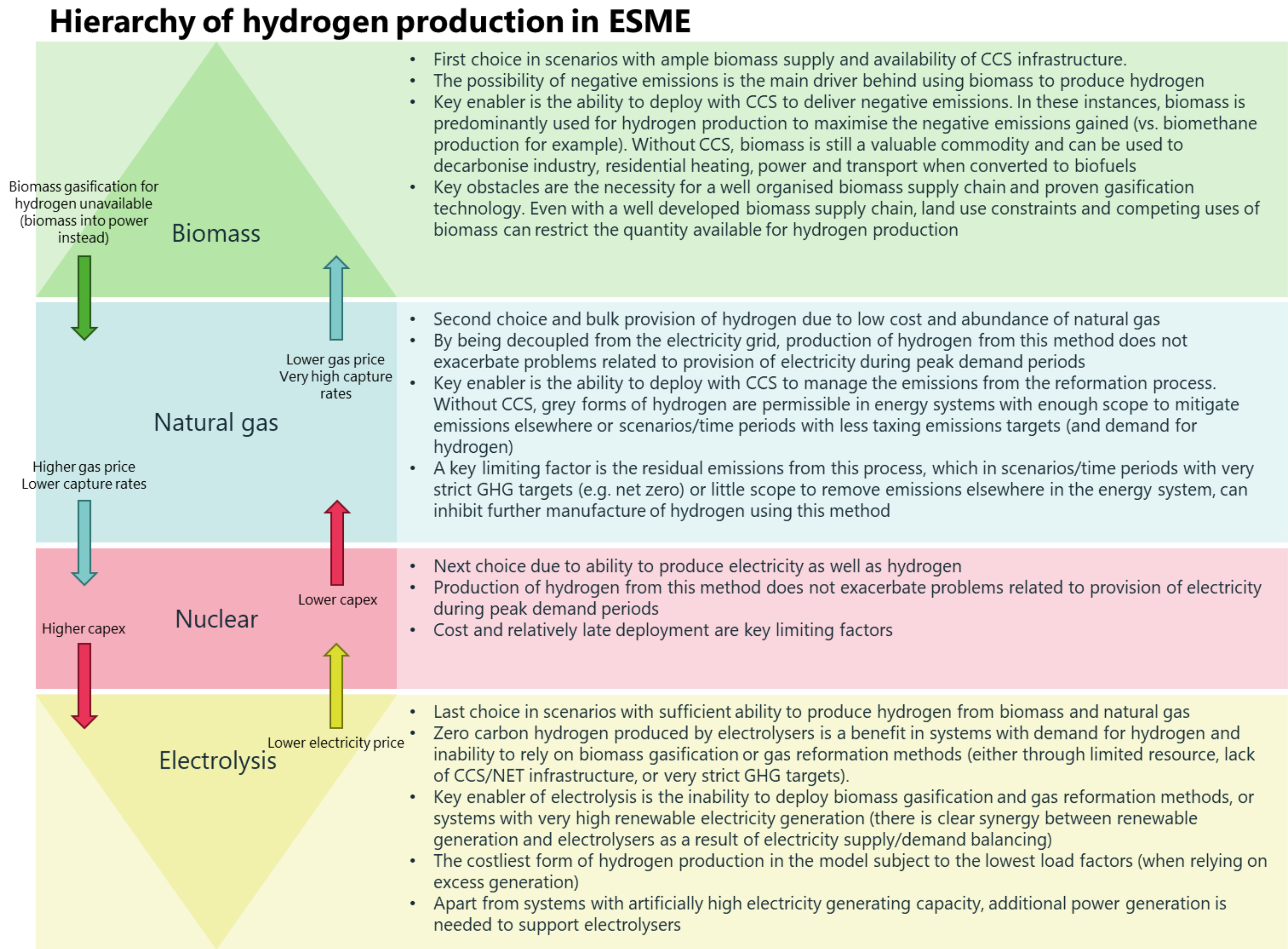

Figure 9: Hierarchy of hydrogen production methods in ESME

[4] Defined as tangible costs associated with capital expenditure, operation and maintenance and resource costs.

Across all three scenarios Wales can satisfy its own hydrogen demand from indigenous production, in all modelled years (Figure 10). By the mid-2030s however, Wales becomes a net exporter to other parts of the UK in all scenarios, partly driven by natural gas imports from Milford Haven. Higher hydrogen demand in both the BAL and HYD scenarios prompts even greater production in 2030, as well as higher levels of export throughout the pathways.

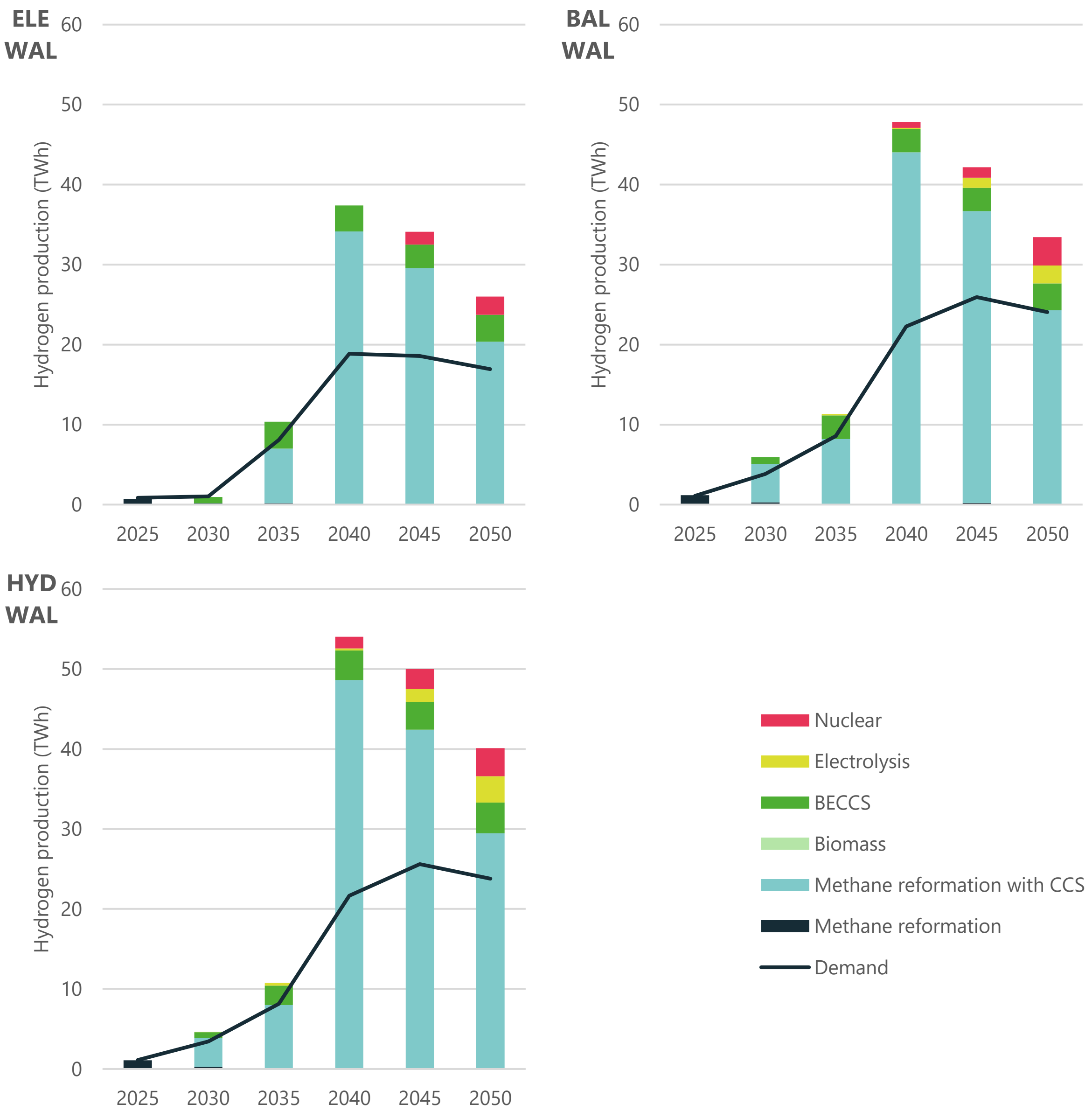

Figure 10: Hydrogen production in Wales for ELE, BAL and HYD scenarios. Welsh hydrogen demand is shown by the black line

In all three scenarios the bulk production of hydrogen is undertaken by methane reformation with CCS (i.e., "blue hydrogen"). This reflects the cost advantage of blue hydrogen that the model sees. Of course, the balance between blue and green hydrogen production, as well as the overall use of hydrogen, is heavily driven by the cost of natural gas. This work was undertaken with natural gas resource cost assumptions at the levels in line with those seen prior to recent geopolitical and global natural gas price events. The period over which recent price rises may be experienced will be at the mercy of several hard to predict (and model) drivers.

Biomass gasification with CCS is also an important method of hydrogen production for Wales and its production goes on to account for most biomass consumption[5]. BECCS hydrogen plants deliver negative emissions which are highly valuable in reaching Net Zero, as they create headroom for other harder to decarbonise sectors (see Table 6 for further explanation). Importantly for system flexibility these plants also offer a flexible, dispatchable, and seasonably storable zero carbon energy vector which can, and is, used across the energy system.

In each of the scenarios there is a noticeable downward trend in hydrogen production from 2040 onwards. This is likely driven by the capture rates of blue hydrogen production being <100%. As the carbon constraint on the system continues to tighten towards 2050, the emissions not captured in the blue hydrogen production process need to be reduced – we therefore see a reduction in hydrogen production, driven by the reduction in blue hydrogen.

Running counter to the reduction in blue hydrogen is the increase in hydrogen production from advanced nuclear reactors and electrolysis. Advanced nuclear reactors supply two very important zero-carbon energy vectors, electricity and hydrogen. By 2045, in the ELE scenario, we begin to see hydrogen production from this technology emerge. In the BAL and HYD scenarios this happens five years earlier, likely due to the need to meet the higher levels of hydrogen demand from a zero-carbon source.

The BAL and HYD scenarios, with higher demands for hydrogen to meet heating loads, see meaningful electrolyser capacity installed and operating out to 2050. These begin being deployed in 2040 with scale up production through to 2050. Their presence indicates a system which needs hydrogen but cannot increase output from the existing technology mix in ELE due to the tightening emissions constraints and uncaptured carbon from blue hydrogen; and the system has no more biomass available to use in gasification plants and cannot substantially increase output from nuclear plants.

[5] The other main use of biomass is in industry.

6.2.3. HYDROGEN CONSUMPTION IN WALES

Hydrogen is a versatile and flexible energy vector that is used in all parts of the energy system in all scenarios. The main consuming sectors for hydrogen are industry, heating and, later in the pathway, shipping (Figure 11).

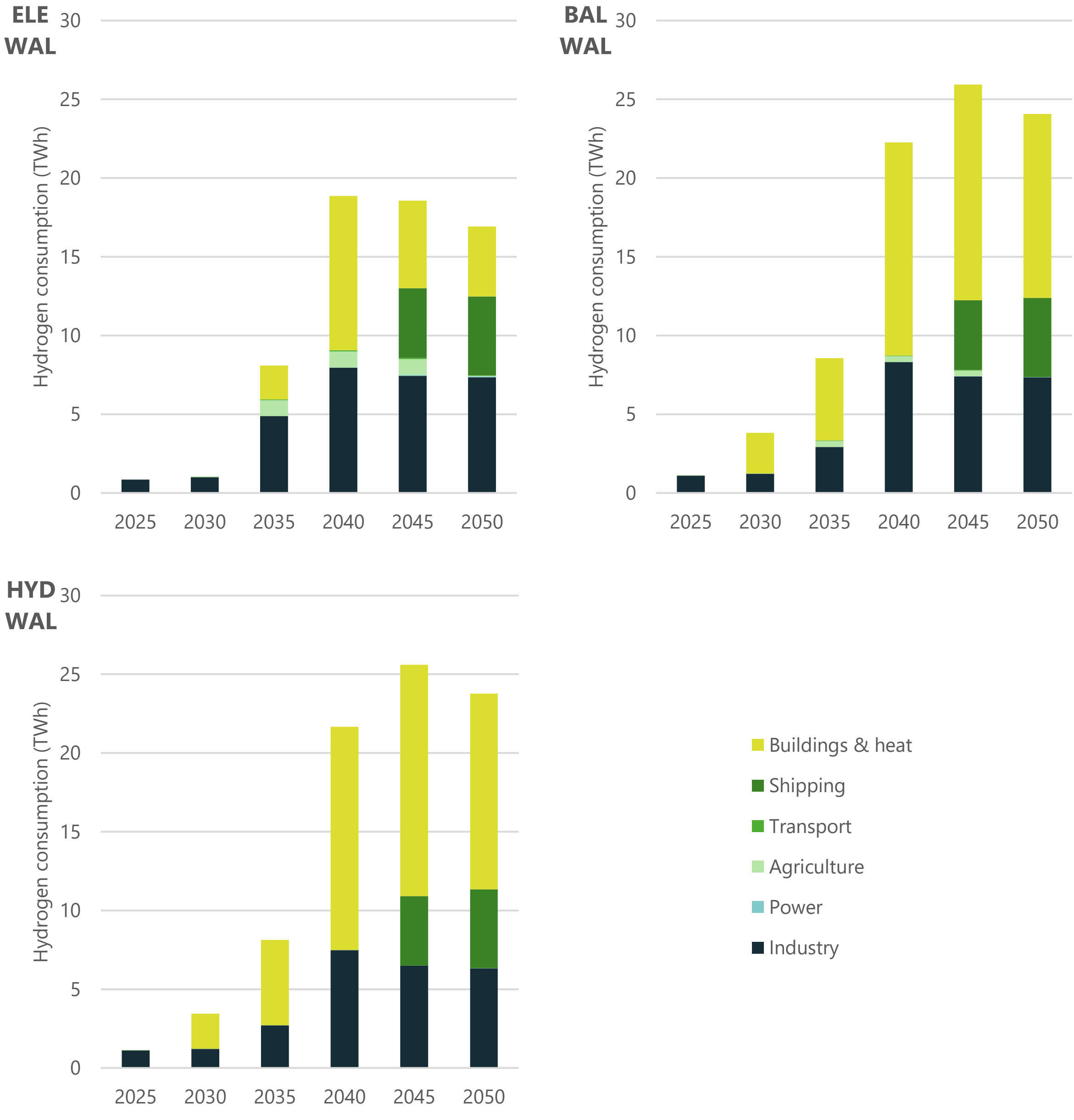

Figure 11: Hydrogen consumption in Wales in ELE, BAL and HYD scenarios

The difference in overall hydrogen consumption between the three scenarios is largely driven by the amount consumed in buildings and heating. Industry is the earliest user of hydrogen with around 1TWh/yr. being consumed in the mid-2020s and 2030s. By 2035, industrial demand for hydrogen increases in tandem with the ability to produce large quantities of blue hydrogen through methane reformation with CCS. It should be noted, that whilst we take a techno-economic view in the modelling, Wales is characterised by a handful of large industrial energy consumers (e.g., steel and refineries) – therefore, a small number of individual decisions, potentially not necessarily based on a whole system decision making (i.e., not internalising all external system costs), are likely to drive the level of industrial demand for hydrogen.

6.2.4. INDUSTRIAL CONSUMPTION OF HYDROGEN IN WALES

Industrial energy demand in ESME refers to energy consumed by the main sectors of industry:

- Iron and steel
- Chemicals
- Metal products and machines
- Food, drink and tobacco
- Paper, printing and publishing
- Cement, ceramics and glass
- Refineries
- Other (includes industries such as textiles and rubber/plastic products)

Hydrogen use in industry displaces the use of liquid fuels and natural gas. In ELE, industry remains the single largest consumer of hydrogen throughout the pathway, largely due to the much lower volume of hydrogen used in buildings and heat. The amount of hydrogen consumed in industry is relatively consistent across the scenarios, but with a gradual decline from 2040 as supply is diverted to other sectors (i.e., shipping, agriculture, and heating) (Figure 12). Industry responds with an increase in natural gas and biomass consumption both in combination with CCS. Industry continues to rely on natural gas because of the input assumptions feeding the model (see 6.1.2). Details on which industrial sectors continue to use natural gas are provided in section 7.2.2.

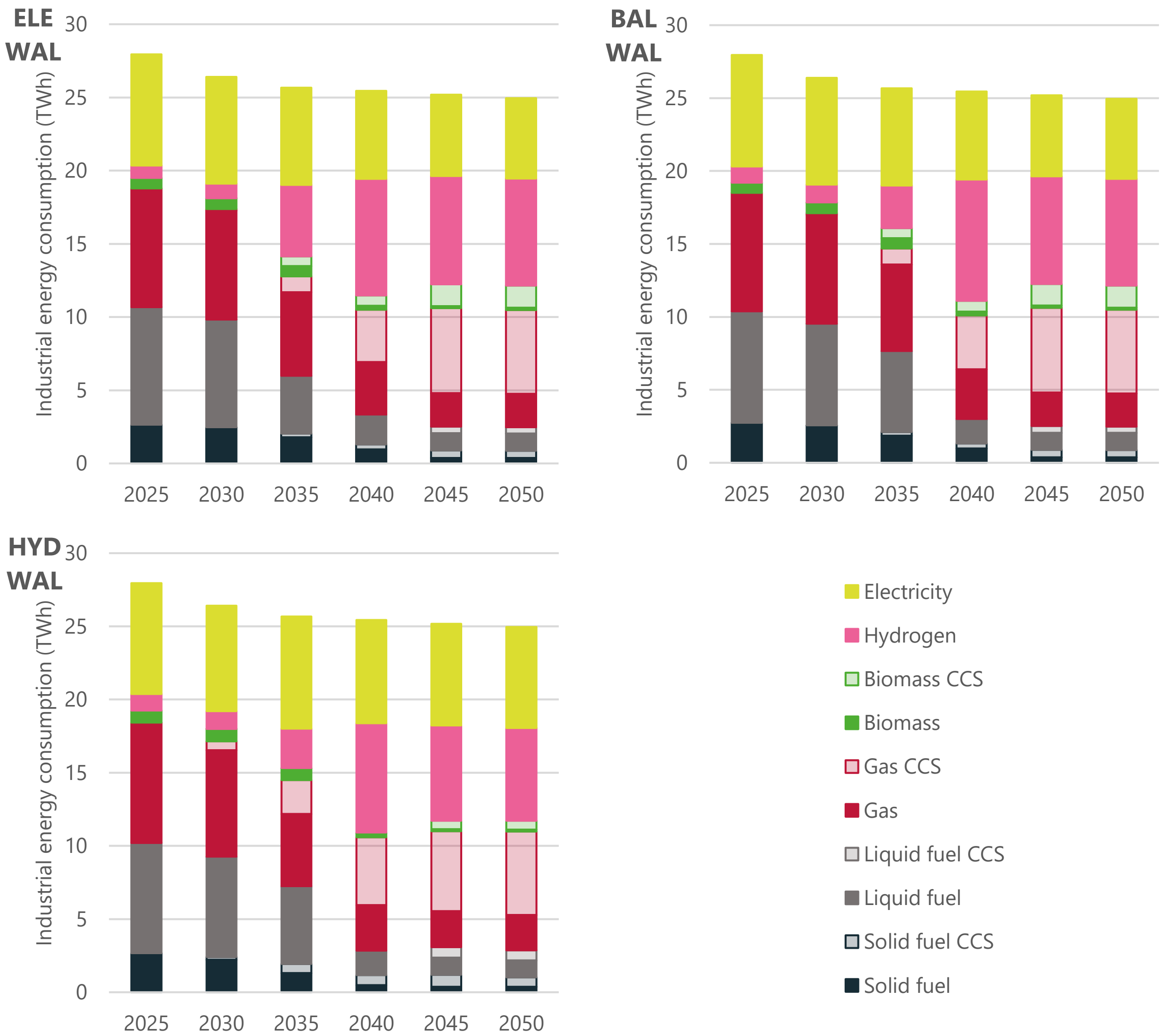

Figure 12: Industrial energy consumption broken down by energy vector in ELE, BAL and HYD scenarios. Light shaded areas correspond to consumption of energy vector with CCS

Likewise, once ammonia/hydrogen-fuelled ships are developed, and operational from 2045, all scenarios choose to divert hydrogen supplies to this end use since it represents the only option for maritime decarbonisation. Other currently speculative technologies may emerge in time, but at present alternative options do not exist.

6.2.5. RESIDENTIAL CONSUMPTION OF HYDROGEN IN WALES

The amount of hydrogen used in residential heating is largely dependent on the uptake rates of electric forms of heating in existing homes and how these are combined with hydrogen boilers. In ELE, the amount of hydrogen consumed for heating is lower than in BAL and HYD because of high installation rates of heat pumps, and a higher utilisation of the heat pump within any hybrid hydrogen-heat pump systems. In the ELE scenario, hydrogen is used to support electric heating during peak periods, when meeting heating loads with only electricity would require much more significant electricity grid reinforcement and installation of generation capacity.

In BAL and HYD, heat pump uptake is reflective of barriers to accelerated uptake due to consumer preferences, lack of confidence in the technology, and/or no supporting mechanisms to encourage uptake through market incentives or government policies. Furthermore, district heat is restricted to high density urban areas, which represent the lowest cost networks. This results in system designs with greater hydrogen boiler uptake for heating. In these scenarios, hydrogen boilers are used much in the same way gas boilers are used today to supply baseload and meet peak heat demands. There are some dedicated electric heat pump systems, but hydrogen boilers will also form part of a hybrid heat pump systems as in ELE. Relying solely on hydrogen boilers for heating results in increased consumption of hydrogen in BAL and HYD.

6.2.6. GAS CONSUMPTION IN WALES

In the 2020s and 30s, natural gas is used in industry (discussed above in 6.1.2) and to supply heat to homes (Figure 13).

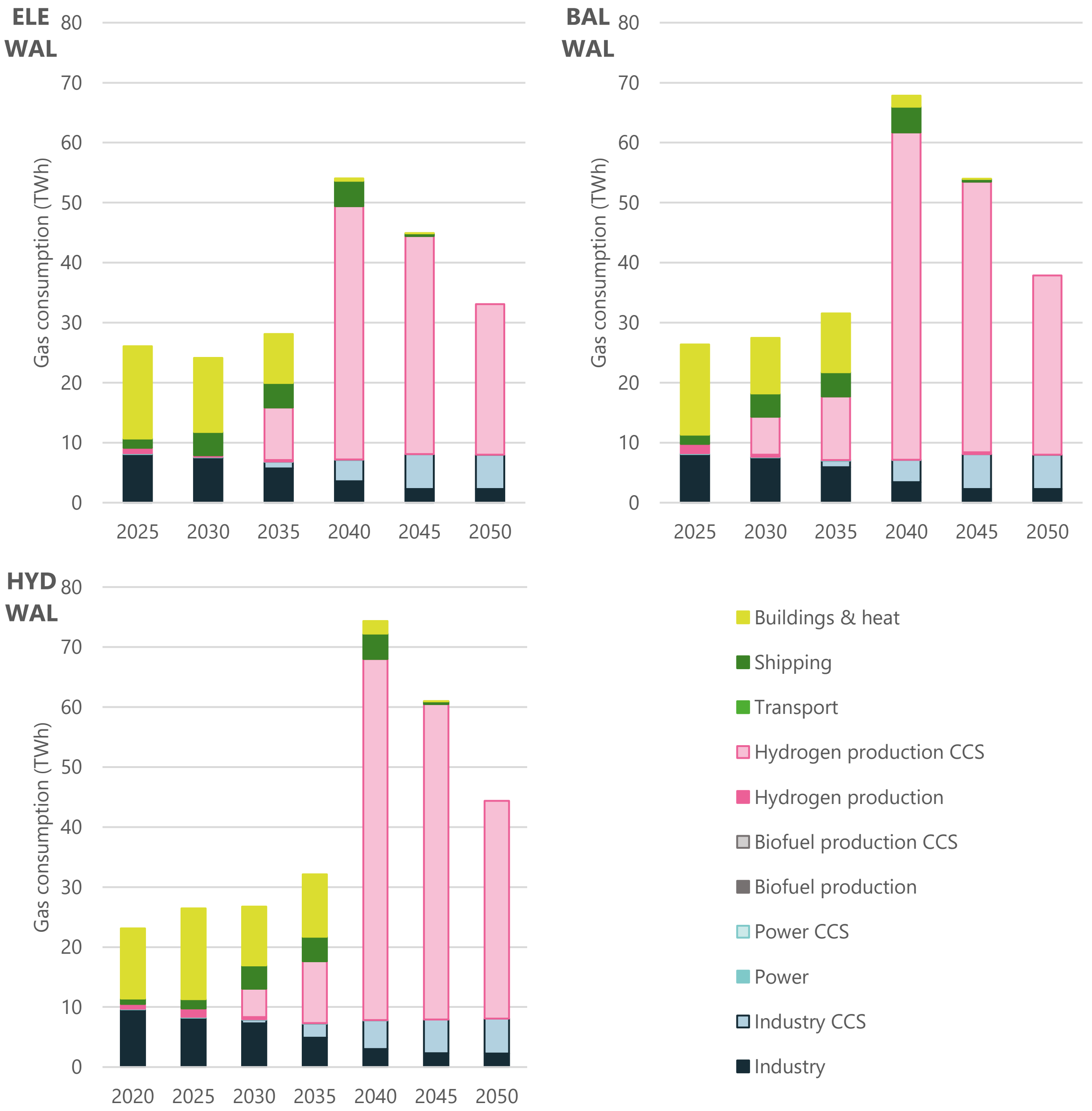

Figure 13: Gas consumption in Wales for ELE, BAL and HYD scenarios. Light shaded areas correspond to consumption of energy vector with CCS

The amount of gas used in industry is relatively consistent for each pathway but from the mid-2030s, continued natural gas use is permissible only in conjunction with CCS. Gas used in the provision of heat to residential and commercial buildings decreases from mid-2020s as more homes rely on electric and hydrogen-based heating systems. Natural gas is no longer used for residential heating from 2045.

Decreases in gas consumption for heating are offset by an increase in natural gas used to produce hydrogen. From 2040, all scenarios see a surge in gas consumption for this purpose, highest in BAL and HYD which have the greater demands for hydrogen. From this 2040 peak, natural gas consumption for hydrogen production begins to decrease. This is driven by two things: firstly, the CO_2 targets becoming stricter as they approach Net Zero by 2050 (at this point zero carbon forms of production such as electrolysis and advanced nuclear processes are necessary); secondly, investments in improvements in efficiency in both building fabric and hydrogen-fuelled technologies reduce the overall demand.

6.2.7. RESIDENTIAL AND COMMERCIAL HEAT SUPPLY IN WALES

Residential and commercial heating in Wales fully decarbonises by 2045 in all three scenarios as buildings shift away from fossil fuel-based heating. Three sources of low carbon energy vectors provide heat to buildings: electricity, hydrogen and district heat (Figure 14)[6].

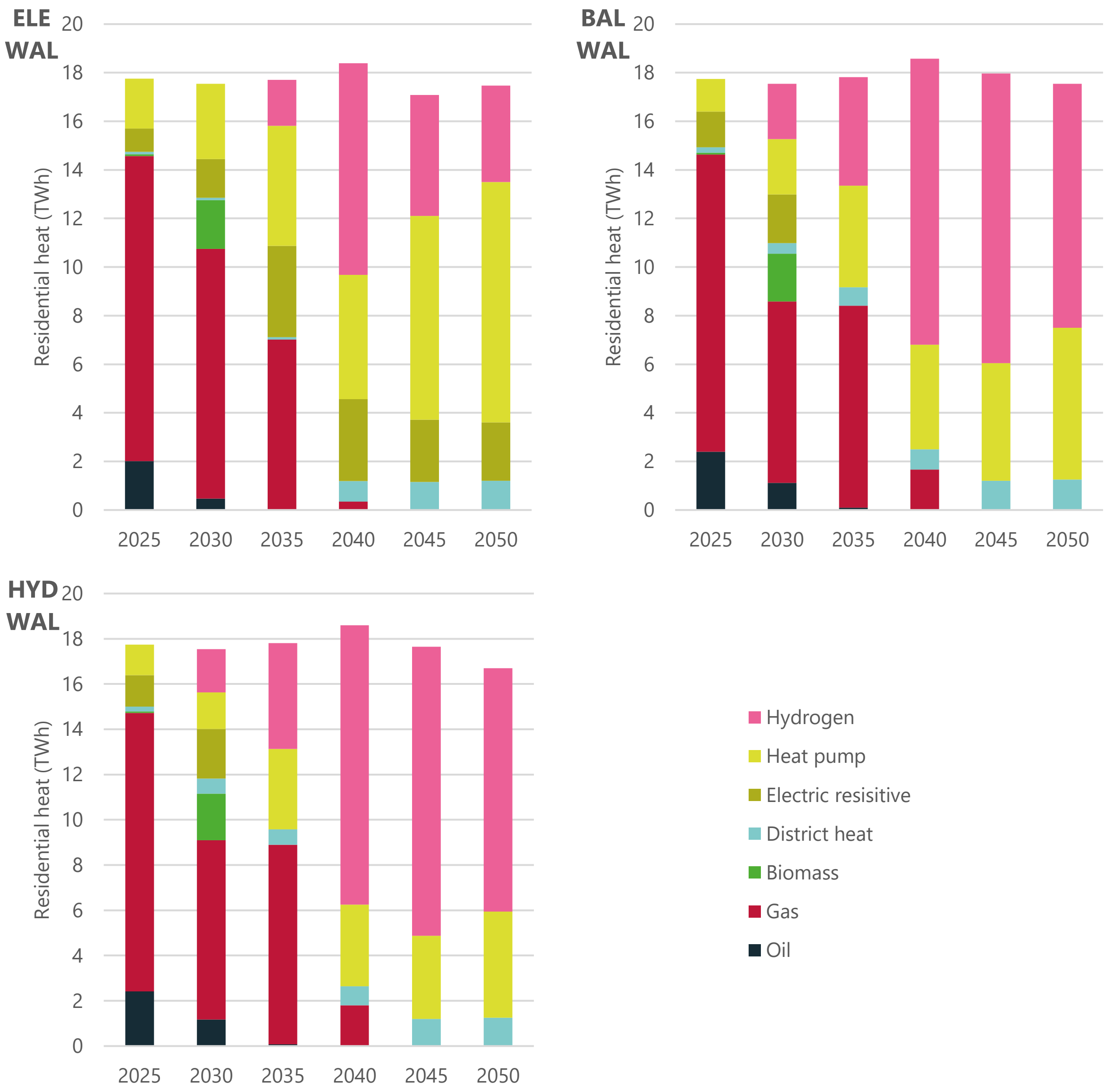

Figure 14: Residential and commercial (non-industrial) heat supply in Wales broken down by energy vector for ELE, BAL and HYD scenarios

In these scenarios, district heat networks (DHNs) are constrained to only be rolled out in high density urban areas, where heat losses and costs are lowest. BAL and HYD see similar amounts of district heat supplying buildings but, with higher rates of heat pump installation (compared to BAL and HYD), ELE delays most of the DHN rollout until 2040 relying instead on electrified heating.

[6] Presence of biomass boiler is to help to meet the 6th Carbon Budget, in reality this may be a modelling artefact and wider concerns (e.g., air quality might challenge this).

The split between electric and hydrogen heat supply is entirely driven by the assumed installation rates of electric-based heating in all of the scenarios, and the way in which hydrogen boilers are used (i.e. like gas boilers are today or as part of a hybrid HP system).

The ELE scenario has high installation rates associated with heat pumps and can also install new electric resistance heaters too. The modelling approach can also optimise deployment and operation of hydrogen boilers, subject to the scenario constraints described earlier, but any capacity deployed must be utilised in a way consistent with either hybrid or load-following operation. In the ELE scenario, most of the heat in buildings is supplied by electricity, with hydrogen boilers playing a supporting role during winter. This has two advantages when exploring least cost Net Zero system designs:

1. Heat pump (and other electric heating systems) can be sized for baseload and higher demand heat provision rather than the peak demand, which is assumed to be a 1-in-20-year winter (i.e., peak happens infrequently). This keeps the overall size smaller and therefore less costly. Furthermore, it avoids additional grid reinforcement/generating capacity needed to meet peak heat demand with electricity.
2. Hydrogen can be reserved for the coldest periods rather than being used to meet all heat demand throughout the year (this helps to manage the situation where heat storage is insufficient at times when electricity is in short supply). This reduces the amount of hydrogen that needs to be produced (Figure 11) thus saving on production costs (including capital cost of production plant and resource costs associated with natural gas reforming). Seasonal storage of hydrogen also avoids sizing hydrogen production for peak demand periods.

Hydrogen boilers are an important feature of the ELE scenario with 14GW total boiler capacity installed in SWE by 2050, the same as in HYD. However, the volume of hydrogen being consumed by boilers in ELE is lower compared to the other scenarios because many are operating as part of a hybrid HP system.

In BAL and HYD, heat pump installation rates are much less, reflecting a situation where people are unable or unwilling to adopt heat pumps. Old electric resistive heating systems are also not replaced with new ones. Hydrogen boilers are assumed to be operated in much the same way as gas boilers are today (i.e., they are used to meet all heating demand, termed “load-following”).

As a result, hydrogen provides the bulk of the heat in buildings from 2040 in these two scenarios. The implications on the gas network are that the transmission network needs to be substantially developed to move higher volumes of hydrogen around the country, including use of seasonal stores. Hydrogen boiler roll-out occurs five years earlier than ELE too with first deployment occurring in early 2030’s. Whilst the majority of hydrogen boilers in BAL and HYD are dedicated boiler systems (i.e. not hybrids), boilers can still be operated as part of a hybrid HP system in these scenarios. Given the two advantages of hybridisation as seen by a least cost optimisation model like ESME (described above), it is likely that some of these boilers are paired with heat pumps in a hybrid system. In these systems, boilers would not be load-following but instead would see more operation during peak demand periods. Therefore, BAL and HYD will include a mix of dedicated hydrogen boiler systems and hybrid HPs.

6.2.8. DECARBONISATION PATHWAYS FOR SOUTH-WEST ENGLAND

Decarbonisation in South-West England (SWE) is achieved in the same way as in Wales: through the adoption of low and zero carbon technologies in the main energy system sectors; and through negative emissions generated by bioenergy with carbon capture and storage (BECCS) and in the land use sector (e.g., by afforestation). Figure 15Figure 8 shows the rate of decarbonisation occurring in each of the main sectors in SWE and the extent of negative emissions generated by BECCS used in hydrogen production. Table 7 provides a summary of the decarbonisation options in each of the sectors with key differences between the scenarios drawn out.

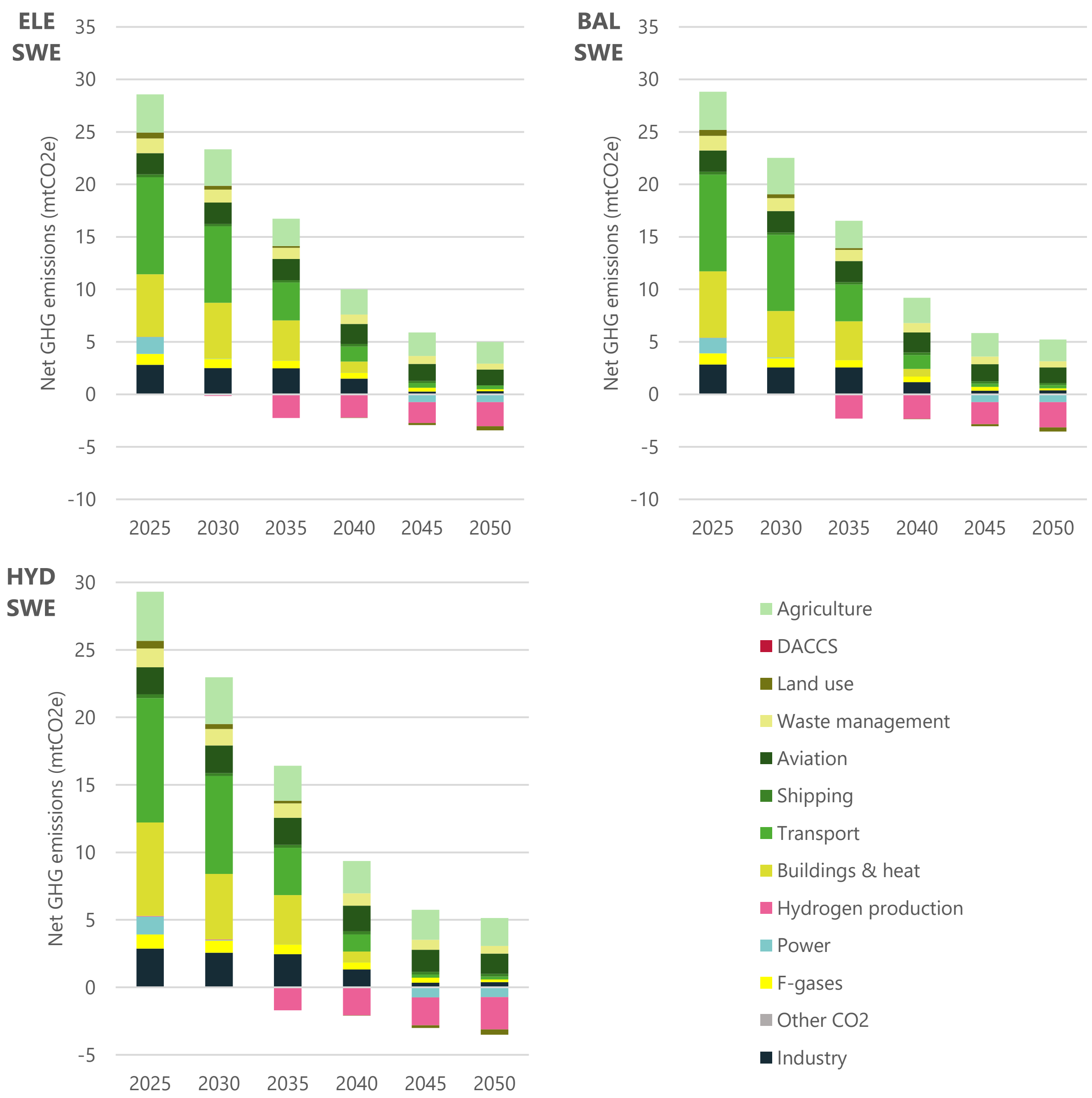

Figure 15: Net GHG emissions in South-West England from 2025-2050 for ELE, BAL and HYD scenarios

Table 7: Summary of decarbonisation in South-West England by sector

Sector	Description
Power	The power sector decarbonises quickest becoming net zero by 2030 in all scenarios and becomes net negative in 2045. Early decarbonisation is largely driven by reduced output from CCGTs, which cease to supply baseload electricity from mid-2020s, and an increase in nuclear generation. In all three scenarios, SWE generates most of its electricity from generation III nuclear plant. This starts with Hinkley Point C (3.2GW by 2030) but increases to roughly 4.5GW by 2050. Electricity production in SWE is not quite enough to meet regional demand, so some imports from other parts of the UK are necessary. With so much generation from nuclear power, there is not much need for dispatchable generation in the form of hydrogen turbines of CCGTs with CCS. Renewable capacity in the form of solar photovoltaics retires entirely by 2040 and is not replaced.
Heating	Residential heat decarbonises next reaching net zero in 2045 in all three scenarios. This is caused by a shift from natural gas as the dominant supplier of residential heat to a combination of three main zero carbon energy vectors: electricity, hydrogen and district heat.
Transport	Transport sector is next to decarbonise with the 2030 national ban on new ICE sales applied to all scenarios. A small number of plug-in hybrid vehicles remain to 2050, which maintain a demand for liquid fossil fuels, hence road transport never reaches net zero in the 2050 timeframe. Residual emissions remain in aviation.
Industry	Industrial emissions decrease steadily to 2040 after which there is a sharp decrease. This is a result of a big switch to hydrogen from liquid fuel and natural gas seen in all three scenarios. Industrial CCS is also critical to ensure emissions from industry are eliminated.
Negative emissions	Negative emissions are delivered by BECCS for hydrogen production as well as some from land use as a result of afforestation (note that afforestation is a hard-coded assumption and does not change between the scenarios). Negative emissions create headroom for other areas of the energy system to continue to emit GHGs. This is particularly important for difficult or costly parts of the system to decarbonise such as aviation, industry and agriculture. Negative emissions are the reason why a net zero energy system is still possible with residual fossil fuel use in parts of the system. Despite producing negative emissions, South-West England remains a net emitter of GHG throughout the UK. This is a result of ESME optimising energy system design to deliver a net zero UK, which could entail some regions being net negative and some being positive emitters. This output does not seek to make suggestions about GHG policy or targets in SWE, it is simply an outcome of these particular scenarios.

6.2.9. HYDROGEN PRODUCTION IN SOUTH-WEST ENGLAND

Hydrogen production methods in SWE are the same as in Wales and are driven by the same decision factors outlined in 6.2.2. In terms of quantity, demand for hydrogen in SWE is relatively similar to Wales especially from 2040 onwards. However, in contrast to Wales, SWE production volume is lower than demand from 2040 (Figure 16). Therefore, SWE is reliant on hydrogen imports from other parts of the UK including Wales.

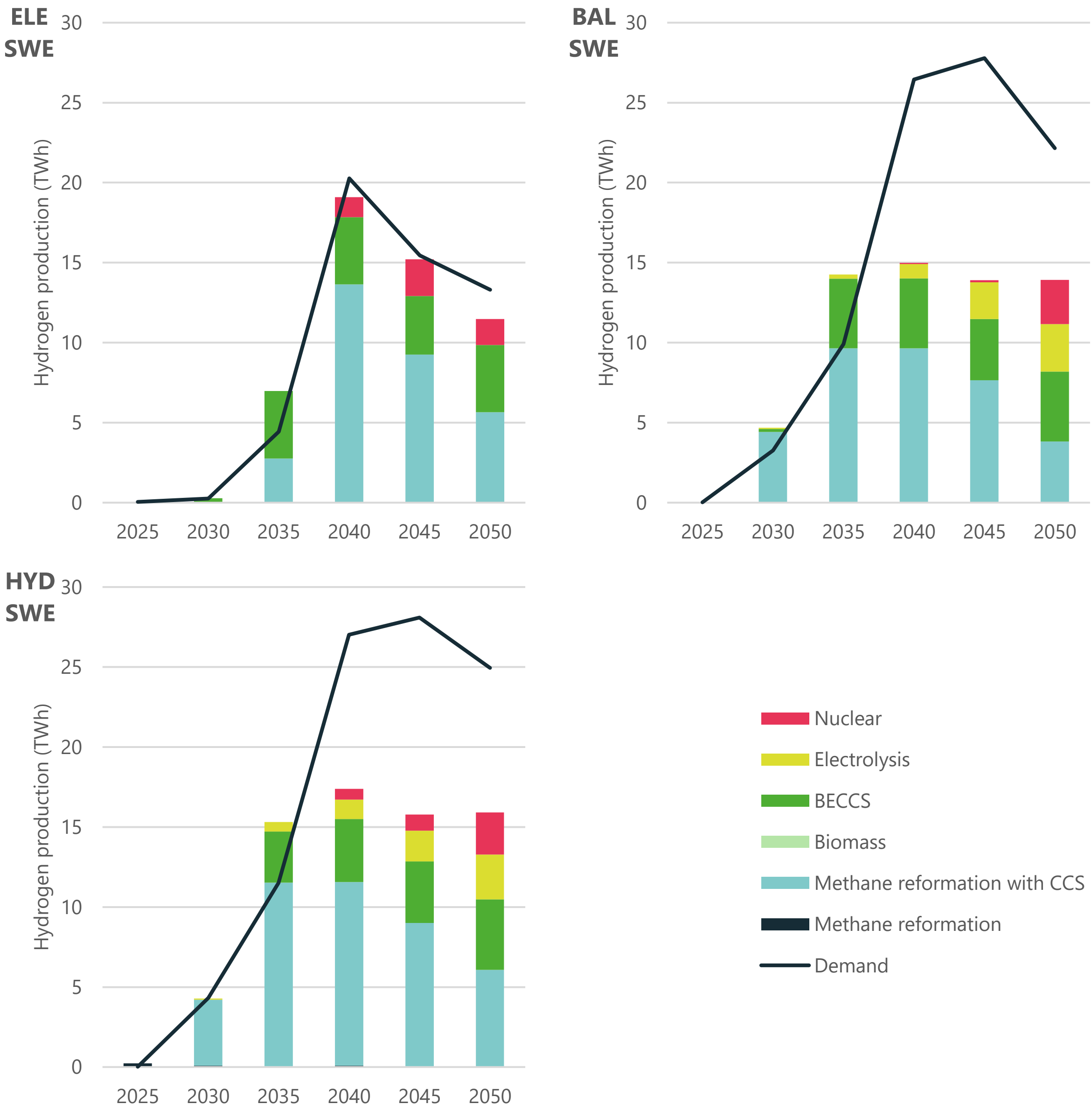

Figure 16: Hydrogen production in SWE for ELE, BAL and HYD scenarios. SWE hydrogen demand is shown by the black line

Methane reformation with CCS is the main method of production in SWE in all scenarios. Biomass gasification with CCS is also an important production method because of the ability to deliver negative emissions. It is the main use of biomass from 2035.

Electrolysis features in BAL and HYD because of higher hydrogen demand for use in residential heating. These electrolysers are supplied by electricity generated by nuclear power in the region and imports from other parts of the UK. As stated above, to maximise the cost-effectiveness of electrolysers in a model like ESME, the load factor should be kept as high as possible which means running them consistently throughout the year rather than relying just on periods of excess renewable generation.

6.2.10. HYDROGEN CONSUMPTION IN SOUTH-WEST ENGLAND

The volume of hydrogen consumed in SWE is similar to in Wales, but where it is used differs completely. SWE has a far lower industrial energy demand compared to Wales, but a much higher residential heating demand. This is reflected in the hydrogen consumption charts (Figure 17), which show residential heating to be the highest consumer of hydrogen in SWE across all three scenarios.

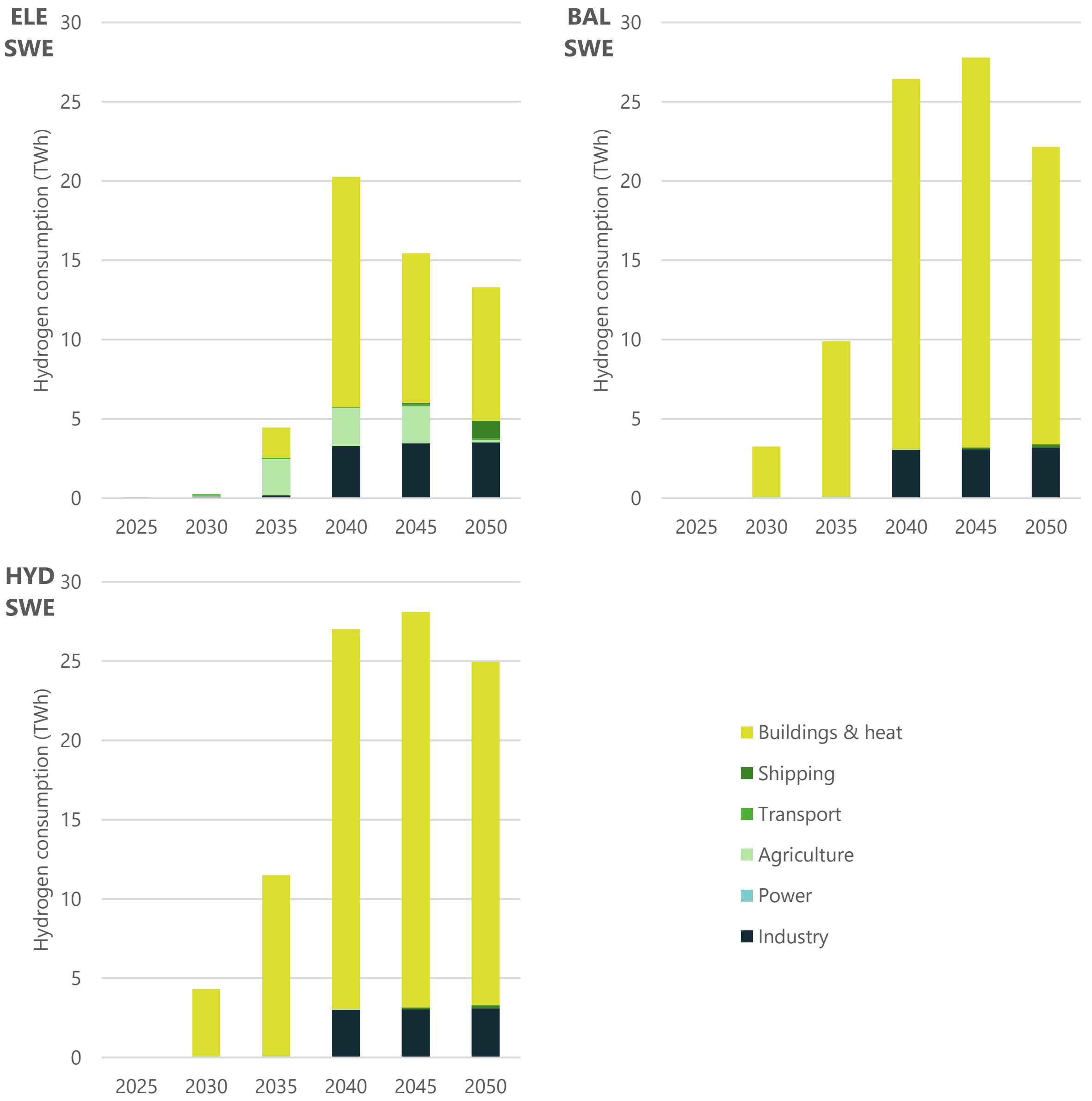

Figure 17: Hydrogen consumption in SWE in ELE, BAL and HYD scenarios

Hydrogen consumption in industry is consistent across the scenarios, with a hydrogen switch happening in 2040 displacing liquid fuel and natural gas use (Figure 18). Overall consumption of hydrogen is lowest in ELE due to a much greater uptake of electric heating. Another key difference in where hydrogen is used in ELE vs. the other two scenarios is in agricultural machinery. By 2050, hydrogen-fuelled agricultural machines that have reached the end of their life are replaced with electric ones. Hydrogen is then used to decarbonise shipping in the region. The difference between hydrogen consumption in SWE in BAL and HYD are slight, with HYD consuming between 0.5-2TWh/yr. more than BAL in each of the modelled years.

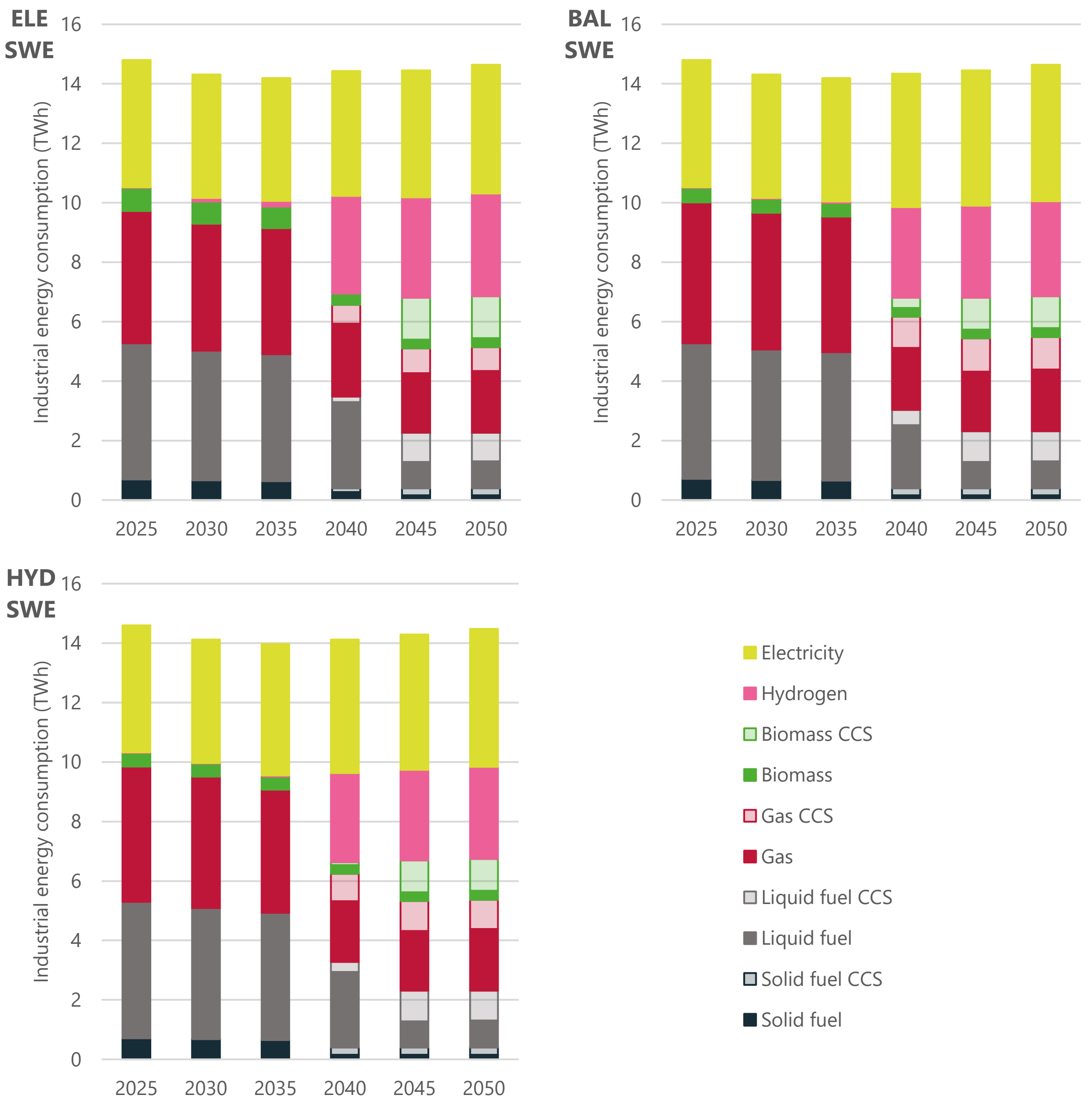

Figure 18: SWE industrial energy consumption broken down by energy vector in ELE, BAL and HYD scenarios. Light shaded areas correspond to consumption of energy vector with CCS

6.2.11. GAS CONSUMPTION IN SOUTH-WEST ENGLAND

In the 2020s and 30s, natural gas consumption in SWE is predominantly to meet heat demand in residential buildings (Figure 19). This decreases over the pathway as homes move away from gas boilers to other forms of heating. By the mid-2040s, all scenarios see a complete shift away from natural gas for home heating.

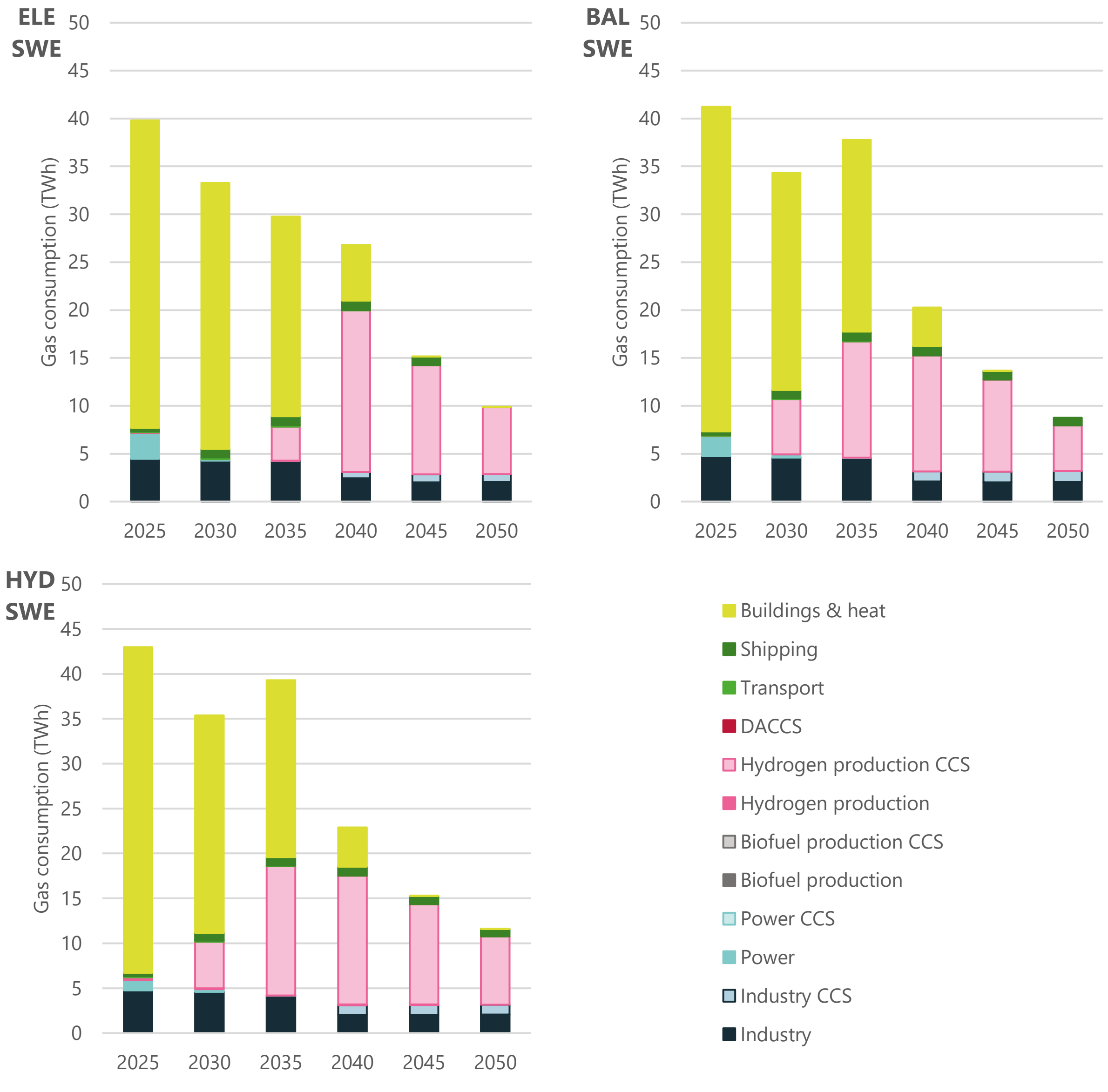

Figure 19: Gas consumption in SWE for ELE, BAL and HYD scenarios. Light shaded areas correspond to consumption of energy vector with CCS

Natural consumption in South-West of England decreases over time, primarily driven by the aforementioned shift away from gas heating in homes. There is also a decrease in the amount of gas consumed by industry from 2020s to 2050 as industry switches to electricity and hydrogen. From the 2030s, gas consumption used in hydrogen production increases. This consumption peaks around 2040 and then begins to decline. This decline coincides with improved efficiency in technologies that consume hydrogen, thus reducing demand for hydrogen overall, and also with increased deployment of alternative hydrogen production methods (e.g., advanced nuclear plants and electrolysis).

6.2.12. RESIDENTIAL AND COMMERCIAL HEAT SUPPLY IN SOUTH-WEST ENGLAND

The SWE heating sector is larger than the Welsh heating sector but there is a similar trend in how heat is supplied to domestic and non-domestic buildings: By 2045, in all scenarios, buildings in SWE are being heated by zero carbon (at point of use) sources, either electricity, hydrogen or district heat (Figure 20)[7].

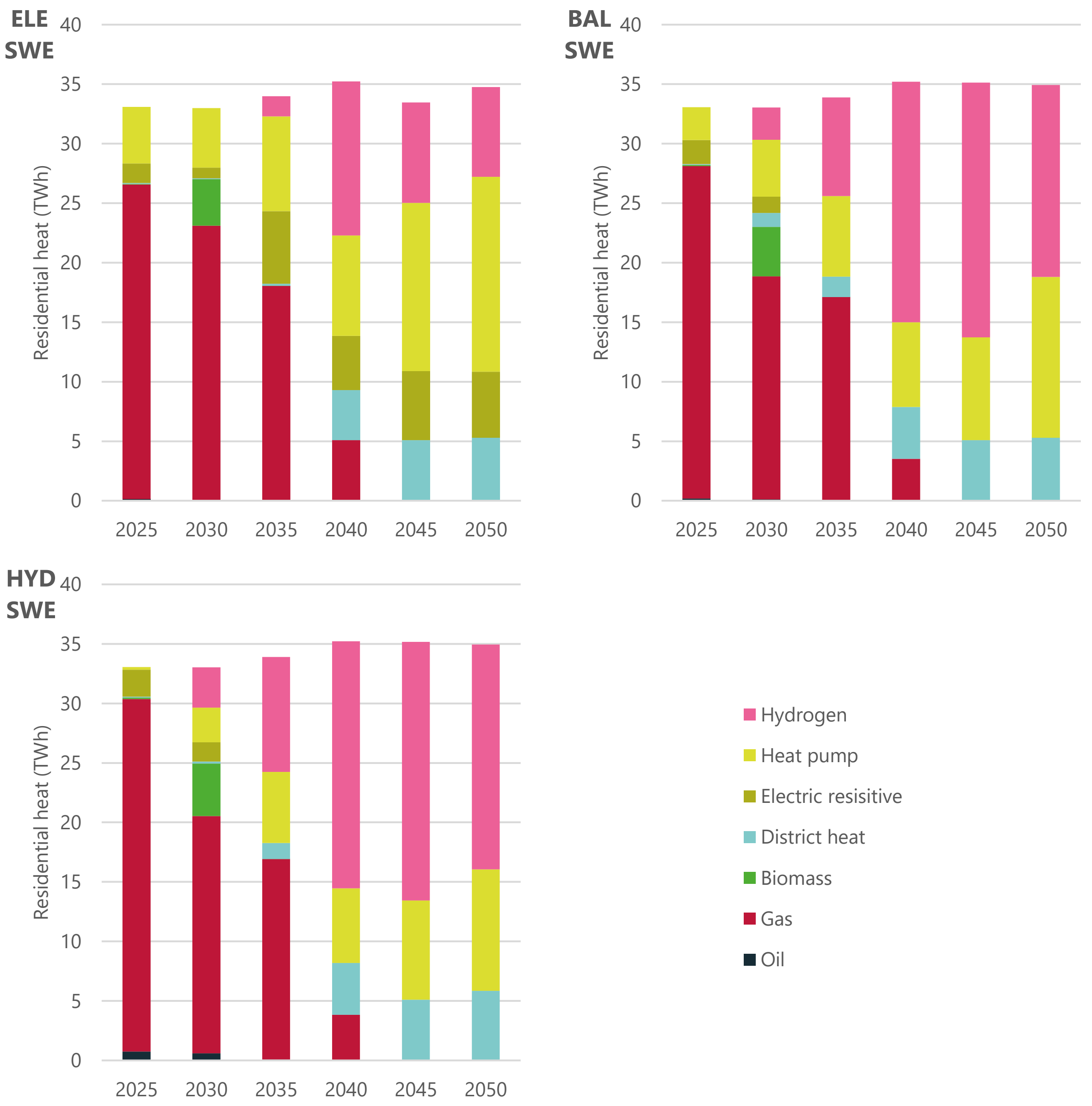

Figure 20: Residential and commercial (non-industrial) heat supply in SWE broken down by energy vector for ELE, BAL and HYD scenarios

SWE is subject to the same constraints on DHN rollout as Wales – the same constraint was applied across the whole UK (i.e., only the lowest cost networks were rolled out). In the ELE scenario, connection to these DHN in SWE does not occur until 2040. This happens sooner in BAL and HYD

[7] Presence of biomass boiler is to help to meet the 6th Carbon Budget, in reality this may be a modelling artefact and wider concerns e.g. air quality might challenge this.

which connect in 2030 and 2035 respectively. High rates of heat pump uptake in ELE mean connection to DHN is not necessary in the early time periods but is important in the later time periods when there is a switch away from gas boilers driven by UK carbon targets. With slower uptake of heat pumps in BAL and HYD, DHN connection happens sooner; however, in HYD, there are a small number of oil boilers remaining until 2030 as a result of low heat pump uptake rates.

As described above for Wales, hydrogen boiler rollout is influenced heavily by the assumed uptake rate of heat pumps, as well as the assumed profile of operation (i.e., load-following or as part of a hybrid system). In ELE, many of the hydrogen boilers will be part of hybrid heat pump systems, supporting heat pump operation during the winter. In BAL and HYD, hydrogen boilers are used to provide heat throughout the year (as gas boilers are today).

6.2.13. INSIGHTS

The role of gaseous fuels in power generation is dependent on the extent to which renewable energy generation is deployed

Power sector decarbonisation in Wales and SWE happens at roughly the same rate, becoming Net Zero by 2030. The Welsh power sector is generally characterised by renewable generation from on and offshore wind, whilst the SWE sees far more reliance on nuclear generation. The power sector in Wales therefore requires dispatchable generation in the form of CCGTs and hydrogen turbines. This form of generation is not as important in SWE given the nature of nuclear generation. There is therefore a continuing role for natural gas in power generation in Wales to 2040, albeit moving from a baseload supplier of electricity to ensuring there is enough capacity during cold, low wind and anticyclone periods. Similarly, hydrogen is also important in the Welsh power sector taking over the role of unabated gas plants from 2040 to 2050.

There is a shifting role for natural gas from supplier of heat to hydrogen production

The 2030s sees a substantial increase in the amount of hydrogen produced in Wales and SWE, the majority of which is from methane reformation with CCS. This represents an important change of use of natural gas from being supplied directly to homes for heating, to supplier of baseload hydrogen for use throughout the energy system. The extent to which natural gas is used to supply hydrogen is likely to be sensitive to the global gas price. For example, substantial increases in the price of gas (perhaps because of certain geopolitical events) could well make methane reformation a less competitive form of production compared to alternatives such as electrolysis.

This work was undertaken with natural gas resource cost assumptions at the levels in line with those seen prior to recent geopolitical and global natural gas price events. The period over which recent price rises may be experienced will be at the mercy of several hard to predict (and model) drivers. If high prices are sustained, not only could Government policy change to mitigate impacts, but the decarbonisation pathway may be significantly altered.

Whilst outside of the scope of this project when it was envisaged, the sensitivity of these pathways to continuing and sustained high natural gas prices, could be tested to understand the robustness of the findings and the long-term implications. Other non-techno economic factors (e.g., public perception, UK external security of supply policy) will likely influence the choice between different types of hydrogen production, influence the choice between different types of hydrogen production and the scale and dominance of blue hydrogen found in the modelling. Decisions made by policymakers could also impact costs associated with different hydrogen production methods.

For example, clear policy support for green (or nuclear) hydrogen production could unlock cost savings that make it more competitive with blue hydrogen.

Another important sensitivity is the carbon capture rates of the CCS component applied to methane reformers. In the model, capture rates are assumed to be around 95% but anything less than this would increase emissions from this process and risk making blue hydrogen incompatible with a Net Zero transition.

Electrolysis is an important source of hydrogen in high hydrogen scenarios

In BAL and HYD, additional hydrogen demand is met by electrolysis. In Wales, the installation of electrolysers to produce green hydrogen is accompanied by the deployment of large generation III nuclear plants. Electrolysers in ESME are generally grid-connected (as opposed to being supplied by off-grid renewables). Therefore, to maximise their output (and their cost-effectiveness) it is important to ensure operating hours are high. Hydrogen is used throughout the energy system and needs to be available each day throughout the entire year. Therefore, reliance just on electrolysed hydrogen produced by on/offshore wind would introduce a challenge during anticyclone periods when the output from windfarms is very low. In fact, hydrogen helps to support renewable generators during these periods of low wind output, so it is necessary to ensure that it can be produced during these times (methane reformation, BECCS or nuclear) or stored in sufficient quantities.

Hydrogen boilers and hybrid systems could mitigate against the situation that electric heat pump deployment remains slow or stalls, or they achieve lower operational efficiency than expected – but this will have consequences for hydrogen supply in the UK

Low uptake of heat pumps because of consumer perceptions/preferences and/or a lack of effective policy could mean hydrogen plays a significant role in the supply of heat to homes and businesses (especially is challenges associated with district heat networks cannot be overcome). This will have an impact on the amount of hydrogen Wales, SWE and the UK will need to satisfy this demand.

Domestic production will require continued use of natural gas (although this is likely to be sensitive to gas prices), which will only be compatible with GHG targets if a successful CCS network can be rolled out and if lifecycle emissions are mitigated (e.g., UK production is decarbonised). Alternative methods include biomass gasification, which is yet to be proven, and will also require a CCS network to maximise the benefits deliverable by this production method (i.e., negative emission).

Furthermore, challenges associated with producing sufficient biomass for use in hydrogen production need to be overcome. These include difficulties surrounding land use as well as competing uses of biomass (industry and power generation). Advanced nuclear reactors that can produce both electricity and hydrogen represent another novel technology option. There are examples of these in operation in other parts of the world but more needs to be done in the UK if these are to form part of the energy mix.

Electrolysers are a proven technology but need to be run with a high load factor to make them economical. Therefore, reliance on excess renewable generation as the main source of hydrogen production is unlikely to deliver this. Instead, grid-connected electrolysers (or off-grid systems powered by dedicated renewable generators) might be necessary to deliver large quantities of hydrogen needed by the UK.

This also highlights the importance of zero carbon, baseload electricity generation such as that produced by nuclear reactors. If the UK was unable to meet hydrogen demand from domestic production, it would have to rely on imports from other parts of the world. Given the changing risk associated with the EU/UK external security of supply position this could have consequences for the UK’s energy security and/or the ability of the UK to influence overseas emissions.

7. SUB-REGIONAL ENERGY SYSTEM MODELLING

7.1. MODELLING OVERVIEW

This project uses the outputs from the UK whole system modelling and uses them to understand the implications of the whole energy system pathways, specifically for networks at a higher geographical resolution. The modelling approach takes least cost net zero whole energy system designs from ESME and translates these to form indicative national infrastructure requirements, based upon local characteristics, that allow those energy system designs to be realised.

The two fundamental steps used in this project to provide indicative infrastructure requirements are:

1. Translation of model outputs at regional level to drivers of network change (e.g., disconnections driven by fuel switching) at a more granular level.
2. Working out the consequences for these drivers of change at higher levels of the network, e.g., medium pressure and above. Aggregation of these infrastructure specifications into bills of quantities at local government scale.

The bill of quantities derived from the modelling includes elements that are not typically modelled directly in coarse-grained whole energy system models. These include electricity and gas connections, network abandonment costs and repurposing interventions. The assumptions used in are provided in the assumptions log, published alongside this report.

The modelling approach has two features, important to note for the interpretation of the following analysis. ESME is a least-cost optimisation model. ESME is a whole system rather than network model – it therefore cannot represent detailed network designs. Instead, it uses representative designs from real networks. The ITAM model determines the level of change required to a network to realise the energy system modelled by ESME. However, it is not an optimisation model and the cost of its network designs do not feedback into ESME, for further whole system, least-cost optimisation. Therefore, when assessing the feasibility of each scenario, cost implications require further analysis.

7.2. INTERPRETING THE WHOLE SYSTEM OUTPUTS

Sections 7.2.1 to 0 provide an overview of how the whole system modelling outputs for key sectors have been interpreted and treated in the Infrastructure Transition Analysis Model (ITAM) to underpin the network analysis.

7.2.1. HEATING

Domestic heating disconnections from the gas network are driven by switching to heat pumps and district heat network (DHN) deployment. In all three scenarios there is relatively extensive use of hybrid heating systems in 2050. In these systems the heat pump meets baseload heating requirements and the hydrogen boiler, peaking. They offer significant value to the system by reducing the electricity network reinforcement required to meet peak demands in winter. Subsequently, gaseous infrastructure is largely retained across all three scenarios, serving different volumes, specifics for each region are provided in section 0 to 0 The standalone heat pump and DHN uptake, partly driven by the scenario assumptions, are therefore relatively modest, in all three scenarios.

The total number of properties on DHNs is very similar across three scenarios according to ESME, as expected given the constraints imposed on them. The variation in the number of associated disconnections from the gas grid is almost entirely due to a parameter adjusted in ITAM, which interpolates between a situation where (within a given neighbourhood of a few thousand dwellings) properties on the gas grid are switched to district heating before those which are off the gas grid (leading to more disconnections) and a situation where the priority is reversed (leading to fewer disconnections). The former extreme is used in ELE and the latter in HYD, with the proportion of disconnections in BAL set to the mean of the two extremes.

The number of connections retained to supply hydrogen as a space heating fuel across the whole WWU service area is 2.41 million in ELE, 2.45 million in BAL, and 2.51 million in HYD. These connections supply a mixture of standalone H2 boilers and hybrid H2 boiler/heat pump systems. The model outputs do not give the split between hybrid and standalone systems, but they do suggest that in ELE all hydrogen boilers would be part of a hybrid system. There is some indication of some hybrid deployment in BAL and HYD as well, but the modelling outputs and assumptions for these scenarios taken together point to widespread use of standalone hydrogen boilers.

ESME does not allow new network to be constructed to carry hydrogen, only retrofitting of the existing gas network. This assumption has been carried over into the sub-regional modelling. When combined with the modelled regional heating technology mix, it implies that all properties off-grid in 2020 would be heated electrically by 2050. It seems likely that in a real system with the level of hydrogen heating seen in HYD and BAL there would be an economic case for some extension of the hydrogen distribution network but we have not quantified this.

DHNs are seen in more densely populated areas where heat loss and therefore costs are lower. The Associated gas grid disconnections, therefore, also occur in densely populated areas, where the number of connections to kilometres of gas network is greatest. From a gas network point of view this means that the DHN driven disconnections have proportionally lower impact on the length of the retained gas network, than if DHN uptake were to occur in less densely populated areas.

Because of the prevalence of hybrid systems, rather than standalone heat pumps and DHNs, we see a lower number of disconnections than anticipated, under all three scenarios. This demonstrates the sensitivity of the future gas network to the uncertainties around:

- Heat consumer technology adoption and the policy decisions that support them.
- Location of disconnections and the gas network connection density of those locations.

Where there is greater distinction between the scenarios is in the volume of hydrogen flowing through the gas network in 2050. For Wales hydrogen consumption for buildings and heat in ELE is ~4.5Twh, in BAL ~11.5Twh and in HYD ~12.5Twh. For the South-West of England in ELE this is ~8.5TWh, in BAL just over nearly 19TWh and in HYD just over 21.5TWh[8]. Most of the difference is driven by the operational use of the heating technologies rather than total capacity. So, whilst disconnections remain relatively modest for each scenario, the differences in use patterns vary significantly.

The extent of the hybrid heating systems deployment is high and must also be seen within the limitations of the modelling methodology (see section 5.3 and Appendix C). It may well be sensitive

[8] See Figure 17: Hydrogen consumption in SWE in ELE, BAL and HYD scenarios

to several factors, including consumer choices, supply chain maturity and external security of supply considerations[9], however it highlights the whole system value of peak shaving heat pumps.

There are also some interesting implications here for the way the gas grid may be funded in the future and the incentives that flow through to consumers. ESME and ITAM are policy agnostic. ESME is a least-cost techno-economic model and therefore effectively assumes perfect incentives and perfect decision-making. ITAM is not a least-cost optimisation tool, but rather takes a whole system view of how to satisfy ESME scenarios, from a network perspective.

The impact of different network funding models on incentives, and the distributional impacts are not part of this analysis but will be an important driver of the transition. Under ELE, a broadly similar gas network and therefore network cost would need to be recovered at a higher cost per unit of hydrogen consumed than under the other two scenarios. The implication of this with regards to different scenarios requires further consideration.

7.2.2. INDUSTRY

ESME models industrial fuel switching at the level of industrial sector, process type (e.g., drying and separation), and region (e.g., South-West). For each sector, process and fuel switching option, the model captures information about the amount of consumption by sites which would find the switch uneconomical, by including a certain amount of baseline fuel consumption in the representation of each option's maximal deployment (see section 6.1.2). This can include unabated natural gas consumption. There are also fuel switching options which combine ongoing natural gas consumption with CCS. In addition, in some cases the model chooses not to fully deploy options to switch away from natural gas consumption to meet its overall minimisation goal - CCS or use of negative emissions technologies elsewhere can make this compatible with the net-zero target Exactly which sites would or would not switch is beyond the scope of the model.

With the exception of agriculture, all industrial sectors in the scenarios have some ongoing natural gas consumption in 2050. Some of these sectors (such as 'food, drink, and tobacco') have many small sites dispersed through the gas network, often connected to the low-pressure networks. While it is unknown which sites would switch away from natural gas, there is no reason to assume that sites connected to low-pressure network would find this particularly economical or practical. However, gas network transition studies assume that whole connected areas of low-pressure network can be switched from natural gas to hydrogen. A requirement to maintain natural gas supply for some industrial customers embedded within the low-pressure network could make the transition uneconomic.

Reconciling the limits on industrial fuel switching used in the whole system model, with the assumption that all industrial sites connected to low-pressure networks could switch away from natural gas deserves further study, but for the purposes of the network analysis it is assumed that distributed industrial sectors, with small gas consumers connected to the low-pressure network, can switch away from natural gas completely. These sectors are 'food, drinks, and tobacco' and 'metal products, machinery and equipment'. It is also assumed that the 'cement, ceramics, and lime' sector (which is more concentrated) can be switched entirely from natural gas to hydrogen, as this is broadly in line with the whole system modelling for that sector.

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[9] External security of supply considerations relates to both the provision of natural gas (supply security) as well as the price of gas (price security).

The remaining industrial sectors in the whole system modelling are 'iron, steel and non-ferrous metal', 'chemicals', and 'refined petroleum products', and 'paper, printing, and publishing' – all of which show significant ongoing natural gas demand in 2050 (alongside hydrogen consumption in the case of the first three) across all three scenarios. For these sectors, it is assumed that all large carbon dioxide emitters and/or natural gas consumers continue to consume natural gas[10].

For the network analysis it is assumed most smaller industrial consumers switch to hydrogen, but a number of larger consumers stay with natural gas, in many cases with carbon capture and storage.

7.2.3. NATURAL GAS SUPPLY AND NATIONAL TRANSMISSION SYSTEM

Most of the natural gas supply to the WWU licence area in 2050 is provided by the National Transmission System (NTS). It enters the region from England from the north (near Wrexham), east (near Cheltenham) and south (near Yeovil). In the West, LNG reception terminals at Milford Haven[11] provide an important supply to the NTS. In energy terms, across the three scenarios, these terminals supply between 37 TWh and 41 TWh of natural gas per year in 2050 and are the only direct import in the WWU area. The only natural gas production, as opposed to import, of methane-based gaseous fuel in the WWU area is via Anaerobic Digestion (AD), but the quantities are small compared to the LNG import: in 2050, AD produces around 0.09 TWh per year in Wales and 0.16 TWh per year in the South-West across all three scenarios.

Where natural gas demand is retained on the local distribution network in 2050 (or required during the transition), supply from a natural gas NTS offtake is assumed to be available to meet it. It is also assumed that a hydrogen NTS will be available, which will run along roughly the same routes as the existing gas NTS. Hydrogen and natural gas LTS requirements are discussed in sections 0 to 0.

[10] This is not based on an assessment of individual sites, some of which may well be able to switch away from natural gas entirely.
[11] Milford Haven is capable of providing up to 25% of total UK demand.

7.2.4. HYDROGEN PRODUCTION AND SUPPLY

The outputs of the whole system modelling provide the total hydrogen production capacity for each scenario for Wales and the South-West of England[12]. For each hydrogen production technology, these regional totals have been distributed between several sites deemed suitable for the technology.

This was a manual process undertaken with WWU and Costain, and not a model output. The criteria for assessing the suitability of the production sites included proximity to, existing energy infrastructure; natural gas supply for blue hydrogen production; industrial demands; population centres; sites with existing nuclear licences; and port facilities, where required for CCS. For each technology, each suitable site in Wales or South-West was allocated a proportion of the capacity for their respective region.

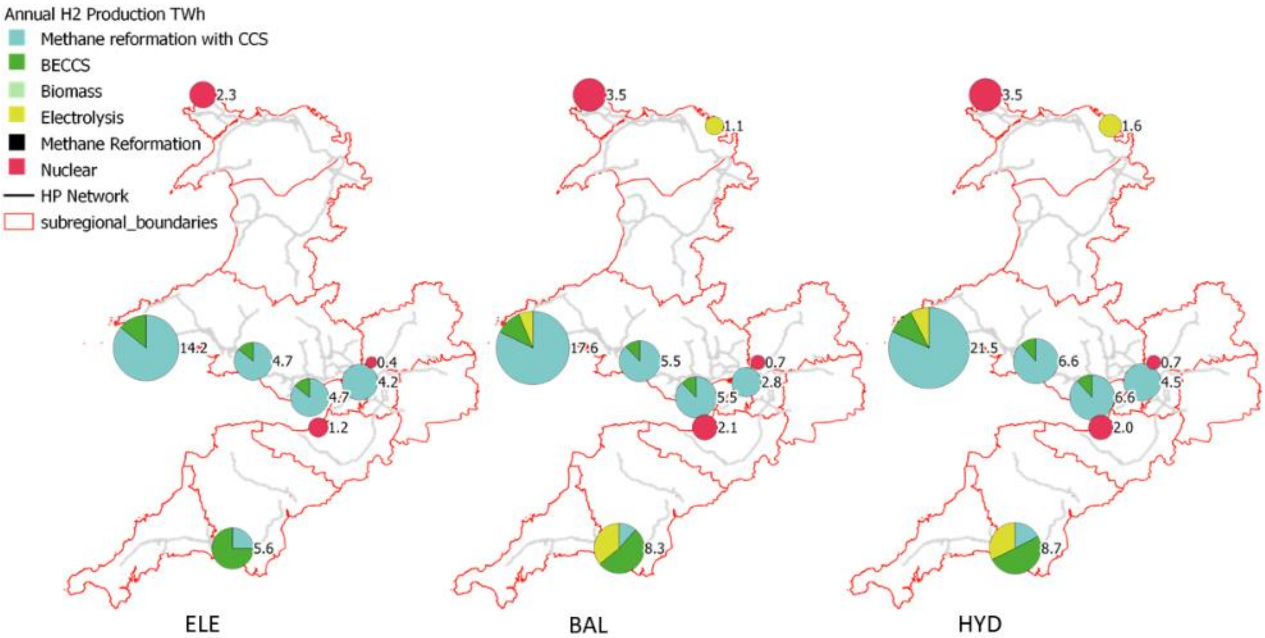

Figure 21: Hydrogen production capacity by indicative site, 2050.

7.3. BILL OF QUANTITIES METHODOLOGICAL APPROACH

This section describes how we translated changes in demand and supply of gaseous fuel into a “bill of quantities” describing the interventions required to the gas network including repurposing, decommissioning, and construction of new network assets.

7.3.1. CONNECTIONS

As described in section 7.2.1, among those connections used to provide fuel for heating buildings, the main drivers of disconnections in the three scenarios are district heating and heat pumps, with the remaining connections switching to hydrogen. Among industrial connections, the work identified an indicative set of sites which retain natural gas demand in 2050 while other industrial connections switch to hydrogen. The four of the industrial sectors considered to have ongoing natural gas demand in 2050: chemicals, paper mills, and iron, steel, and non-ferrous metals.

[12] The scenarios and capacities for the different technologies are discussed in the sections 6.2.2, 6.2.3, 6.2.9 and 6.2.10.

7.3.2. LOW PRESSURE NETWORK

The reduction in the length of the low-pressure network is also driven by disconnections and has been set such that the percentage reduction in length is the same as the percentage reduction in (non-industrial) connections within the MSOA. This is a reasonable approximation, as cost-effective district heating networks will tend to replace gas in contiguous areas rather than in properties intermingled with those switching to hydrogen.

7.3.3. MEDIUM TO HIGH PRESSURE NETWORK

The quantity and pattern of disconnections means we do not see a reduction in the extent of the network at these levels. The key driver of change here is the need to switch fuels from natural gas to hydrogen for most connections – we have also considered the need to remove or replace 'vintage' high-pressure network by 2050.

Ideally, the natural gas supply would simply be suspended over the whole distribution network at the NTS offtakes or above, the residual natural gas flushed out, and then hydrogen injected. In practice, this is not possible. To fully plan a practical transition would require detailed modelling of natural gas and hydrogen flows, which is beyond the scope of the analysis. Instead, we have focussed on two key practical constraints on the network transition, both of which can require entirely new assets to supply hydrogen.

The first constraint is ongoing demand for natural gas on the distribution network in 2050. The effect is straightforward – parts of the network must be kept on natural gas to meet these needs, and so these parts cannot be repurposed to supply hydrogen by 2050. On this basis, we have identified indicative parts of the existing network as retained on natural gas for ongoing demand[13].

The second constraint is the dominant one in the scenarios – properties switching from natural gas to hydrogen will require at least a safety inspection, if not several adaptations to appliances, by skilled workers. Limits on the size of the workforce and on the time acceptable for a property to be without a fuel supply mean that there is a limit on the number of properties which can be switched in one go. In line with previous studies (H21 Leeds City Gate Team, 2016), we take this limit to be 2,500 (H21 Leeds City Gate Team, 2016). This limit creates a need to build new hydrogen network rather than repurposing existing network and is demonstrated in Figure 22.

A method has been developed to identify points on the network on which, having taken disconnections into account, more than 2,500 connections will completely depend for their natural gas supply during transition. We have used this information to identify parts of the network which will be required for natural gas until the downstream transition is complete, and hence are unable to provide the hydrogen for the downstream transition.

It's important to note that even if fewer than 2,500 connections *completely* depend on a point in the network for natural gas supply, it might be the case that isolating that point would unacceptably reduce the flow of gas to a greater number of connections. Because of this, the method may underestimate the real need for new, rather than repurposed, hydrogen network. This is a key variable for the cost of the transition and is under discussion in the industry.

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[13] it was ensured that the routes always followed decreasing pressure tiers

Assuming new hydrogen network will follow approximately the routes of the existing network, parts of the network identified above and information about the age of the HP network to compute the required new and modified network for transition, as shown Figure 23.

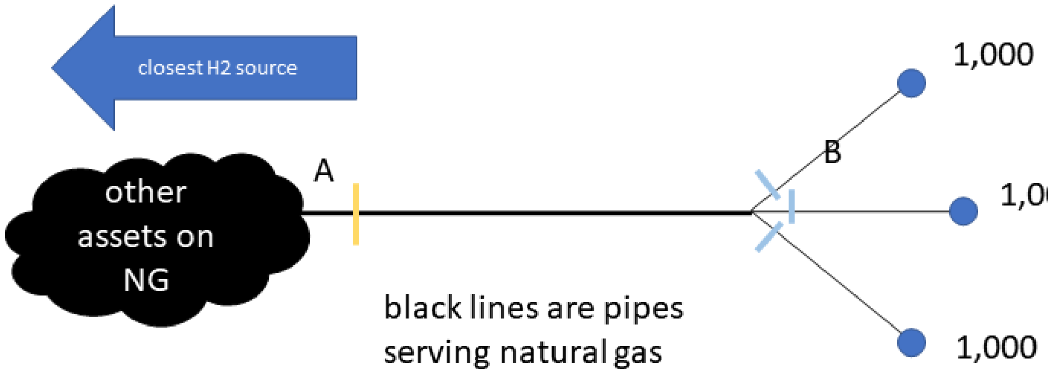


Figure 22: Suppose the blue circles represent separate areas of low-pressure network each with 1,000 connections that want to transition from natural gas to hydrogen. It may be possible to run new hydrogen pipe only down to near point B and then transition each collection of 1,000 connections in turn, using isolation valves at the light blue lines. However, running new hydrogen pipe only to point A and isolating the downstream network for transition there, would mean switching 3,000 connections in one go, which is over the practical threshold of 2,500. So, we need to run new hydrogen pipe to near point B even through after the 3,000 connections have transitioned, the pipe between A and B may no longer be needed for natural gas.

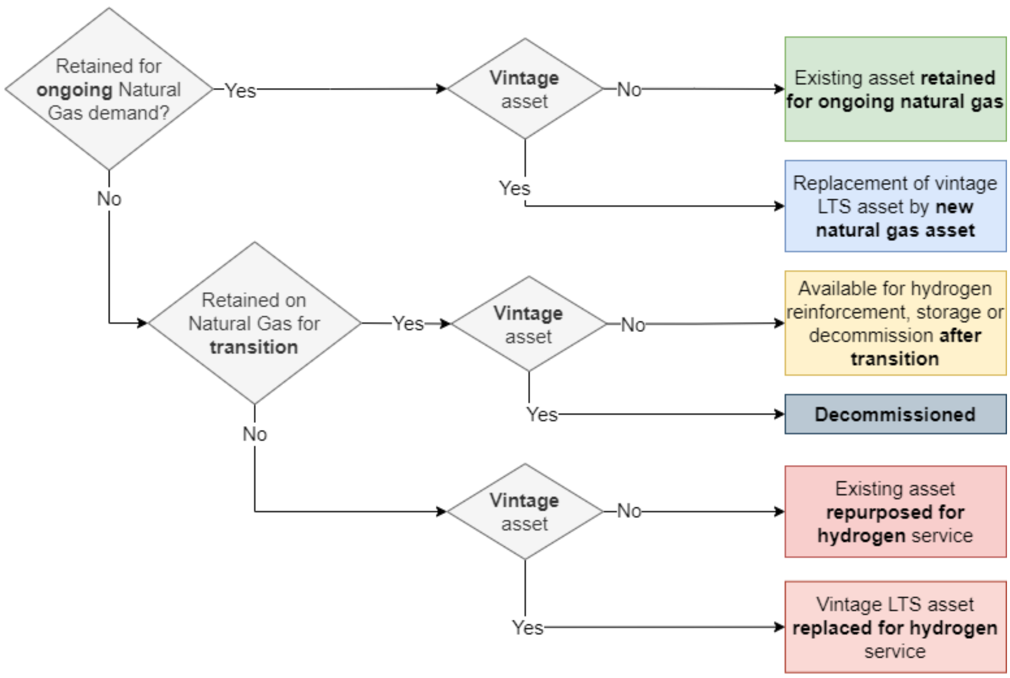


Figure 23: Flow diagram representing the logic used to obtain network changes based on the tagging results

7.4. OVERVIEW OF THE NETWORK CHANGES

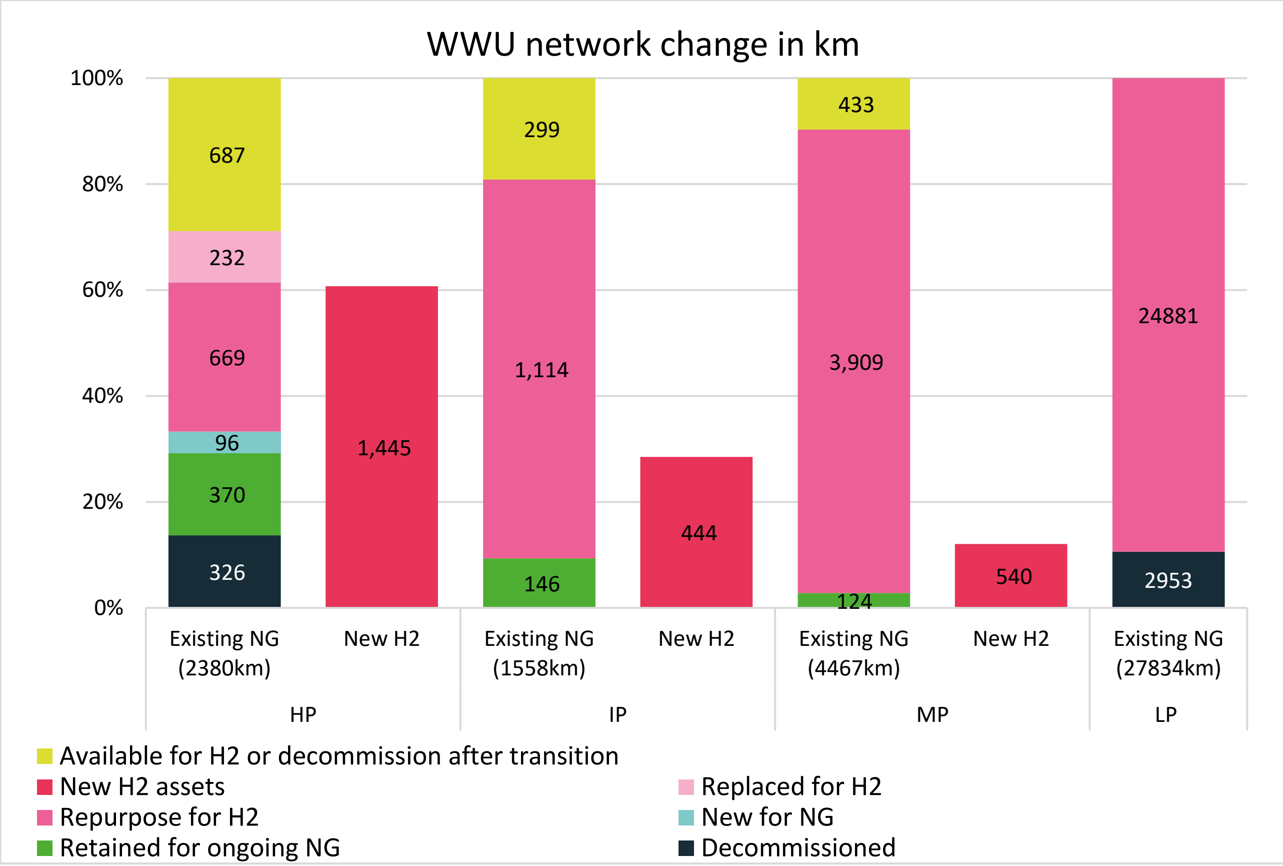
This section provides an overview of the key network changes. The summary of these changes for each of the six sub-regions can be found in section D.

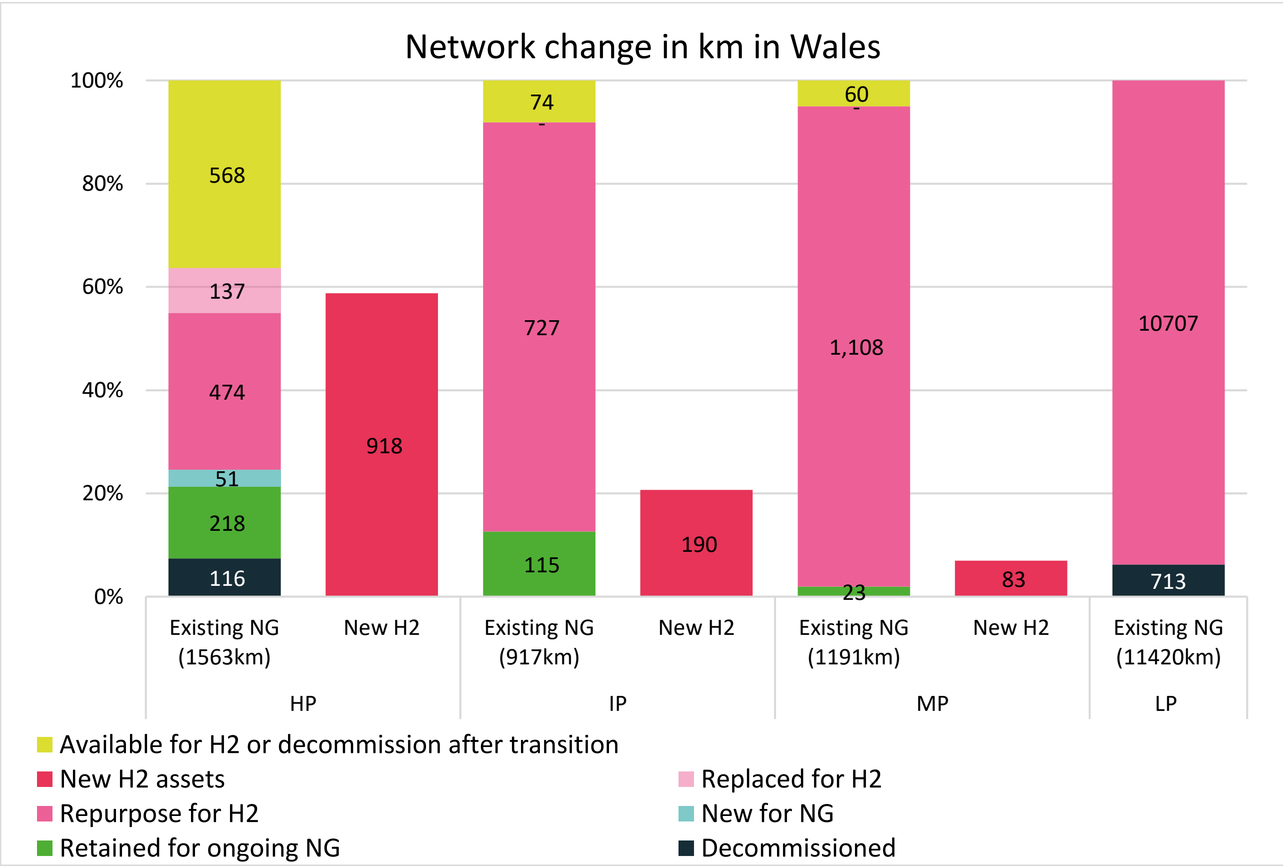
The percentage of non-industrial meters disconnected across the entire WWU network is 11% in HYD, 13% in BAL, and 14% in ELE. There is considerable variation between subregions, which can be largely explained by the variation in the proportion of dwellings in densely built-up areas suitable for district heat. Across all three scenarios, WECA has the highest percentage of disconnections (31-38%) and North Wales has the lowest (2-3%). All three scenarios were used as the basis for subsequent assessment of network infrastructure changes.

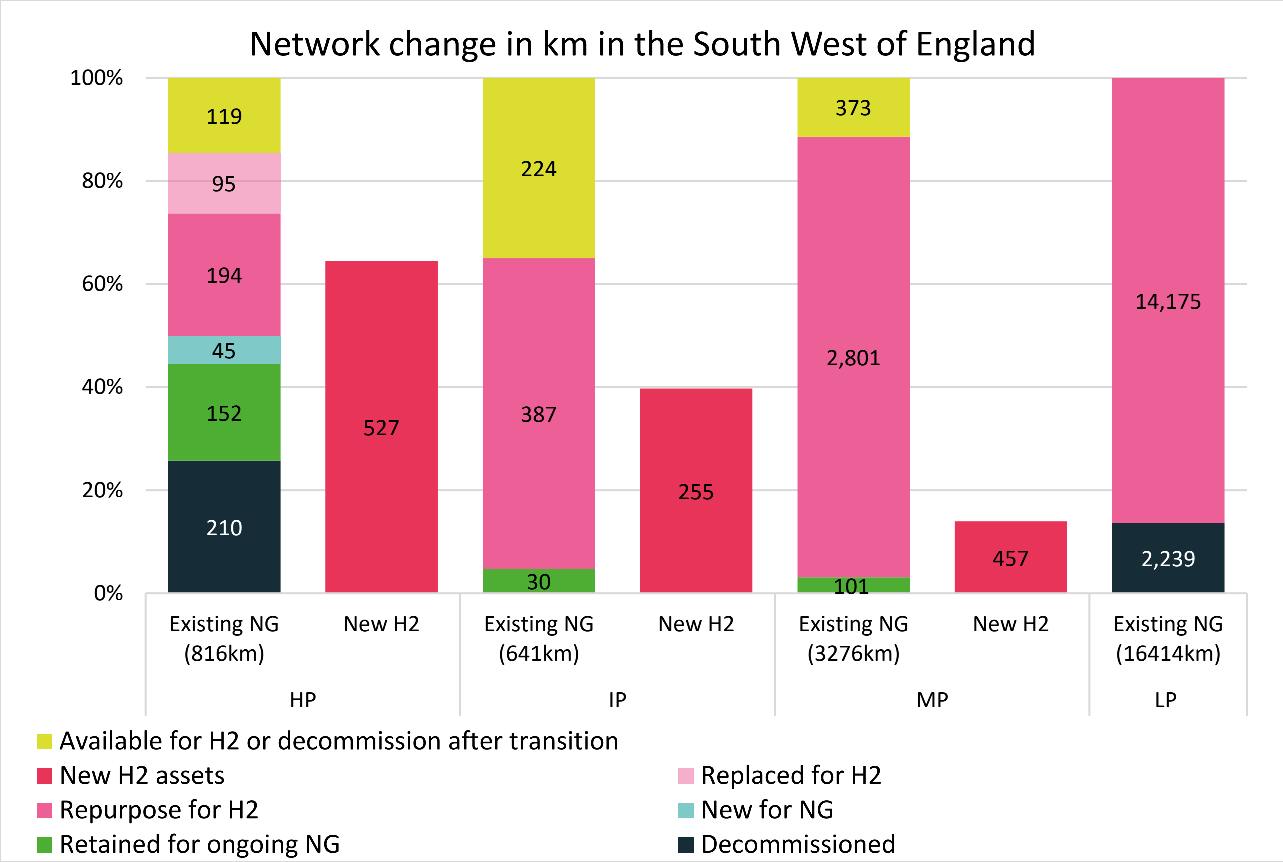
The percentage of low-pressure decommissioned by length is broadly in line with the percentage of disconnections, but tends to be a little lower, as the amount of LP network per connection is relatively low in the neighbourhoods suitable for district heating. As noted in section 5.3, it is likely that a more complete accounting of the costs of hybrid hydrogen boiler heat pump systems would result in more standalone heat-pumps, and this could result in significantly more disconnections.

Because zones with high percentages of disconnections tend to be embedded in large regions of highly interconnected low-pressure network, along with zones that retain more connections, the modelling does not indicate a reduction in extent of the gas supply network at medium pressure and above. The regions with disconnections also tend to be supplied from higher pressure tiers at multiple points, so the higher-pressure network feeding them has low dependency numbers and doesn’t get tagged as “retained for transition” in any scenario. This is consistent with the findings of the H21 work on urban transitions, which indicates that it is generally possible to avoid the need for large amounts of new medium pressure network in urban centres, by taking advantage of redundancy to repurpose the existing network in a piecemeal fashion. Taken together, these observations explain why we see minimal variation between scenarios for the bill of quantities at medium pressure and above.

A striking feature of the constraints which drive the need for new hydrogen network, is that even though the modelled ongoing natural gas demands by themselves would require a significant amount of network to be retained on natural gas, removing these ongoing demands would have little effect on the need for new hydrogen network. This is because the routes retained for ongoing natural gas demand are *also* needed for transitional natural gas demands in a way that still prevents them from substituting for new hydrogen network (as explained in the preceding section).


WWU network change in km
100%
80%
60%
40%
20%
0%
687
232
669
96
370
326
1,445
299
1,114
146
444
433
3,909
124
540
24881
2953
Existing NG (2380km)
New H2
Existing NG (1558km)
New H2
Existing NG (4467km)
New H2
Existing NG (27834km)
HP
IP
MP
LP
Available for H2 or decommission after transition
New H2 assets
Replaced for H2
Repurpose for H2
New for NG
Retained for ongoing NG
Decommissioned


Network change in km in Wales
100%
80%
60%
40%
20%
0%
568
137
474
51
218
116
918
74
727
115
190
60
1,108
23
83
10707
713
Existing NG (1563km)
New H2
Existing NG (917km)
New H2
Existing NG (1191km)
New H2
Existing NG (11420km)
HP
IP
MP
LP
Available for H2 or decommission after transition
New H2 assets
Replaced for H2
Repurpose for H2
New for NG
Retained for ongoing NG
Decommissioned



Network change in km in the South West of England
100%
80%
60%
40%
20%
0%
119
95
194
45
152
210
527
224
387
30
255
373
2,801
101
457
14,175
2,239
Existing NG (816km)
New H2
Existing NG (641km)
New H2
Existing NG (3276km)
New H2
Existing NG (16414km)
HP
IP
MP
LP
Available for H2 or decommission after transition
New H2 assets
Replaced for H2
Repurpose for H2
New for NG
Retained for ongoing NG
Decommissioned

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APPENDIX B – ACKNOWLEDGEMENTS

No.	Interviewee	Organisation *	Specialist area
1	David Joffe	CCC	Whole system
2	Thomas Koller	ENA	ENA work – Gas Goes Green
3	Jon Maddy	University of South Wales	H_2 production and demand
4	Jen Pride, Ron Loveland, Huw Lewis	Welsh Government	Regionalisation (Wales)
5	Chris Clarke	Independent Consultant	Regionalisation (South-West)
6	Tony Parton, Andrew Price	CR Plus	SWIC
7	Tony Green	National Grid	National Grid
8	Angela Needle	Cadent	Other GDNO perspective
9	Peter White	WPD	Electricity DNO perspective
10	Gloria Esposito	Zemo	Transport

APPENDIX C – MODELLING LIMITATIONS

It is challenging to devise a modelling methodology that includes full coverage of the whole energy system but also has sufficient granularity regarding energy infrastructure to inform tangible real-world network decisions, whilst assuring consistency with a low-cost route to Net Zero at UK level.

The approach adopted in the project, using two complementary energy system models and grounding their findings against engineering expertise, overcomes much of this challenge. However, it remains important to understand the remaining limitations. In particular, the idea that the network modelling is derived from ESME pathways requires an understanding of the aims and approaches inherent in the two models.

Hybrid heating systems

Given the important role of hybrid heat-pump/hydrogen boiler systems in keeping homes connected to the gas distribution network in the modelled scenarios, it is important to understand that there is uncertainty around the level of hybrid systems.

ESME distinguishes between a number of building types with different built form and thermal performance, but it doesn't distinguish buildings on the basis of their local infrastructure (e.g., how much headroom is in the local electricity grid).

Within a given spatial node in ESME (for example, Wales) every space heating generating technology contributes to a general "pool" of space heat which can be used to meet demand for space heat of any building of any type. In a very simple scenario with two homes with identical heat demands and two heat technologies – heat pump and hydrogen boiler – ESME may well find it cheaper to meet their combined demand by building a heat pump of capacity C which is operated near its capacity most of the time (high load-factor), and a hydrogen boiler of capacity C which does little except at times of peak demand (low load-factor, than it would to build a heat pump of capacity C which is run to meet the demand of one home, and a hydrogen boiler of capacity C which is run to meet the demand of the other home.

From ESME's point of view, the capital costs of installing the heating systems and any necessary changes to infrastructure would be the same in both situations, but the operational cost would be lower in the first situation (for certain relative fuel costs, at least). Although all space heat is pooled, the first situation can only be interpreted as two hybrid systems, because the heat production profile of either technology *by itself* would not match the heat demand profile of a single home.

If, in a more realistic model of this simple scenario, existing infrastructure supplying the homes was such that the hybrid system avoided the need for reinforcement by cutting peak demand for electricity, say, then it may also beat the non-hybrid system on capital costs., but it could also be the case that the hybrid configuration is more expensive overall: For example, if one home is actually not on the gas grid, then the hybrid configuration would mean connecting it, which may more than cancel the savings in operational costs. It could also be that both homes have a connection to gas grid, but that installing a hybrid in one home (home 'A') is enough to trigger an expensive reinforcement of the electricity network that supplies it, while installing a dedicated heat pump in the other home ('B') would not require any grid reinforcement. In this case, a setup with a hydrogen boiler at A and heat-pump at B could again be cheaper than the hybrid setup, despite the higher operational costs. It may simply be that the additional capital costs of the hybrid systems vs two standalones outweigh the operational savings.

Key methodological elements

Data: ESME is a data-driven model, with projections for demands, technologies and resource being central to its decision making. These projections are, by their nature, uncertain, and results should be assessed carefully in this context. Notably, decisions made in one sector can radically affect the timing or extent of decarbonisation in others.

Linearity: Like many similar models, ESME adopts a linear representation for technology and resource costs, and for constraints affecting the energy system. Such a representation precludes "lumpy investment", where technologies are deployed in blocks of minimum size, and neglects any cost scaling of technologies. This has particular impacts on key sectors, as outlined below.

Spatial resolution: ESME is a multi-regional model, allowing the broad features of transmission and distribution of energy across the UK to be assessed. However, only limited information at finer granularity is integrated. Demand centres are not spatially positioned, and local challenges of transmitting energy within a region are not substantively modelled. Where physical limitations are key (for example, where there are permitted locations for particular power stations), these are implemented as regional constraints within the model. ITAM is required to resolve such limitations whilst remaining as consistent with the ethos of ESME's guiding energy system as possible.

Sector representations: Within ESME each current and future emission point is not modelled independently. Instead, a set of coarse archetypes is used to characterise users of energy and sources of emissions across the whole system. In each case, sector representations are chosen to retain as much operational flexibility as possible, ensuring that innovations in technology properties and control do not impose overly constraining routes. Key examples of these representations are:

- **Heating in buildings**: A small set of building archetypes is used to represent the UK's complex building stock. Within this framework, a simplified methodology is employed where heating supply and demand are pooled and subsequently balanced. This weakens the link between specific building types and heating systems; at single building level not all possible system combinations can be distinguished. The retained flexibility within ESME permits multiple plausible operational interpretations for heating systems – in particular, the operation of gas-fired and heat pump systems across different times of day and seasons regularly hints at hybrid heat pumps as a solution likely to be valuable to the energy system. It should be noted that the heating system costs remain subject to the linearity requirement described above, meaning that there are no additionality effects or cost savings implied for installation of hybrid systems of any type.
- **Industry**: Archetyping of industry in ESME is informed by fuel consumption data provided regularly by BEIS. These data provide a natural disaggregation of industrial fuel use into sectors and end-uses. Within ESME, a set of industrial interventions is available that allows these sectors to transition to low or zero-carbon. As noted above, ESME does not attempt to spatially locate industrial sites within a region and to consider the local infrastructure needs consistent with decarbonisation. Industry differs substantially from sectors such as buildings in that a relatively small number of large emitters contribute much of the UK industrial sector's emissions: as a result, the spatial allocation carried out within ITAM is required to map these emitters to their physical locations before attempting to size the supporting energy infrastructure. Conversely, for smaller industries this allocation is more spatially distributed, and the mapping accommodates this accordingly. Crucially, any retained energy flows within industry must be reconciled with the infrastructure available in the future; a subsequent adjustment within ITAM to reconcile such energy flows with realistic future network

configurations whilst maintaining the ethos passed down by ESME has been adopted in this project. A key observation is that the extent to which industry is assumed to be practically switchable to zero-emission fuels or to utilise carbon capture influences not just the strategic transition envisioned by ESME but also the energy networks built in support of that transition.

- **Energy network infrastructure**: All of the key networked energy carriers – notably electricity, gas and hydrogen – are subject to archetyping within ESME, representing energy at particular voltage or pressure levels. At the transmission level, it is assumed that all barriers to network reinforcement can be overcome with sufficient network investment. For future distribution of low-pressure hydrogen, ESME assumes that local networks can be generated only through repurposing of existing gas distribution networks at a fixed, linear repurposing cost. Network operation and maintenance costs are also assumed to be linear, meaning that additional costs associated with more infrequent flows of gas through the networks are not captured fully. ITAM reconciles this top-down mixture of gas networks offered by ESME with a real-world mapping to pressure tiers and a detailed spatial view of where these repurposed networks might be located, based on an assessment of demand locations and dependencies.

SECTION C: CONCEPTUAL PLAN – COSTAIN

8. CONCEPTUAL PLAN SUMMARY

8.1. SCOPE

Wales & West Utilities (WWU) have been taking initial steps to identify the likely decarbonisation options for their area of operations, with particular focus on the likely future gas network arrangements. However, significantly uncertainty remains around the mix of end-user technologies and decarbonised form of energy supply which will be implemented to reach Net Zero energy system operations. Irrespective of the solutions which are ultimately implemented by end-users, it is anticipated that WWU will need to undertake a major programme of change to support them. In terms of the developed approach for decarbonisation of the UK's gas networks, work has already been undertaken by the Energy Networks Association, including the 'Pathway to Net Zero' and 'Gas Goes Green' to establish credible pathways for UK gas networks at a national level. However, limited work has been undertaken to understand how these high-level pathways translate to regional and sub-regional networks.

The purpose of this project is to address this analytical gap and progress present thinking to the next level: developing a plan to decarbonise the gas networks in Wales and the South West of England which is consistent with the wider UK decarbonisation picture. The overall study scope is comprised of two parts namely production of a Strategic Plan and a Conceptual Plan. The Strategic Plan consists of a decarbonisation roadmap for WWU's entire network, focusing on individual sub-regions and how they link together. The Conceptual Plan illustrates the anticipated gas network end state and describes a feasible transition pathway to achieve it.

This document focuses on the Conceptual Plan. At the regional level, the Conceptual Plan augments the regional outputs derived from the Energy System Modelling detailed in the Strategic Plan with an engineering and technical perspective to develop a gas network plan and assess the potential locations within the region for hydrogen production and likely demand forecasts. The scope includes evaluation of the capacity of the WWU infrastructure required to deliver the volumes of hydrogen to the main demand centres, and development of conceptual network maps for the Local Transmission System (LTS) network for each of the sub-regions at 5-yearly intervals through to production of a perspective of the network in 2050.

8.2. NETWORK DECARBONISATION PATHWAY

Preliminary overarching gas network conversion philosophies which set out gas network decarbonisation plans has been provided in various published documents, such as ENA's Britain's Hydrogen Network Plan and also the UK Government's Industrial Clusters Mission initiative – considering the future gas network configuration and its operations with regards to the provision of security of supply. This publicly available philosophy information has been aligned with available gas network development plans to reach a net-zero end state by 2050 as defined by energy systems modelling scenarios and used to drive the development of the Conceptual Plan. It should also be recognised that these conversion philosophies are at a very early stage in their development. With the work needed to make essential decisions – such as whether we manage the transition from natural gas to 100% hydrogen via parallel transmission pipelines and/or blending and de-blending technology, or how this transition might be rolled out across the UK as a whole – still to be completed.

The remit of the Regional Conceptual Plan work was to augment the WWU scenarios as reported in the Strategic Plan with an engineering and technical perspective for the Wales and South-West of England regions. The purpose of the Regional Conceptual Plan is therefore not to duplicate or provide an alternative parallel perspective, but rather to provide a complimentary and contextualised perspective on a gas network plant for the region – recognising that there are an almost infinite number of permutations in practice with the three scenarios considered in the Strategic Plan providing reasonable coverage of the likely variation.

The approach in developing the underlying Sub-Regional Conceptual Plans has been slightly different. Here the ESC sub-regional modelling outputs have been used as a basis for the engineering and technical assessment work which has been performed to directly inform the development of sub-regional pathways and end-state conceptual designs.

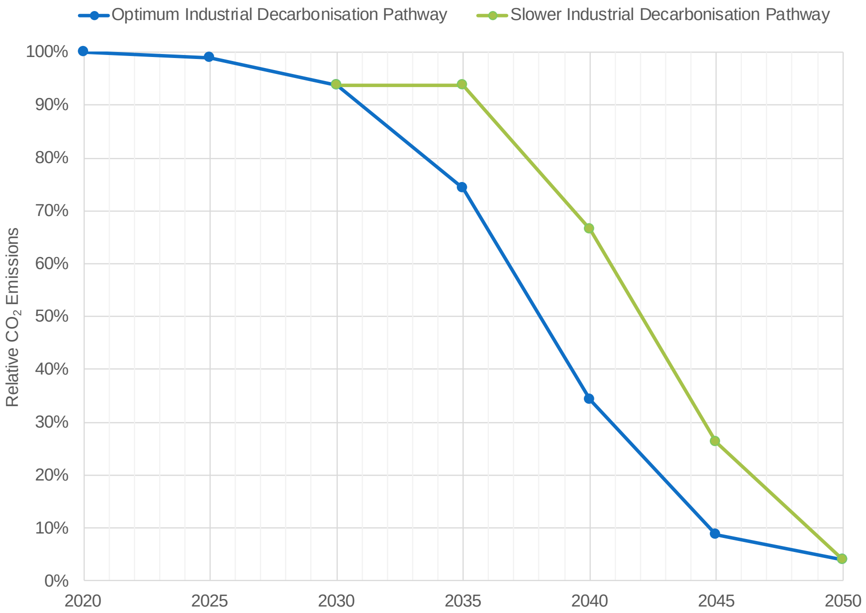
Key considerations and assumptions used in the development of the WWU network decarbonisation pathway are as follows:

Hydrogen Demand and Supply Development

- Major emission reduction gains at scale to be achieved by targeting large scale industrial emitters, particularly from the six main industrial clusters which contribute to almost half of the industrial emissions in the UK.
- Industrial clusters will drive the development of decarbonisation roadmaps, with initial hydrogen generation anchor projects set to supply baseload energy demand from industry, upon which regional demand for hydrogen will be met with increasing hydrogen generation, transport and distribution infrastructure capacity.
- Unlike North Wales and the South-West, as a result of the LNG terminals located in Pembrokeshire in South Wales, the region is presently a gas producer as well as consumer. It is anticipated that such operations will continue in future – with Pembrokeshire and western South Wales likely to replicate existing gas operations with low carbon alternatives.
- A small number of larger emitters dominate present industrial emissions in North and South Wales and also the South West. The decarbonisation decisions taken these key stakeholders are likely to have an extremely significant impact upon the decarbonisation solutions and infrastructure which is implemented within WWU's region in future (as well as when it is implemented).
- The decarbonisation routes for industrial combustion processes (power and heat generation) are likely to be either fuel switching (hydrogen), electrification or CCUS. Steel industry could decarbonise by the use of Electric Arc Furnaces (EAF) or via the use of hydrogen if steelmaking processes are converted to direct-reduced iron (DRI).
- Power Plants represent the largest industry emitter group in the WWU supply area, with RWE's Pembroke CCGT power plant representing the single largest generator and emitter. In a scenario where dispatchable power generation continues to play a key role in managing renewable power intermittency and the operability requirements of the UK's electricity system, conversion of these power plants to hydrogen combustion would have the largest impact upon hydrogen production in the region.
- To realise their net zero ambitions for decarbonising industry the UK Government's ambition (as detailed in the Industrial Decarbonisation Strategy) is that industrial emissions will reduce by at least two-thirds by 2035 and by at least 90% by 2050. A potential industrial decarbonisation pathway in the region has been developed based on published and notional plans for the top-10 emitters, see Figure 24. The likely timing and degree of decarbonisation is indicative, and although a degree of uncertainty exists, it represents a credible informed estimate based on actual industrial decarbonisation projects and ambitions at the time of this study. Indicating that while delivering industrial decarbonisation before 2050 is likely to be

feasible, it is likely that the timeline for undertaking such activities will need to be accelerated if the infrastructure introduced as a result of the decarbonisation projects implemented in the industrial clusters is a pre-requisite to the subsequent decarbonisation of both non-industrial emissions in South Wales and also regional emissions in North Wales and the South-West.

Figure 24 Wales and South-West Industrial Decarbonisation Pathways



Hydrogen Transmission and Distribution

- The GB gas system is made up of a diverse range of supply sources with sufficient capacity to meet the demands of users. Gas supply and demand needs to balance on a daily basis, requiring a flexible system that can respond to demand peaks. It is expected that future hydrogen networks will replicate the current configuration and operation of the gas network. It is anticipated that a hydrogen NTS (hydrogen backbone) will be required to provide the main transmission infrastructure to transport hydrogen at high pressure from multiple supplies to deliver hydrogen to large consumers and gas distribution networks via offtakes – as per present day operations with the natural gas NTS. Along with hydrogen storage facilities, such a hydrogen NTS would provide security of supply on a daily basis by becoming a resilient supply to meet 1-in-20 peak hydrogen flows.
- A suggested regional network decarbonisation roadmap is as follows, aligned to the ENA's national level Hydrogen Network Plan:
  1. In the period 2025-2030 hydrogen production capacity will should reach at least 10 GW to supply industrial clusters via dedicated 100% hydrogen pipelines. Blends with up to 20 vol% hydrogen to be transported in selected parts of the network and initial conversion of salt caverns for large scale hydrogen storage. Supply of 100% hydrogen to the gas distribution network to start from 2030 once sufficient hydrogen production (10 GW) and a degree of hydrogen network development has been reached. Approximately 25% of the current NTS infrastructure requires to be repurposed to transport hydrogen by 2030.
  2. In the period 2030-2040 there will be a rapid expansion of hydrogen production, transport and distribution capacity. A growing hydrogen network connecting hydrogen pipelines between industrial clusters, gas network and storage facilities will be developed to form a

hydrogen backbone (aligned with NGG's Project Union concept). The iron mains replacement programme will be completed, enabling the roll-out of 100% hydrogen network conversion for supply to domestic users, transport and reaching industry beyond industrial clusters.

3. In the period 2040-2050 full network transition will be complete across WWU's area of operations, with a national hydrogen network in place supplied from hydrogen production, predominantly located within the clusters and dedicated production for network supply.

Security of Supply

- It is assumed that security of supply with a future hydrogen based low carbon gas network would have to be provided in a similar manner as per the current network operating model to meet 1-in-20 peak flows with storage provided by line packing and a robust supply source with high availability. Additional storage to line packing would have to be provided by additional physical storage or in a similar way to current operation by flexible NTS capacity bookings, in this case from the hydrogen supply source (e.g. hydrogen NTS).
- Network resilience would be provided by system capacity expansion (particularly in regard to storage) in consideration of potentially larger volumes of hydrogen compared to current volumetric flows of natural gas. The required additional network infrastructure (entry points, pipelines, offtakes, pressure reduction installations, buffer storage and equipment such as compressors) would have to be installed with an appropriate capacity to ensure the 1-in-20 peak hydrogen demands can be met. To manage WWU's current natural gas supply activities, seasonal demand variations in the region rely on NTS supplies, which are provided by LNG supplies in the South Wales region and access to underground gas storage for the North Wales and South-West of England regions. It is expected that this configuration and operation will be replicated for hydrogen, with the existing LNG importation facilities in the region able to provide both a feedstock for blue hydrogen production and also a means of offering long term energy storage in South Wales. As well as the introduction of other new hydrogen importation and production facilities which will provide further diversity.

Hydrogen Production

- The major challenge associated with co-locating hydrogen production with demand relates to the need to address security of supply requirements: a local plant supplying hydrogen to a region will not provide a highly resilient system and the ability to flexibly operate over the range of daily demand flows. Local hydrogen generation could be deemed acceptable to supply a single industrial user that could accommodate unavailability of hydrogen within the site operational philosophy. There will be local hydrogen generation, likely from electrolysis or from small scale SMR from biogas which could feed into the LTS. Hydrogen from these local sources would be supplementary to the main hydrogen supply like the current case of biomethane. Prior to creation of a nationwide hydrogen NTS, green hydrogen production projects would need to combine their operations with production of hydrogen from electricity imported from the grid to provide a secure supply of hydrogen to local consumers. Such a solution would require sufficient capacity and availability of electricity supply.
- The expectation for the transition to a low carbon gas network using hydrogen would be to establish locations where hydrogen would be produced at scale, via expansion of hydrogen production capacity in industrial clusters, accompanied by the development of a hydrogen NTS which would facilitate supply to consumers.
- Hydrogen production must be expanded beyond the level that is needed for use within industrial clusters to allow a widespread gas network conversion to take place from 2030.

Whilst the current NTS is used to carry gas from various entry points, it is anticipated that hydrogen supply will be sourced from the hydrogen produced at the industrial clusters, including supply from the interconnectors with the European hydrogen backbone.

- Historically, the LNG terminals at Milford Haven have contributed to up to about 20% of the UK's gas demand and have potential to supply up to 40% of the total gas demand at maximum send-out capacity. Therefore, substantial blue hydrogen could be produced such that the region becomes a net exporter of hydrogen. Blue hydrogen production at Milford Haven could then support a similar UK security of supply strategy to present day supply of gas from LNG. Blue hydrogen production in South Wales could also develop at Port Talbot depending on the chosen decarbonisation route for Steel industry.
- Blue hydrogen production capacity from the HyNet project is expected to supply industry and at least one major power station, with phased capacity expansion supporting decarbonisation of heavy transport and the gas network in the North West. It is assumed that capacity will be sufficient to supply North Wales, with adequate network resilience to ensure security of supply.
- There is also potential for the installation of alternative (or additional) green hydrogen generation capacity from electrolysis in the South West, North Wales and South Wales, particularly using power produced from floating offshore wind projects in the Celtic Sea.
- Importation of green hydrogen to South Wales in the form of ammonia may be possible in the long term, assuming global markets similar to current LNG trade are established by 2050.

Network Capacity

- Potential hydrogen flows that could be transported to meet pressure loss conditions are expected to result in energy flows that are not too dissimilar to those transported by natural gas, particularly in consideration of any existing margins between pipeline capacity and peak flows.
- Gas velocities for the case of hydrogen are likely to exceed the current design constraint 20 m/s set to mitigate the risk of erosion. An increase in maximum operating velocity allowance would allow increased volumes of hydrogen to be transported before investment in network reinforcement is required. This could be supported by erosion risk mitigation such as the injection of filtered gas, use of polyethylene piping and risk-based pipeline integrity management.

Storage Capacity

- Energy storage is required to maintain network resilience and meet security of supply obligations and ensure sufficient supply during periods of peak demand. Hydrogen supply is expected to follow a similar philosophy, with diurnal variability in demand managed by firm and flexible offtake capacity bookings and line pack storage. Seasonal demand variations are expected to be managed by underground gas storage, LNG and gas supplies via the interconnectors with European gas infrastructure as per current practice.
- The hydrogen volume required to store the same amount of energy as natural gas is about 3 times the volume of natural gas. Following network conversion to hydrogen, volumetric line packing storage capacity will remain similar to current capacity based on operation at similar pressures and excluding any volume additions by network reinforcement. Therefore, energy storage provided by hydrogen line packing will be about a third of current gas line packing. To meet hourly peak demand, the gas network will either have an increased reliance on

flexible hydrogen NTS capacity bookings or will require external storage. Hydrogen storage in the form of compressed hydrogen or other forms could be provided, with the condition that hydrogen is made available to meet instantaneous (hourly) demand.

- Given the limited scope to provide hydrogen storage, particularly to support security of supply against diurnal demand variations, the potential for gas supply capacity set at the peak rate appears to provide a feasible way to approach security of supply. This essentially means a reliance on supply from a hydrogen transmission pipeline. The ability to replenish the network during periods of demand near peak flows through the hydrogen NTS offtakes would need to be evaluated by means of hydraulic modelling, which would identify potential bottlenecks in the system to ensure network extremities do not reach a critical low pressure during this scenario.

8.3. CONCEPTUAL PLAN INSIGHTS

The following summary on gas network conversion collates the insights drawn from the Regional and Sub-regional Conceptual Plans which have been developed for the Regional Decarbonisation Pathways project.

8.3.1. REGIONAL CONCEPTUAL PLAN

The following insights have been drawn from the Regional Conceptual Plan work:

Global Insights with UK-Wide Relevance

1. To deliver net zero, we need to fully decarbonise the UK's energy systems – addressing present day petroleum (40%) as well as electricity (18%) and gas (34%) demand (BEIS Figures for 2019). Even with the potential for demand reduction due to energy efficiency, demand side management and transition to alternative supply arrangements (e.g. heat pumps with reduced heat demand compared with gas boiler due to their CoP characteristic), it is therefore difficult to envisage how a future UK net zero energy system could be achieved in practice without developing low both carbon electricity and gas networks. Especially given the low energy transfer rates, higher visual impact and increased requirement for redundant circuits associated with electricity transmission and distribution networks compared with gas.
2. When engineering net zero, it is important that anticipated daily and annual energy demand and production profiles are taken into account as well as considering annualise energy values: There is a large variation between winter peak and summer minimum demand for heat (potentially 5:1) whereas transport demand remains more constant through the year.
3. Even when considering a high electrification scenario for WWU's area, it is anticipated that the existing gas system footprint will largely require to be retained (although potentially with a lower utilisation factor) to help supply the UK's winter peak energy demand. The study therefore has not identified a potential decarbonisation pathway which would allow decommissioning of the present gas network to be considered.
4. To roll out hydrogen at scale across WWU's area and achieve this by 2050, it is anticipated that replication of the existing NTS functionality for natural gas – probably in the form of a hydrogen NTS will be required by the mid-2030s at the latest.
5. Technical solutions to facilitate the transition from natural gas to hydrogen-based gas transmission system involve either the use of separate NTS pipeline systems, or the application of hydrogen blending (above 20%) and de-blending at scale. Initial indication obtained from National Grid Gas during delivery of the study is that parallel transportation of hydrogen and natural gas is assumed to generally be the preferred transition method across the UK since it is not anticipated to be economically viable to install the necessary gas meters for an operational period which may only last about 10 to 15 years until 100% hydrogen operation is achieved. Further evidence needs to be produced to confirm whether this perspective is correct – both nationally and also regionally.
6. Radially supplied parts of WWU's LTS network (e.g. North Wales and the SouthWest) can potentially be sequentially transitioned to hydrogen.
7. The situation in South Wales is potentially more complex – since in this region there is also the capability for importation of natural gas (in the form of LNG) which is exported into England the rest of the UK and also the potential for future import of H2 at scale going forwards – whether produced from LNG or floating offshore wind farms.

8. If blending / deblending is not considered a feasible energy transition solution, then installation of a new parallel H2 capable pipeline system would be required to facilitate the transition to net zero – potentially requiring initial strategically located pipelines to be ready for operation as early as the late 2020s to help facilitate development of low carbon production projects in the western part of South Wales. And by the mid-2030s at the latest if wider decarbonisation of energy demand in South Wales and also the South-West is to be achieved by 2050. Timescales for delivering the energy transition in North Wales are likely in practice to be somewhat dependent upon the project and infrastructure implementation schedule being developed by the HyNet programme.
9. No energy transition sequencing philosophy present exists for the UK, with each region presenting somewhat parallel progression to deliver net zero by 2050. However, given that South Wales exports energy (both gas and electricity) to the rest of the UK, a regionally based programme which delivers installation of H2 NTS infrastructure followed by H2 LTS infrastructure in time to achieve net zero energy system operations by 2050 will potentially fail to also support wider UK energy system decarbonisation by 2050 – i.e. if we need to achieve net zero in South Wales earlier so as to then facilitate the decarbonisation other, harder to reach, parts of the UK (such as the Midlands). An energy transition sequencing philosophy for the UK is urgently required to determine whether decarbonisation of strategic regions, such as South Wales, should be prioritised with significantly earlier investment and infrastructure in order to achieve UK energy system decarbonisation by 2050.

Regionally Focused Insights

1. Based upon present UK Government policy, which is prioritising decarbonisation in identified Industrial Clusters, it is anticipated that initial decarbonisation deployment projects will be industrially focused – likely involving the largest sites and/or emitters.
2. Engineering and technical review of the modelling outcomes produced in the three – High Electrification (ELE), Balanced (BAL) and High Hydrogen (HYD) – scenarios modelled by ESC has concluded that they represent credible future outcomes for delivering a net zero energy system within WWU's area of operations by 2050.
3. However, this analysis has also identified that the strategic decarbonisation decisions made by a small number of industrial based stakeholders across WWU's operating region is likely to have significant influence on the energy transition and decarbonisation solutions which are deployed, and also the timing of their deployment: I.e. In terms of which of the modelled scenarios is likely to be closest to what the actual future energy transition deployment will look like.
4. The regional utilities such as WWU, SP Manweb and WPD, plus the larger number of smaller emitters will focus on developing solutions which build on the initially deployed infrastructure – whether in the form of low carbon gas (e.g. hydrogen) networks, CO2 export systems and/or increased electricity system capacity.
5. Developers including existing site operators require a 'route to market' for their energy transition and decarbonisation projects which establishment of the presently in-progress hydrogen and CCS based business models will help resolve. The HyNet (NorthWest) and East Coast Clusters have been selected for Track-1 in the UK Government's cluster sequencing initiative – which is presently also supporting project development activities in North Wales. However, with ability to access a pipeline-based CO2 T&S system a pre-requisite to access Track-1 funding, the present cluster sequencing arrangements excludes project developers in South Wales from engaging with the initiative. Complimentary policy

support for non-pipeline CO_2 transport solutions is required to similarly facilitate projects in South Wales and the South-West and enable foundational blue hydrogen production infrastructure to be established in the region.

South Wales Specific Insights:

With its relatively unique characteristics, South Wales provides an almost unique opportunity to use the region to pioneer development and delivery of net zero energy system operations across an entire region within the UK due to the following aspects:

1. South Wales one of the regions assigned by UK Government as an industrial cluster – with the presence of a relatively high-volume industrial demand (and emissions) in the region. As a result, decarbonisation in South Wales is expected to be led by industry – reflecting UK & Welsh Government policy focus and funding;
2. South Wales has radial energy system connections from South Wales to England and the Rest of the UK (for both gas and electricity networks) – offering a relatively bounded area for conversion:
    - With energy production and demand concentrated in the relatively narrow strip of land between the Bristol Channel and the national parks in Mid Wales.
    - Within the region, present surplus energy production (gas and electricity) offers energy supply and security of supply to the UK as a whole.

The potential to continue such energy production operations in a future low carbon UK energy system infers that such operations are likely to be required ahead of the timeline necessary to deliver net zero in South Wales by 2050, if these operations would also be essential to facilitating delivery of a wider UK net zero energy system as well.

8.3.2. SUB-REGIONAL CONCEPTUAL PLAN

- Wales is likely to be a net exporter of hydrogen. South Wales in particular given the proximity of LNG importation terminals into Milford Haven and the location of major industries is likely to be an exporter of hydrogen to England both within the WWU supply area to the South West and to the Midlands. North Wales and the WECA, Gloucester, Wiltshire & Somerset Regions may also become net exporters of green hydrogen from 2040 onwards.
- There is major potential to repurpose existing infrastructure in all areas. The majority of the LTS system in South Wales and the South West was constructed from pipe material strength grade of X52 and below. These pipe materials are suited to the transportation of hydrogen however, where pipelines have been constructed of higher strength grade then further work may be required to be undertaken prior to conversion to confirm their suitability.
- There are also a number of sections of the LTS network in South Wales which are over fifty years old and may potentially reach the end of the useable life shortly. Where these pipelines are to be replaced as part of a planned programme then it is recommended that they are replaced with pipelines suitably oversized to help provide some storage capability via linepack and with a pipe material grade which suitable for hydrogen service.
- All three scenarios will require similar levels of new pipeline infrastructure investment to enable conversion to hydrogen.

- Under some scenarios certain areas (North Wales) start the conversion process as early as 2030. Given it can take circa 5+ years between starting the planning process and commissioning a new pipeline. It would be prudent to start conceptual planning and pipeline routing studies shortly, in areas where early conversion may be required.
- Across most areas there is generally a high retention of the domestic and commercial (non-industrial) customer base.

8.4. FUTURE WORK AND ACTIVITIES

Delivery of the present Conceptual Plan study scope has identified the following areas and aspects which could beneficially be the focus of future activity and work:

Stakeholder Engagement

Based on the work performed in delivery of the regional decarbonisation pathway work, it is recommended that the following follow-on key stakeholder engagement activities be undertaken on an ongoing basis going forwards:

- Engage with key industrial stakeholders across WWU's area of operations to generate and then track and update proposed decarbonisation plans – as a key input to WWU's own energy transition programme. This activity can be facilitated through engagement with both established (SWIC Deployment and HyNet) and also emerging (Western Gateway and Hydrogen South West) cluster groups;
- Continue to engage with the other gas and electricity utilities (both regionally and nationally) to collectively develop more detailed and granular proposals to decarbonise existing GB energy networks; and
- Engage with regulatory bodies and other key stakeholders such as the Welsh and UK Governments to advocate for the need to lead on the implementation of decarbonisation infrastructure projects rather than reacting to market based proposals (as per present practice) – since there is a 'chicken and egg' threat that lack of certainty on new decarbonisation infrastructure could delay or in a worst case prevent the ability to obtain sanction and achieve FID for discrete energy transition and decarbonisation projects.

Net Zero Masterplan

Although ENA has produced a national level Hydrogen Network Plan working in conjunction with Britain's five gas network companies, this plan is preliminary in nature, and does not comprehensively take account of future end-use vector energy transition requirements or describe the detailed sequence of activities which will be needed to realise an integrated UK low carbon energy system by 2050. There is a need to develop the required energy networks transition activities as a more detailed engineering programme which will then need to evolve and be further developed on an ongoing basis. Managing such a programme is potentially a gargantuan task requiring that a large number of projects be progressed through their implementation lifecycle over a wide range of timescales, while also ensuring at the same time that the end goal of delivering a net zero UK energy system by 2050 is realised while ensuring system operability and security of supply requirements are maintained throughout the transition period.

Net zero energy networks masterplans need to be developed to help inform and generate a more detailed engineering delivery programme. To ensure that comprehensive inputs are generated, it is recommended that this should be reviewed from both a top down, and a bottom up perspective:

- WWU working with the other gas and electricity utility companies contributing to the generation of a national Net Zero Masterplan for Great Britain as a whole;
- Production of a Regional Plan Net Zero Masterplan, which may optimally consider North Wales, South Wales and the South West separately due to the radial and somewhat separate nature of their gas network interconnections with the rest of the UK;
- And also potentially a more granular sub-regional plan, e.g. considering discrete areas within South Wales individually – such as Pembrokeshire, Neath Port Talbot and Cardiff / Newport – as well as the Bristol and Gloucestershire within the South West and the potential for that area to align with South Wales.

It is important that the sequency of steps necessary to optimally deliver net zero by 2050 are identified and that this knowledge is used to inform the development of regional plans for all of the UK. As noted elsewhere in this report, the LNG import terminals in South Wales not only supply around 20% of the UK's gas demand, but unlike the hydrocarbon production activity in the North Sea, are more likely to remain operational beyond 2030 as they also provide the basis for future importation of low carbon gas whether in the form of hydrogen or ammonia.

A Net Zero Masterplan for the UK needs to consider the sequencing of hydrogen production and demand as well as the associated network infrastructure. Development of such a masterplan would confirm the expectation articulated in this report that early development of blue and green hydrogen production in South Wales along with the necessary associated hydrogen transportation infrastructure is potentially on the critical path for net zero delivery.

Hydrogen Pipeline Engineering Activities

- Feasibility studies for hydrogen transmission pipeline(s) including:
    - In South Wales, from Milford Haven through to Dyffryn (Phase 1), Port Talbot (Phase 2), Newport (Phase 3) and eventually linking to hydrogen NTS backbone (East Cost Hydrogen).
    - In North Wales, from Maelor through to HyNet at Stanlow. (Phase 1).
    - In the South West, from a potential hydrogen production facility in Avonmouth to local major emitters and NTS offtakes in the Greater Bristol area (Phase 2).
- Undertake Level1 (IGEM/TD/1 Ed 6) Route Corridor Selection studies for the Phase 1 hydrogen pipelines.
- Hydraulic modelling of the network to assess detailed network conversion plans including pipeline reinforcement.
- Undertake an assessment of the existing WWU design and operability data set for the LTS system, to ensure its readiness and suitability for use in the repurposing assessment.
- Undertake a detailed repurposing assessment of the existing LTS network in accordance with IGEM/TD/1 Ed 6 supplement 2.

Hydrogen Distribution and Storage

- Undertake hydraulic modelling to quantify network storage requirements (line pack and off-grid distributed above ground storage).
- Quantify requirements for initial industrial users for their potential storage requirements e.g. via tube trailers etc.

- Undertake a detailed assessment of the of the potential to use salt formations in or near the southern part of the WWU supply area (Portland / Somerset) as potential future hydrogen storage locations.
- Form a joint industry R&D study project into the potential use of sandstone formations for hydrogen storage.

9. CONCEPTUAL PLAN METHODOLOGY

9.1. OVERALL METHODOLOGY

The **Strategic Plan** has been developed using two of ESC's national whole energy system models. The modelling outputs have been used to provide insights about how the wider energy system and networks within it may look in 2050 under the agreed scenarios.

These outputs have then become the inputs for the **Conceptual Plan**, ensuring that the technical and engineering work starts from a position, consistent with the least-cost pathway to Net Zero for the WWU regions and UK. See below for further detail on each of the two main deliverables.

9.2. CONCEPTUAL PLAN

The outputs from the Strategic Plan have been analysed to assess the infrastructure requirements against the existing and evolving gas network configuration, sources of decarbonised gas and storage to develop concept designs for each scenario. Different analyses have been produced at two geographical levels, the **regional** level and the **sub-regional** level.

9.2.1. OVERARCHING GAS NETWORK DECARBONISATION PHILOSOPHY

The engineering analysis undertaken in delivering the conceptual plan scope takes account of various practical considerations for decarbonisation of the gas network around distribution of increasing volumes of hydrogen and reducing volumes of natural gas through to 2050. With the intention of providing a practical context to support further consideration of the outputs of the energy systems modelling work.

Practical considerations include:

- Alignment with gas network decarbonisation pathways, as defined by UK policy including the Government's Ten Point Plan for a Green Industrial Revolution and Net-Zero Strategy, BEIS Industrial Decarbonisation Strategy and more specifically the ENA's Britain's Hydrogen Network Plan and the UK Government's Industrial Clusters Mission.
- Gas network configuration and operation in regard to security of supply, including considerations such as network resilience, the need for multiple gas supplies, the role of the gas transmission system, gas demand variation including 1-in-20 peak demand, demand forecast, in-day storage, National Transmission System (NTS) capacity bookings, and seasonal large scale gas storage.
- Existing gas and electricity system regional architecture and capacity.
- Present-day energy system demand levels and the breakdown of types of energy consumption across WWU's supply area.
- Decarbonisation options for large, concentrated greenhouse gas emitters, particularly the largest industrial sites where the decarbonisation decisions take will potentially have the most significant impact on the energy systems infrastructure which will facilitate decarbonisation in their local area.
- Decarbonisation options known to be being considered by the SWIC Deployment partners within this IDC2 funded programme.

An overarching gas network conversion philosophy has been defined to include relevant aspects from the considerations above, with gas network configuration and operation developed in a way and timeline integrally aligned with overall gas network plans to reach a net-zero end state by 2050 as defined by energy systems modelling. This philosophy has been used to drive the development of the Conceptual Plan.

9.2.2. REGIONAL CONCEPTUAL PLAN

The Strategic Plan has produced whole energy system analysis for the agreed scenarios for the two major WWU regions, i.e. Wales and the South West of England. The outputs based on the WWU scenarios have been assessed by Costain to establish high-level concept designs for these regions.

Costain have applied engineering processes, knowledge and principles to interpret the Strategic Plan scenario regional outputs and determine what they mean at a regional level, from a technical gas network perspective. The Strategic Plan scenario outputs have been compared with other leading industry commentary (e.g. ENA scenarios) plus actual / present day BEIS energy consumption / production figures and emissions data to augment them with an engineering and technical perspective to enable development of a gas network plan for North Wales, South Wales and the South West. This regional division has been applied in consideration of gas network configuration and geographical distribution of demand. This analysis provides a complimentary and contextualised view of the Strategic Plan scenarios which confirms that the outputs produced in the ESME scenarios are credible. However, it also indicates that actual future outcomes (in terms of the balance of energy consumption across the potential energy vectors in WWU's area of operations) could be significantly influenced by strategic decisions made by a relatively small number of large industrial emitters who are presently located in the region and / or potential future additions – e.g. most specifically floating offshore wind. The Strategic Plan scenario outputs and consideration of practical considerations as defined in the overarching regional pathway have been used to identify the likely locations within the regions for hydrogen production and demand. LTS network designs (GIS Maps) have been developed to represent the network conversion plans through to 2050.

The scope is delivered from the assessment of the existing regional aspects to develop an engineering and technical perspective on what 'might be possible' in terms of future hydrogen production, storage and demand in North Wales, South Wales and the South West.

9.2.3. SUB-REGIONAL CONCEPTUAL PLAN

The Strategic Plan scenario outputs include network conversion dependency maps for 2050. Costain have used this information as the inputs into the sub-regional Concept designs and have applied an engineering / technical perspective to analysing how the 2050 outputs might be realised in practice across WWU's network. These have been developed at five-year time periods to detail the conversion pathways and develop high-level regional conversion strategies.

The Strategic Plan scenarios provide a high-level assessment of the network requirements in 2050. Costain have used these outputs as the starting point for developing Conceptual plans for the 6 sub-regions. Network maps have been produced for those 6 sub-regions and these are shown in Section D.

LTS network design outputs are delivered under the Sub-Regional Concept Plan.

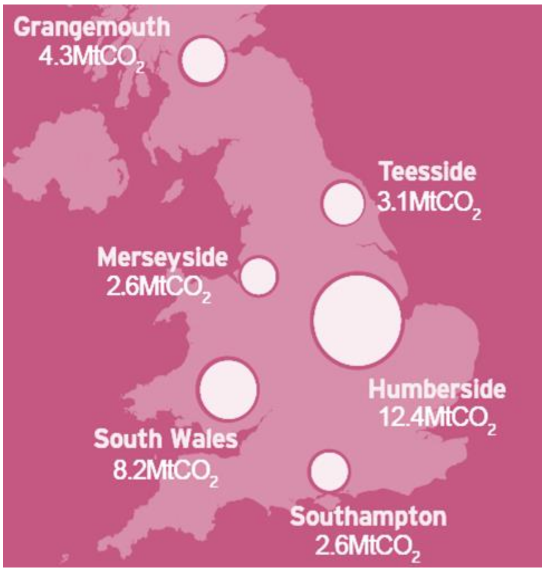
10. ANALYSIS OF MAJOR EMITTERS AND ENERGY DEMAND

10.1. INDUSTRIAL CLUSTERS DRIVING DECARBONISATION

As a result of present government focus and funding, initial decarbonisation solutions are anticipated to be implemented as a result of funding provided to support industrial cluster deployment projects, where reducing the emissions of a small number of key stakeholders at strategic sites could make the most significant impact.

The UK's six main industrial clusters contribute to almost half of the industrial emissions, with combined annual emissions of around 33 million tonnes of CO_2 as shown in Figure 25.

Figure 25 Industrial Cluster's Estimated CO_2 Emissions



Source: BEIS

The Industrial Strategy Challenge Fund (ISCF) is constituted by 23 challenges developed around 4 themes. The Industrial Decarbonisation Challenge (IDC), part of the ISCF Clean Growth theme, aims to accelerate the cost-effective decarbonisation of industry enabling the deployment of low-carbon infrastructure at scale by the mid-2020s. IDC aims to develop at least one low-carbon industrial cluster by 2030, and the world's first net-zero carbon industrial cluster by 2040.

Through the UK Government's Industrial Clusters missions and funding mechanisms such as ISCF and IDC, it is anticipated that development of initial decarbonisation solutions in the UK will be led out of the industrial clusters and driven by a small number of large emitters who will make the largest initial impact on decarbonising their operations.

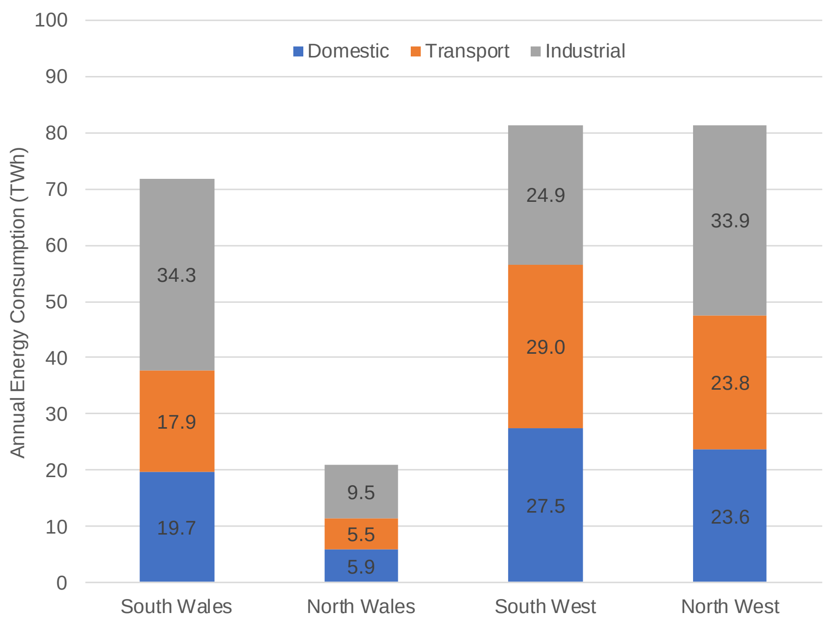
Emissions reduction at scale is therefore likely to first occur in industry, and this will drive the development of decarbonisation roadmaps, with initial hydrogen generation anchor projects set to supply baseload energy demand from industry, upon which regional demand for hydrogen will be met with increasing hydrogen generation, transport and distribution infrastructure capacity.

Developed decarbonisation solution programmes will not necessarily be delineated along regional or Local Authority area boundaries. The evolution of hub-based solutions in the Industrial Clusters is likely to cause others to gravitate towards their orbit, with North Wales becoming a satellite of the Merseyside Industrial Cluster in the North West (HyNet), and the Gloucester and Bristol areas potentially aligning with the South Wales Industrial Cluster.

10.2. REGIONAL ENERGY CONSUMPTION ANALYSIS

Energy consumption data for Domestic, Transport, Industrial, Commercial and Other users for the for Wales and the South West has been plotted in Figure 26. This analysis is based on BEIS energy consumption data based on year 2019 as representative of present-day energy demand. Although not part of the WWU supply area, or in scope, the North West region has been also included to provide additional context, since its emissions will be addressed by the Merseyside Industrial Cluster and the HyNet programme. The lead provided by HyNet in the deployment of initial decarbonisation solutions is anticipated to influence the solutions which will subsequently be applied within the North Wales region.

Figure 26 Sub-National Total Final Energy Consumption



Source: BEIS Subnational Total Final Energy Consumption, United Kingdom, 2019

For Wales (North and South), the proportion of energy demand from industry is near 50% of the total, whilst energy used for transport and domestic use is about a quarter each. For the South West, the proportion is about a third for each type of final user due to a lower presence of industry. This proportion shows that targeting industrial emissions reduction in North and South Wales will result in larger percentage regional decarbonisation gains than in the South West.

Although some industry is dispersed, industrial sites tend to cluster around industrial areas and business parks. This allows industry within clusters to follow similar decarbonisation routes supported by common energy supply infrastructure to achieve somewhat optimised technical and financial solutions. With both the larger absolute industrial demand in South Wales and the North West, combined with the concentration of that demand within a relatively small geographical area demonstrating the rationale behind the UK Government's Industrial Clusters Mission initiative.

Domestic demand is highly distributed over a large living area and decarbonisation highly depends on decarbonisation of electricity and gas networks. With future low-carbon domestic demand potentially including an element of transport demand as well as heat and electricity demand. It is initially easier to reduce GHG emissions from domestic energy demand by electrifying end-use, unlike the transition to a low carbon gas network, electricity supply (inf the form of electrons) will remain unchanged. However, with the gas network's ability to supply greater energy demand, and greater demand ramp rates using less (and also less visually intrusive) transmission system infrastructure, the ability to initially realise electrification-based solutions does not necessarily also mean that electrification will offer a technically or financially optimal solution. This is especially relevant to an island nation such as the United Kingdom which is relatively densely populated and where the opportunity to introduce a significant volume of new energy transmission system corridors is potentially limited.

Energy used for transport is also distributed, currently supplied in the form of petroleum fuels. Decarbonisation of transport will also rely on the supply of decarbonised energy through the future regional electricity and gas networks and be dependent upon the future designed energy transfer capacity in those networks.

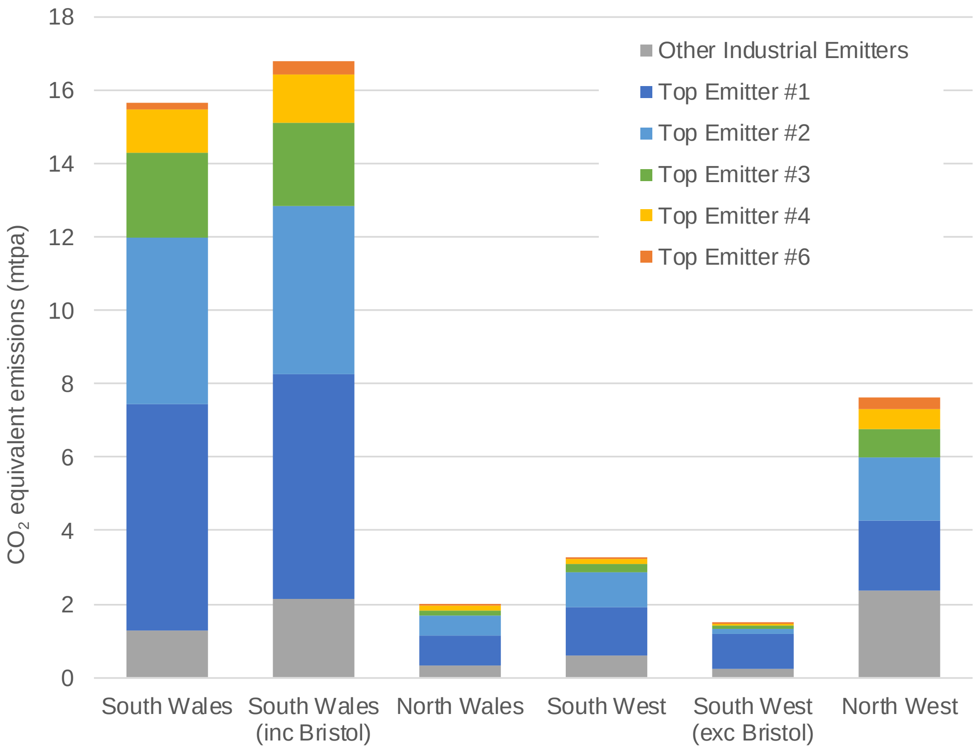
Significant uncertainty exists at present in terms of what a balanced future net zero energy system architecture might look like in terms of distributed demand for domestic use (for space heating mainly, plus hot water and food cooking) and for transport fuel. Initial transition to decarbonisation is perceived to be initially facilitated (but not necessarily low cost) with electricity-based solutions. However, significant challenges are expected in terms of the electrical infrastructure required due to the magnitude and large variability of the energy demand associated to space heating (currently supplied by gas).

10.3. INDUSTRIAL EMISSIONS BENCHMARK

A breakdown analysis of industrial emissions is shown in Figure 27 for the Wales and South West regions (including North West of England due to its anticipated influence on North Wales). The presented analysis is based upon the National Atmospheric Emissions Inventory (NAEI) database published by BEIS for the year 2018.

Total energy demand levels are similar in South Wales, North West and South West of England (see Figure 26). However, industrial demand (and emissions) are markedly higher in South Wales than in the other regions. Figure 27 also provides indication of the impact on South West industrial emissions if emitters in the Bristol area were to align with the South Wales region (and the South Wales Industrial Cluster deployment programme) due to their geographical proximity.

Figure 27 Wales and South West Industrial Emissions Breakdown by Top Emitters



Source: NAEI Database 2018. Sites no longer operating excluded.

A small number of larger emitters (and site locations) dominate present industrial emissions in North and South Wales and also the South West – although the total tonnes of CO_2e emitted are very different, mainly due to fuel type used. The top three industrial emitters in each region contribute by about 70% to 80% of the total industrial emissions in Wales and the South West. These major emitters also represent a small number of industrial sectors as shown in Table 8, with major emitter sectors being power generation, iron and steel, refineries, cement and chemicals. These industrial sectors are likely to select from a similar range of decarbonisation solutions e.g. fuel switching or CCUS for power generation. With the largest emissions occurring in South Wales, the presented emissions are arranged in order of the largest sectoral emitters in that region.

Table 8. Wales and South West Industrial Emissions Breakdown by Sector

Sector	CO_2 Emissions (ktpa)			
	South Wales	North Wales	South West	North West
Major power producers	6,628	952	2,290	2,153
Iron and steel industries	6,434	55		
Processing and dist. of petroleum products	2,287		0.1	1,898
Cement	338	555		
Chemical industry	249	31	14	1,412
Processing and distribution of natural gas	237			1
Waste collection, treatment & disposal	190	3	492	487
Other mineral industries	121	39	225	497
Minor power producers	80	11	39	1,771
Food, drink and tobacco industry	70	33	97	289
Paper, printing and publishing industries	60	53	43	274
Public administration	31		104	143
Electrical engineering	16	0.005	0.01	19
Non-ferrous metal industries	10	13		46
Mechanical engineering	8	0.03		10
Vehicles	7.6	77	11	77
Commercial	0.6	0.16	2	23
Other fuel production	0.41			
Water & sewerage	0.15	0.04	7	2
Miscellaneous	0.02	0.007	0.04	0.03
Textiles, clothing, leather and footwear	0.003		0.02	0.05
Agriculture, forestry and fishing			0.001	0.001
Construction			0.001	
Oil and gas exploration and production		54		
Other industries	0.15	136	10	

Source: NAEI Database 2018.

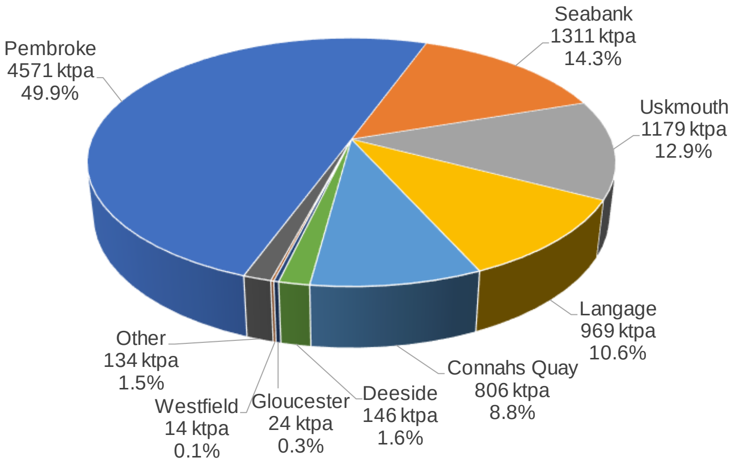
The decisions taken by the major emitters to decarbonise their emissions will have a significant impact on the energy transition solutions deployed in the Wales and the South West. Projects driven by major emitters are expected to result in the development of infrastructure which the much larger number of smaller industrial emitters can potentially also utilise to decarbonise their operations – potentially without also necessarily requiring the deployment of significant further energy system decarbonisation infrastructure.

10.3.1. POWER GENERATION EMISSIONS AND ENERGY DEMAND

Greenhouse gas (GHG) emissions, reported as CO2 equivalent emissions associated with power generation operations are about 10 Mtpa for the WWU area and correspond to nearly half of the total industrial emissions of 22 Mtpa.

Combined Cycle Gas Turbine (CCGT) Power Plants presently provide the primary means of managing renewable intermittency and the operability requirements of the UK's electricity system. CCGT Power Plants represent the largest industry emitter group in the WWU supply area, predominantly in the South Wales and South West. Of the 44 major and minor power producers listed in the National Atmospheric Emissions Inventory (NAEI) database, the top five account for around 97% of present-day GHG emissions from this sector, see Figure 28.

Figure 28 Emissions for Power Generation in WWU Area (ktpa CO_{2e})



Source: NAEI Database 2018. Sites no longer operating excluded.

There is significant present uncertainty in terms of the likely future electricity generation mix in the UK and the future requirements for electricity system requirements such as flexibility of electricity production, system operability and long duration (including inter-seasonal) storage capacity. While it could be possible to largely realise low carbon operations replicating present day CCGT operations with the application of CCUS, fuel switching with hydrogen will potentially allow greater flexibility of power plant operations as well as increased economies of scale if future hydrogen production plants are sized to serve multiple end-use vectors – including heat, transport and industrial use as well as electricity generation.

Table 9 shows the top ten emitter power plants in the WWU supply area, including an estimated hydrogen demand for a possible fuel switching decarbonisation route in function of current energy consumption.

Table 9. Power Plants in Wales and South West

Power Station Site	Region	CO_2 Emissions (ktpa)	Potential Hydrogen Consumption	
			Annual (TWh)	Daily Average (tpd)
Pembroke	South Wales	4,571	21.1	1,750
Seabank	South West	1,311	6.0	500
Uskmouth	South Wales	1,179	5.4	450
Langage Energy Centre	South West	969	4.5	370
Connahs Quay	North Wales	806	3.7	310
Aberthaw B	South Wales	497	0	0
Baglan Bay	South Wales	350	0	0
Deeside	North Wales	146	0.7	60
Gloucester	South West	24	0.12	10
Westfield Industrial Park	South Wales	14	0.06	5
Other	Wales / South West	134	0.6	50

Source: NAEI 2018 emissions database

Decarbonisation plans on a few specific sites, specially the top five emitters, will dominate future scenarios and drive decarbonisation in the region. Therefore, having the major power plant operators decide to convert some (or potentially all) of these power plants to hydrogen combustion would have the largest impact upon hydrogen production in the region. The hydrogen production infrastructure developed around power generation will prove a strong basis to then enable other hydrogen-based decarbonisation solutions in industry (in cluster or distributed) and later on users connected to the gas network i.e. domestic, commercial and transport users. Equally, if these power plant operators do not decide to decarbonise using hydrogen, then this would likely delay or even inhibit the development of other hydrogen-based decarbonisation projects within the region. Assuming that CCGT Power Plants continue to be the most effective means of balancing the intermittency of renewables and supporting electricity system operability and the electricity system demand increases, these could perform a similar role combusting low carbon fuel as hydrogen. Taking present-day installed capacity as a basis, the potential future demand for hydrogen in power plants within WWU supply region will be dependent upon both decisions to convert and also the future operating load factor of those power plants. However, if the full regional installed power plant capacity was converted to hydrogen and maintained a similar load factor to that achieved today, it is estimated that in excess of 40 TWh of hydrogen would be required per annum to supply these power plants alone. Furthermore, this could potentially be a conservative estimate: in consideration of high electrification scenarios where the future electricity demand is increased by a factor of two or three times the present-day demand.

The Pembroke Power Station operates flexibly in response to intermittency in renewable power generation, and therefore it does not serve a baseload demand. It is anticipated that the initial blue hydrogen production project would also ideally be able to inject hydrogen into the gas distribution network, at the times the power station is operating at part load or not operating. Hydrogen would be blended with natural gas potentially as early as 2025-2030 to maximise the utilisation of the hydrogen production plant. This would allow realising a commercially acceptable business case for such a blue hydrogen project whilst decarbonising users supplied from the gas distribution network (domestic, commercial, industrial). A hydrogen HP transmission pipeline would be key to connect hydrogen production at Milford Haven with the gas distribution network injection point, likely at the Dyffryn NTS offtake and gradually extending east to form part of a hydrogen transmission system.

The magnitude of hydrogen production required to realise 100% hydrogen combustion for the Pembroke Power Station could be from 7 TWh to about 28 TWh per annum depending on the number of units being converted. It is likely that such a project would need to be developed in conjunction with implementation of a UK hydrogen NTS network, such that this provides the required transmission infrastructure to export surplus hydrogen (in consideration of power plant load) to South Wales and England.

Based upon present UK Government timescales, an initial hydrogen production project at Milford Haven could be operational by the late 2020s. While full conversion of the Pembroke Power Station and installation of a UK hydrogen NTS could potentially be realised in the mid to late 2030s.

With a hydrogen NTS being available for export of hydrogen, the production of blue hydrogen in Milford Haven does not need to be limited to the production of hydrogen to be combusted in the local Pembroke Power Station (and potentially in the adjacent Pembroke Refinery). Given the LNG terminal import capacity, substantial hydrogen could be produced such that South Wales becomes a net exporter of hydrogen. Blue hydrogen production from LNG could then support a similar UK security of supply strategy to present day supply of gas from LNG. Potentially also supplemented by green hydrogen production (e.g. produced from floating offshore wind projects in the Celtic Sea) and/or the importation of green hydrogen (potentially in the form of ammonia) in a similar manner to the present importation of LNG.

10.3.2. INDUSTRIAL EMISSIONS AND ENERGY DEMAND

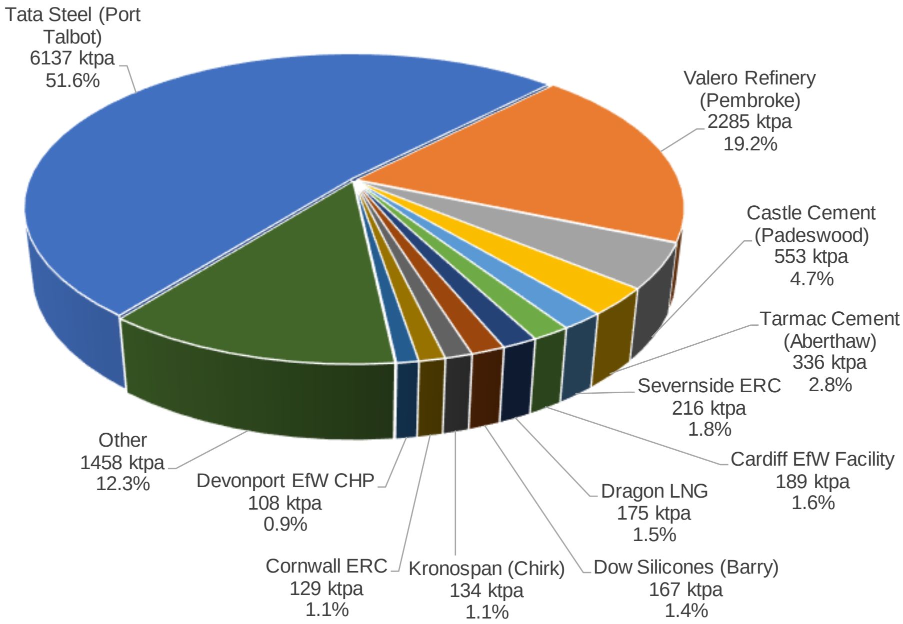
Major industrial decarbonisation projects likely to be located in the Industrial Clusters.

Similar to outcomes of the analysis for Power Plants in the region, a few major non-power producer industrial emitters in the WWU supply area comprise the majority of emissions. Almost 80% of the total CO2 emissions from industrial non-power generation emitters (12 Mtpa) in the WWU area are produced at just four site locations (see Figure 29):

- Tata Steel (Port Talbot)
- Valero Refinery (Pembroke)
- Castle Cement (Padeswood)
- Tarmac Cement (Aberthaw)

Tata Steel, Valero and Tarmac are involved in the SWIC Deployment project, while Castle Cement are progressing decarbonisation of their site operations in North Wales as part of the HyNet programme.

Figure 29 Emissions for Non-Power Industrial Energy Users in WWU Area



Source: NAEI 2018 emissions database

The potential decarbonisation options and implications are described below to put in context the potential for industrial fuel switching driving hydrogen demand. For the routes selected in the assumptions for energy systems modelling scenarios, refer to the Strategic Plan.

Power Generation Decarbonisation Pathway Options

The decarbonisation route for conventional power generation plant is likely to be binary, either hydrogen fuel switching or CCUS (if they remain operational). Forecasting likely decarbonisation solutions for non-power producer industrial emitter sites is more uncertain, both in terms of the selected site solutions and the potential phasing of those solutions. Some of the potential decarbonisation routes are described below. Site closure (or relocation) could be a potential regional emissions reduction option depending on particular business drivers.

Iron and Steel Industry Decarbonisation Pathway Options

Steel can be manufactured either by the primary BF-BOS (Blast Furnace – Basic Oxygen Steelmaking) or by the secondary EAF (Electric Arc Furnace) route. The primary BF-BOS route accounts for 79% of crude steel production in the UK, and includes coke production, sintering, BF, BOS, casting and rolling. The secondary EAF route accounts for the remainder of UK crude steel production, and includes scrap preparation, electric arc furnaces, casting and rolling. Two-thirds of the sector's energy consumption is used to provide heat (often at very high temperatures over 1000°C), mainly by burning fossil fuels (coal and natural gas) (UK Steel, 2014). The reliance on carbon as a chemical reductant (resulting in significant amounts of process emissions for integrated sites), together with the combustion of fossil fuels, and the indirect emissions from electricity consumption (mainly for EAF sites) make up the iron and steel sector carbon footprint.

There are several incremental options the Iron and Steel industry can currently make towards CO2 emissions reduction. There include improved automation and process control, heat recovery and re-use, biomass-based steam generation, energy management and substitution for low-carbon fuels. However, to meeting the net-zero goals by 2050 sites would generally require a rebuild or retrofit with different technologies in order to transition steelmaking away from the traditional BF-BOS approach. For iron production low-carbon production methods include those described in Table 10, with CCUS being also a potential route.

Table 10. Low-carbon Iron Production Methods

Method	Description
HIsarna	Smelting reduction technology based on bath-smelting, combining coal preheating and partial pyrolysis in a reactor, a melting cone for ore melting and a smelter vessel for final ore reduction and iron production. It requires significantly less coal usage, thereby reducing the amount of CO_2 emissions. This technology is currently being tested at the Ijmuiden steelworks site in the Netherlands
Midrex	Gas-based shaft furnace process that converts iron oxides - in the form of pellets or lump ore - into direct-reduced iron (DRI). It is an innovative ironmaking process that has been specifically developed to produce direct-reduced iron from iron ores and natural gas/hydrogen
Corex	Metallurgical processing carried out in two separate process reactors: the reduction shaft and the melter gasifier. Because coking and sintering plants are not required, and a lower-cost coal compared to the blast furnace route can be used, substantial cost savings can be achieved in the production of hot metal. Corex plant emissions contain only NOx, SO_2, dust, phenols, sulphides, and ammonia in low levels which should be below the maximum values permitted by environmental standards
Finex	Fine iron ore is directly charged at the top of a cascade of fluidized-bed reactors, where it is heated and reduced to DRI by means of a reduction gas derived from the gasification of the coal in the melter gasifier. The DRI fines are processed into hot-compacted iron, transferred in hot condition to a charging bin positioned above the melter gasifier, and then charged into the melter gasifier, where melting takes place. The tapped product—liquid hot metal—is equivalent in quality to the hot metal produced in a blast furnace or Corex plant.

The conversion of iron produced from the technologies included in Table 10 to steel is currently generally undertaken using a Basic Oxygen Steel process which involves the oxidation of impurities. Today, around 70% of global steel production is based on this technology. An alternative complementary process is to use Electric Arc Furnace (EAF). The EAF can be powered solely by reheating furnaces using renewable energy (electricity or hydrogen) to produce the finished product. Flexibility is the main benefit of operating an EAF. While blast furnaces cannot vary their production by much and can remain in operation for years at a time, EAFs can be rapidly started and stopped, allowing the steel mill to vary production according to demand or to take advantage of off-peak electricity pricing.

Full scale CCS for the steel making remains an option that has been conservatively considered in the energy systems modelling scenarios. Although a feasible option for decarbonisation, it may be expected that the steel and iron industry will consider this as a last resource since it would mean retention of coal as a feedstock. While EAF / DRI will impact on the type of product that the steelmaking industry would produce in Port Talbot.

Petroleum Refinery Decarbonisation Pathway Options

Refineries typically consume the equivalent to 7% of their crude oil intake to produce electricity and to supply heating (e.g. as direct-fired heating or indirect heating using steam or a heating medium) required in oil refining processes. Incremental decarbonisation options include energy efficiency improvements associated with improved automation and process control, waste heat recovery or the installation of new Combined Heat and Power Plant (CHP) plant to replace boilers. Post-combustion Carbon Capture and Storage (CCS) of flue gas from CHP plants, hydrogen production plants and Fluid Catalytic Cracking (FCC) flue gases may be considered. However, CCS is dependent on the availability of CO2 transport and storage infrastructure, plus other technoeconomic feasibility consideration such as the ability to install large size gathering ducts and equipment, operation of a post-combustion capture plant and the overall business model (incorporating CO2 emission costs, tax incentives, net avoided emissions, etc.).

Fuel switching to hydrogen is an attractive solution for power and heat generation. Experience exists already in handling hydrogen in the refinery fuel gas system, and hydrogen is recovered and produced for use in hydrogenation processes. Modification of combustion equipment is required, although this does not represent a significant undertaking (limited to replacement of burners, fuel gas valves, and installation of flame monitoring instruments). Currently, some UK refineries are already implementing plans to replace ageing furnaces, boilers or CHP plant with hydrogen-ready equipment, able to combust a range of fuels including 100% hydrogen.

CCS for Petroleum Refineries is considered unlikely since it would mean retrofitting to existing facilities. It is likely that refineries will use hydrogen as the fuel of choice for power generation and process heating.

Chemical Industry Decarbonisation Pathway Options

The chemical industry currently uses natural gas and petroleum fuels to generate process heating in equipment such as fired heaters (direct or indirect) or steam boilers. Currently, the use of natural gas as a feedstock is mostly restricted to the production of fertilisers (natural gas converted to hydrogen via steam methane reforming), methanol synthesis and production of commodity hydrogen.

Options for decarbonisation of the chemical sector include:

- Fuel switching to options such as biomass or hydrogen.
- Feedstock switching to a lower carbon alternative, for example, using biomass gasification.
- Electrification of industrial combustion processes.
- Energy efficiency including waste heat recovery, thermal insulation improvements, heating/cooling process integration, installation of CHP Plants. This would provide incremental gains.
- Implementation of CCUS, particularly focused on the utilisation of CO_2 as a feedstock for the sector.
- Within the Chemical Industry it is likely that process heating will switch to using hydrogen.

Paper Industry Decarbonisation Pathway Options

Papermaking is an energy intensive process which uses electricity to drive the paper machine and heat (from natural gas combustion) to dry the paper from 99% water content to less than 10%. The main options for decarbonisation of the paper sector include:

- Fuel switching, replacing natural gas with low carbon gas (hydrogen, biomethane) to generate process heat.
- Electrification of process heat.
- Energy efficiency including waste heat recovery and CHP for incremental gains.
- Carbon Capture and Storage.

It is considered likely that the Paper Industry will fuel switch to generate process heat.

Cement Industry Decarbonisation Pathway Options

In the cement-making process, raw materials such as limestone (calcium carbonate) with small quantities of other materials (e.g. clay) are heated in a kiln to near 1500ºC to produce clinker, which is then cooled and ground with gypsum and other materials.

The UK cement industry was a first mover in utilising alternative fuels and biomass to replace fossil fuels such as coal and petcoke. Much of the initial move towards such alternative fuels (e.g. tyres, meat and bone meal, processes sewage pellets, wood chips, waste and refuse-derived fuels, etc.) was driven by cheap and abundant availability of alternative fuels. This made them financially attractive compared with fossil fuels, however increasing competition for alternative fuels has raised prices of such fuels and is now proving problematic for the sector.

There are several main options for the cement sector can take towards decarbonisation. With regard to energy usage these include:

- Fuel switching to hydrogen, electricity or biomass.
- Energy efficiency measures (incremental) including waste heat recovery and the use of modern kiln technologies.
- Use of alternative raw materials to improve the energy efficiency of the thermal processes in the kiln, cementitious substitution to reduce the amount of clinker per unit of cement.
- Carbon Capture and Storage.

Cement manufacture uses a large amount of energy and a move away from coal reduces the amount of clinker required to produce cement. Full scale CCS for the Cement Industry would mean retention of coal or petcoke as a feedstock and where it is relatively easy to transport CO2 to a storage location then CCS may be a viable option. In other locations fuel switching may occur.

10.4. WALES AND SOUTH WEST INDUSTRIAL DECARBONISATION PATHWAYS

10.4.1. INDUSTRIAL EMISSIONS REDUCTION

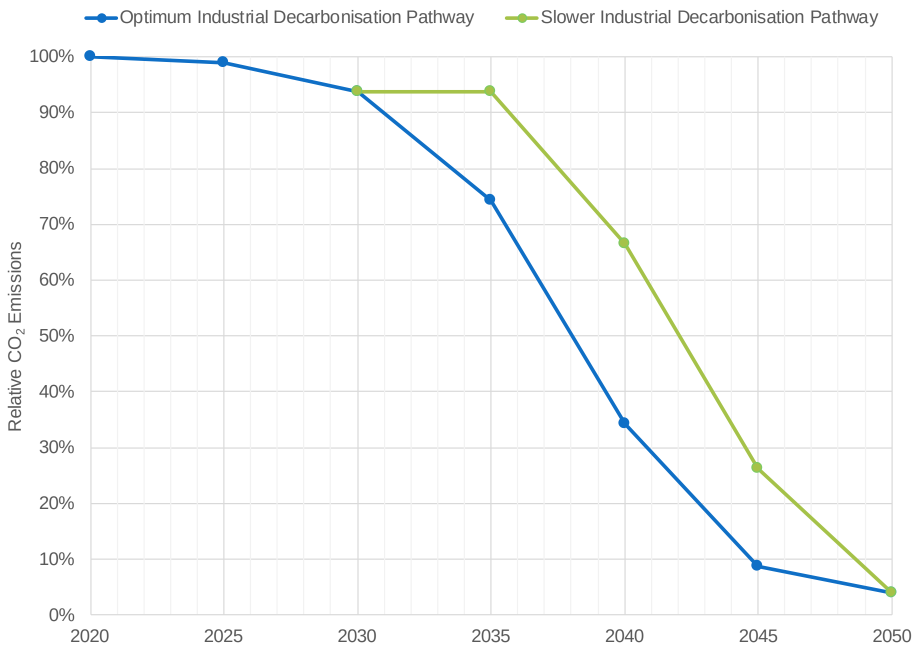
As noted in previous sections, a small number of larger emitters dominate present industrial emissions in Wales and the South West, with the top three industrial emitters in each region contributing by up to 80% of the total industrial emissions. The decisions taken by the major emitters to decarbonise their emissions will have a significant impact on the energy transition solutions deployed in the region.

A potential industrial decarbonisation pathway in the region has been developed based on published and notional plans for the top-10 emitters, see Figure 30. The likely timing and degree of decarbonisation (i.e., CO2 emissions reduction with respect to present day operations) is indicative, and although a degree of uncertainty exists, it represents a credible informed estimate based on actual industrial decarbonisation projects and ambitions at the time of this study.

Two potential pathways have been developed: an optimum pathway based on timely (accelerated) implementation of decarbonisation measures, and a slower pathway where implementation is delayed by a number of years.

Both pathways assume the same decarbonisation end point is reached by 2050. With any residual emitters being decarbonised in the late 2040s, facilitated by the foundational energy system implemented to decarbonise the core SWIC project emissions.

Figure 30 Wales and South West Industrial Decarbonisation Pathways

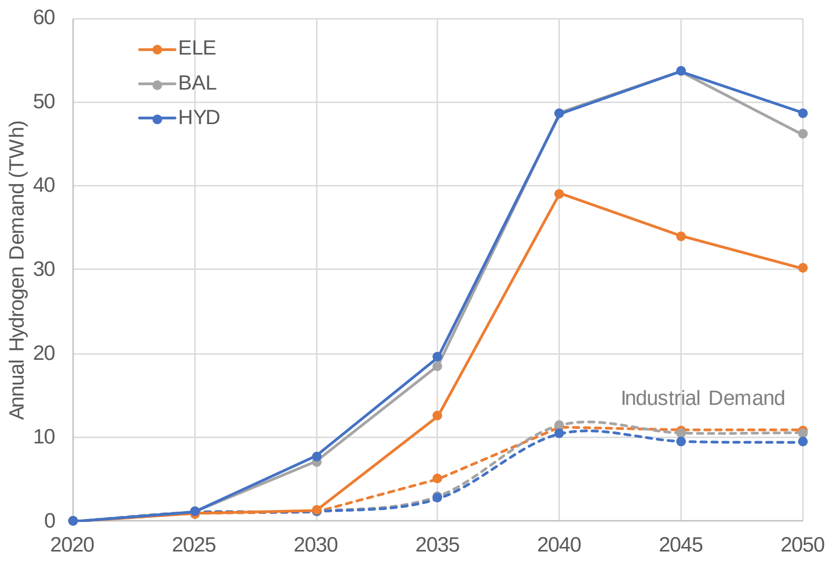


To realise their net zero ambitions for decarbonising industry the UK Government's expectation is that industrial emissions will need to reduce by at least two-thirds by 2035 and by at least 90% by 2050. To meet such a decarbonisation trajectory, it would be necessary to accelerate the presently envisaged project delivery timescales.

10.4.2. INDUSTRIAL HYDROGEN DEMAND

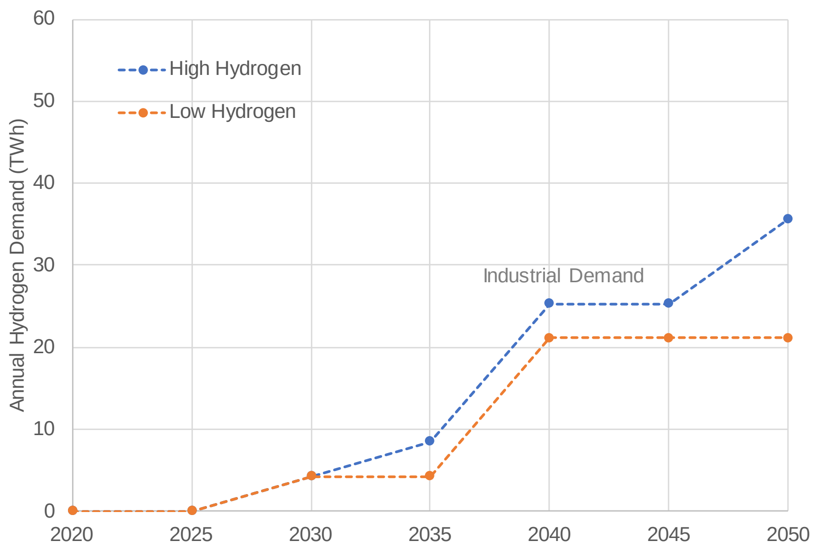
The industry hydrogen demand determined by energy systems modelling has been estimated to be around 10 TWh per annum by 2050, as shown in Figure 31.

Figure 31 Wales and South West Hydrogen Demand – ESME Modelling Assumptions and Outputs



The potential hydrogen demand from industry and its trajectory over time as derived in the Strategic Plan modelling is shown in Figure 32 determined from the knowledge of notional projects, consideration of likely industrial decarbonisation routes in the region and energy demand maintained as per current operations. Figure 32 shows the potential hydrogen annual demand at around 20 TWh by 2050, and potentially reaching a maximum around 35 TWh (assuming DRI for Iron and Steel Industry). These hydrogen demand estimates represent the expected upper limit, which puts in context the likely industrial hydrogen demand as determined by energy systems modelling under the scenarios assumptions.

Figure 32 Wales and South West Maximum Potential Hydrogen Demand – Notional Industry Decarbonisation Projects



11. HYDROGEN TRANSMISSION NETWORK

11.1. OVERVIEW OF GREAT BRITAIN'S GAS NETWORK

Gas is delivered to UK consumers from gas receiving and LNG terminals and pipeline interconnectors through the high-pressure National Transmission System (NTS, see Figure 33) and into the Local Transmission System (LTS) of each network via offtakes from the NTS. The NTS is owned and operated by National Grid Gas, with the LTS regionally operated across Great Britain by the Gas Distribution Network operators (GDNs), Cadent, National Grid, Northern Gas Networks, SGN, Wales & West Utilities.

The NTS spans approximately 7,700 km including 23 compressor stations which deliver gas at pressures ranging from approximately 38 to 94 barg (typically 60 to 70 barg). The network is constructed using steel pipeline and vary in diameter from 450 mm to 1200 mm. The NTS can store approximately 3.8 TWh of natural gas using its line pack storage capacity. The NTS supplies gas to the LTS and the lower pressure distribution networks whilst large industrial users and CCGT power stations connect directly to the NTS.

Natural gas under high pressure (HP) in the LTS is transported around the distribution networks and subsequently reduced to Intermediate Pressure (IP), Medium Pressure (MP) or Low Pressure (LP) via Pressure Reducing Installations. Gas is then delivered to commercial and domestic customers via a network of polyethylene (PE) and metallic LP mains and services. The LTS pipelines operate between 7 and 70 barg, whilst the IP network operates between 2 and 7 barg, the MP between 75 mbarg and 2 barg, and the LP operates below 75 mbar.

Figure 33 GB National Transmission System

Source: National Grid plc.

Existing interconnectors already provide reliable, secure and flexible supply between GB, Norway, the Netherlands and Belgium, enhancing the ability for both sides to adjust supply in response to peaks in demand. GB also acts as a transit country for the supply of natural gas to the island of Ireland.

11.2. SECURITY OF SUPPLY AND NETWORK RESILIENCE

The GB gas system is made up of a diverse range of supply sources (including gas from the UK Continental Shelf received at Gas Terminals, LNG terminals, interconnectors with European Gas Network and biomethane sites) with sufficient capacity to meet the demands of users. Gas supply and demand needs to balance on a daily basis, requiring a flexible system that can respond to demand peaks.

The NTS plays a critical role in terms of security of energy (gas) supply, with the operator having a duty to plan and develop the system in an economic and efficient manner. The Transmission Planning Code (TPC) is part of a suite of documents, which includes Gas Ten Year Statement (GTYS) and Future Energy Scenarios (FES), that describe how the NTS is planned and developed over the long term and how capacity is released to users of the system. Network capability analysis is developed to identify the capability of the NTS to support required flow patterns under the supply and demand forecast scenarios developed from FES and commercial information on capacity bookings.

Peak day forecasts are required under Special Condition A9 (Pipe-Line System Security Standards) of National Grid's NTS Licence to ensure that the network meets defined security of supply requirements. This condition requires the NTS (providing gas transport and storage) to be able to supply the peak aggregate daily demand. The 1-in-20 year peak day demand forecasts are produced by the gas transmission and distribution operators from statistical analysis of historic weather patterns that determine the demand level that is expected to be reached or exceeded (whether on one or more days) on average once in every 20 years.

Network resilience is measured in consideration of a N-1 pipeline system infrastructure design requirement. This means that in the event of a disruption of the single largest infrastructure component, the remaining network infrastructure has sufficient capacity to satisfy the total demand occurring on a 1-in-20 demand day. Network resilience is determined by the ratio of total remaining supplies (after removal of the largest infrastructure) over total 1-in-20 demand, with any result over 100% being acceptable.

Exit capacity gives Gas Distribution Network operators (GDNs) the right to be supplied with gas from the NTS. The GDNs must book and pay for NTS exit capacity in order to be able to offtake gas from the transmission network and serve customer demand. Firm (baseline and incremental i.e., additional above baseline, obligated and non-obligated) and off-peak capacity (available where firm capacity is not being used) are made available at each NTS offtake. Appropriate capacity bookings are critical to ensure security of supply for LTS and gas distribution networks to meet GDNs' 1-in-20 peak demand obligations.

Gas shippers are incentivised to keep the system in balance on a daily basis through a regime that penalises them for over or under supplying. The gas market incentivises sufficient gas to meet peak demand and balancing supply and demand on a daily basis and sufficiently diverse and robust capacity to deliver gas by mechanisms such as storage and supply contracts to guarantee the balance into the future.

The NTS Exit Capacity incentive scheme is aimed to encourage GDNs to minimise the cost of booking sufficient NTS exit capacity. The incentive scheme rewards/penalises GDNs if their NTS exit capacity booking costs are less/more than their NTS exit capacity cost allowances based on forecast volume of bookings set at the time of the price control determination. GDNs aim to optimise capacity bookings by adequate demand forecasting, including booking capacity at cheaper offtakes.

11.3. BRITAIN'S HYDROGEN NETWORK PLAN

Britain's gas network companies have developed a plan to fulfil their commitment to transition the gas networks from transporting, distributing and supplying natural gas to deliver hydrogen instead. The plan (ENA's Gas Goes Green Britain's Hydrogen Network Plan) sets out the projects required to enable 100% hydrogen to be transported and identifies the way to provide sufficient hydrogen production and storage.

The network decarbonisation pathway considers that industrial clusters will drive early dedicated hydrogen production and demand, with initial blending of up to 20 vol% hydrogen into the gas grid from 2023. The Gas Safety (Management) Regulations GS(M)R currently specify a limit in the hydrogen content in gas transported in the network to ≤0.1 vol%, so amendment to the regulation will be required to enable hydrogen blending.

Expansion of hydrogen production capacity and a degree of hydrogen network development (via new hydrogen pipelines and conversion of existing sections of the network) should allow supply of hydrogen to the UK's first 'Hydrogen Town' by 2030.

The hydrogen network plan will be delivered in four broad stages, see Figure 34:

2020-2025 Work developed in preparation for network transition, including the Iron Mains Risk Reduction Programme, completing the safety case, trialling 100% hydrogen for domestic use and carrying out network modelling to ensure that security of supply can be maintained. This first stage will give government the information required to make policy decisions on the conversion of networks.

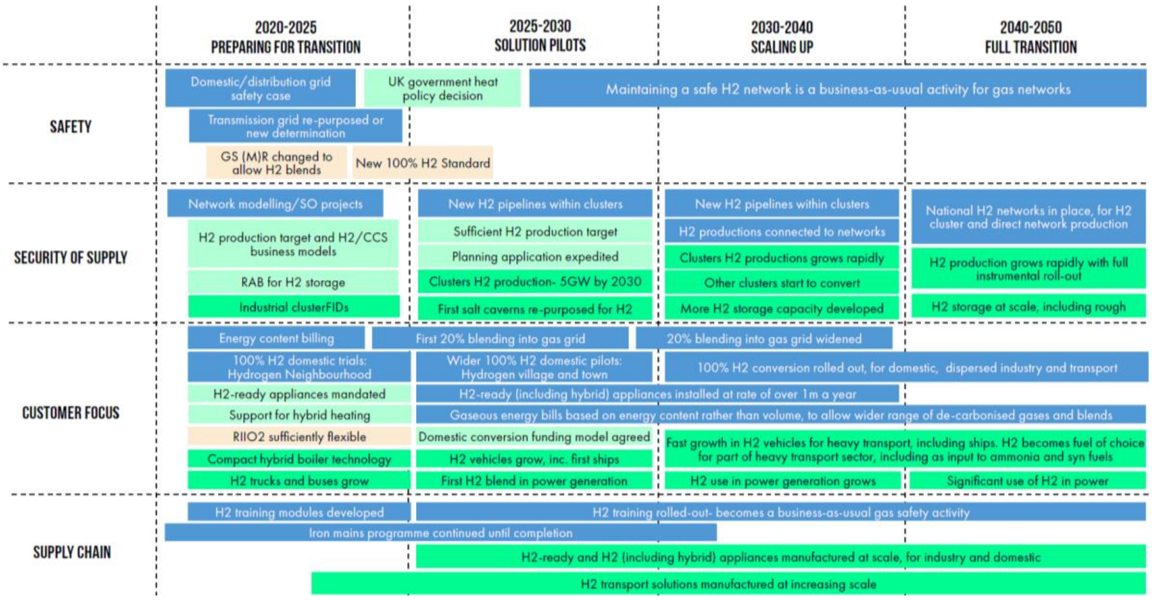
2025-2030 Carry out large demonstration programmes including trials for supply of 100% hydrogen to domestic users at large scale. Hydrogen generation (up to 10 GW, about 3,000 tpd) and supply to industrial clusters via dedicated 100% hydrogen pipelines. Transport of 20 vol% hydrogen blends would be initiated in selected parts of the network. Salt caverns conversion to hydrogen duty initiated to provide storage capacity.

2030-2040 Rapid expansion of clusters' hydrogen production capacity, transport and distribution capacity with growing hydrogen network (new and converted network infrastructure), connecting hydrogen pipelines between industrial clusters, gas network and storage facilities. Iron mains replacement programme complete to allow rolling out 100% hydrogen network conversion for supply to domestic users, transport and reaching industry beyond industrial clusters.

2040-2050 Full network transition, with a national hydrogen network in place supplied from hydrogen production from clusters and dedicated production for network supply.

The hydrogen network plan described above sets out the key milestones for hydrogen availability for wide network transport and distribution. The plan has been used as the basis for a likely WWU network conversion programme in the Conceptual Plan. This considers at high level that hydrogen production will initiate to meet the demand of major industrial users in industrial clusters between 2025-2030, with production capacity and hydrogen network growing significantly in the following decade to allow wider roll out of 100% hydrogen network conversion from 2030-2035 onwards.

Figure 34 ENA Gas Goes Green Britain's Hydrogen Network Plan



Source: Britain's Hydrogen Network Plan Report 2020

11.4. ROLE OF TRANSMISSION SYSTEM IN TRANSITION TO HYDROGEN

It is expected that future hydrogen networks will largely replicate the current configuration (although not necessarily the same geographical topology) of the existing natural gas network. However, the legacy system has been developed based upon natural gas production in the North Sea and gas importation via LNG terminals. There is a huge practical value in the existing pipeline corridors and repurposing pipelines is likely to be far easier than introducing either new pipelines or building new electricity circuits for low carbon energy transfer. Also, some future low carbon gas production locations may be located similar to present day LNG terminals or gas interconnectors with Europe). A hydrogen NTS ("hydrogen backbone", as developed by Project Union) will provide the main transmission infrastructure to transport hydrogen at high pressure and supply which large consumers (e.g. CCGT power plants) and gas distribution networks via offtakes. It has not been considered economic to retain storage capacity within the present day GDN gas network system, due to the inherent storage capability offered by utilisation of linepack within the NTS being considered sufficient to address network requirements. Since this is the basis for present network operations, it is assumed that a hydrogen NTS will similarly be established in future which would be an essential element of a future strategy to provide gas network security of supply. The hydrogen NTS could provide security of supply on a daily basis by becoming a resilient supply with high availability to meet 1-in-20 peak hydrogen flows.

It is expected that a hydrogen LTS will also be developed as required to support conversion of the IP, MP and LP gas distribution network.

It is anticipated that security of supply will be supported by the injection of blue and green hydrogen into the hydrogen NTS from multiple sources, including clustered hydrogen production plants (e.g. at Milford Haven due to the site being an existing location of natural gas importation at scale) and interconnectors to the European gas or hydrogen network infrastructure. It is anticipated that a hydrogen NTS will also help manage seasonal variations in hydrogen demand by connecting with underground gas storage sites.

Network resilience will be provided by system capacity expansion (particularly in regard to storage) in consideration of potentially larger volumes of hydrogen compared to current volumetric flows of natural gas. The required additional network infrastructure (entry points, pipelines, offtakes, pressure reduction installations, buffer storage and equipment such as compressors) would have to be installed with an appropriate capacity to ensure the 1-in-20 peak hydrogen demands can continue to be met.

Currently, diurnal variability in gas demand by the users connected to the gas network (either Temperature Sensitive Load i.e. heat or Industrial demand) can be predicted by daily demand forecast scenarios and the expected variation in a day, such that supply capacity and variations can be handled by firm and flexible offtake capacity bookings and line pack storage. From the perspective of WWU as gas distribution network operator, the NTS supply is treated as a reliable source of gas which provides security of supply, on the basis of appropriate capacity bookings.

It is assumed that a similar 1-in-20 peak flow design requirement will be applied when considering provision of security of supply in a future low carbon / hydrogen based gas network system. As a result, it is therefore assumed that security of supply would have to be provided in a similar manner as per the current operating model to provide a robust supply source with high availability. It is therefore assumed that any additional storage would be via line packing due to new network infrastructure or additional physical storage in a similar way to current operation by flexible capacity bookings, in this case from the hydrogen supply source (e.g. a hydrogen NTS).

For current natural gas supply, seasonal demand variations in the region rely on NTS supplies, which are provided by LNG supplies.

The BEIS report Gas Security of Supply: A Strategic Assessment of Great Britain's Security of Supply (2017) reported that the strength of the gas system is built on supply diversity, with the system being resilient to multiple infrastructure failures: up to 70% of supply infrastructure would need to fail before supplies to domestic gas customers would be interrupted. The report indicated that there is currently spare capacity on the gas system. Britain's Hydrogen Network Plan includes a commitment to deliver a hydrogen network that meets the same high levels of supply security as today, with very rare unplanned interruptions. This includes ensuring:

- Sufficient physical network capacity and resilience to meet demand peaks
- Effective System Operation
- Linkages to sufficient hydrogen production and storage capacity
- Flexibility to connect new sources at more entry points.

A critical element of the NTS role in the transition to hydrogen is the (yet to be developed) transition plan to convert existing pipelines and/or install new pipelines for hydrogen service. This is likely to be achieved one (or perhaps a combination) of the following options as the UK transitions beyond an initial 20 vol% content blend in the NTS:

- Operation of parallel pipeline systems supplying natural gas and 100% hydrogen independently; and/or
- Increasing percentages of hydrogen blends within the existing NTS pipeline system, with deblending technology utilised to manage the percentages of hydrogen and natural gas supplied to consumers.

Based upon recent engagement with National Grid Gas Transmission, it is presently understood that the transition to a hydrogen NTS will generally be achieved by the progressive operation of parallel pipeline systems due to the availability of multiple parallel pipelines across much of the UK and the anticipated costs of implementing deblending solutions.

There are fewer radial NTS feeders running across WWU's region and therefore to realise parallel supplies of both hydrogen and natural gas, either localised blending (and potentially also deblending) facilities may be required. Otherwise, additional feeders would need to be installed. Particularly in areas where initial hydrogen production hubs are also likely to be located and parallel hydrogen and natural gas pipelines could be required to support the transition to a future hydrogen network, e.g. between Milford Haven and Felindre (near Swansea) in South Wales.

The alternative option to support network transition beyond national gas transmission plans, is for the regional development of (blue) hydrogen supply and (industrial cluster) demand to drive the development of a hydrogen LTS system linking hydrogen production with the gas distribution network. For the case of South Wales, this would be a hydrogen pipeline linking hydrogen production in Milford Haven with the local gas network at the Dyffryn NTS offtake and potentially linking industrial clusters at Port Talbot and beyond.

11.5. ROLE OF GAS NETWORK TO MANAGE RENEWABLES INTERMITTENCY

There are plans to install a lot more renewable power generation from wind (especially offshore wind) compared to present day, and also to ramp up the electricity demand. Government plans by 2030 consider the production of 50 GW of offshore wind, including 5 GW of floating offshore wind. Over half the renewable generation capacity will be wind. This will provide enough wind capacity to power every home in Britain.

With offshore wind still only forecasting a load factor of around 60% and not dissimilar variability in output, there is not yet a clear view in how the electricity system is intended will be configured and operated to instantaneously balance supply and demand in the future when offshore wind is projected to become the predominant source of produced electricity.

It is anticipated that there will be a limit to the amount of demand side management that could effectively be deployed at the consumer level, especially if peak electricity demand continues to be largely coincident with rush hour (e.g. if future consumption continues to follow present trends).

The historical use of dispatchable power generation has allowed the Great Britain's electricity transmission and distribution systems to be optimised based upon being able to supply peak demand. Unless it is possible to entirely match electricity demand to available renewable energy production on an instantaneous and continual basis using demand management techniques, transitioning to an electricity system which has intermittent renewable generation as its primary source of power will require additional electrical infrastructure to provide additional electricity transmission and energy storage capacity.

In practice, there is likely to be a limit to the extent that demand side management techniques can be applied to modify present electricity system demand, e.g. inter-seasonal demand profiles and winter peak demand. Therefore, additional electrical infrastructure to provide additional electricity transmission and energy storage capacity will almost certainly be required. This has been demonstrated by National Grid ESO in their latest Operability Strategy Report 2022 forecasting that the cost of the additional infrastructure will be up to £16 billion over the next 20 years because renewable generation has a lower load factor than conventional generation sources and is located remote from demand centres.

Comprehensive consideration of anticipated energy production and demand profiles will be necessary to forecast the anticipated cost of such a solution and whether implementing the associated electricity system would be feasible within required timescales from both corridor routeing and planning perspectives.

At present, electricity systems security of supply and storage and management of the intermittency of renewables in the UK is predominantly provided via the gas network and the flexible operation of CCGT power generation, supplemented by electrical interconnection with Europe. A hydrogen-based gas network could readily provide similar functionality and provide indigenous based security of supply, with hydrogen combustion in power generation presently being considered across multiple industrial clusters.

Hydrogen therefore potentially presents the most feasible means of providing the UK with long duration, inter-seasonal energy storage at transmission (i.e. TWh) and also national scale.

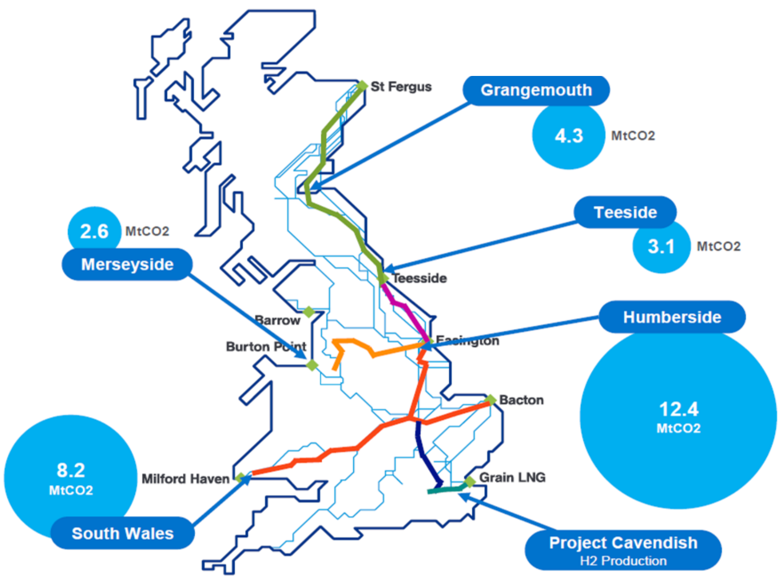
11.6. GREAT BRITAIN'S HYDROGEN BACKBONE

The transition to a hydrogen network will change the configuration of the NTS. The UK ENA 'Gas Goes Green' Hydrogen Network Plan network strategy on hydrogen considers the initial transport of gas blends with a maximum hydrogen content of 20 vol% as enabler for the transport of 100% hydrogen (as part of FutureGrid project), followed by conversion of sections of the NTS for hydrogen service where multiple parallel pipelines exist.

Whilst the current NTS is used to carry gas from various entry points around the coastline (see Figure 33), it is anticipated that hydrogen supply will be sourced from the hydrogen produced near to the industrial clusters. Anchor projects in the industrial cluster will initiate hydrogen production linked to a baseload hydrogen demand, driving the hydrogen generation capacity which will expand to allow injection of hydrogen in the gas network in the longer term.

A new hydrogen backbone (see Figure 35) has been proposed by National Grid for Great Britain and developed as part of Project Union. This hydrogen backbone is in line with European plans (consortium consists of Enagás, Energinet, Fluxys, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, and Teréga) for a similar configuration for hydrogen transport and distribution (https://guidehouse.com/-/media/www/site/downloads/energy/2020/gh_european-hydrogen-backbone_report.pdf). The hydrogen backbone will connect the clusters of Grangemouth, Teesside and Humberside, the North West and South Wales industrial clusters.

Figure 35 Indicative Structure of Proposed Hydrogen Backbone



Source: HyNTS Project Union

The hydrogen backbone will operate as a hydrogen NTS supplying hydrogen at high pressure, linking sources of hydrogen (blue and green hydrogen generation plants, underground gas storage and interconnections to the European hydrogen backbone) and allowing offtake of hydrogen by large industrial users (including power generation) and by LTS and gas distribution networks transporting hydrogen.

The European Hydrogen Backbone considers 6,800 km of hydrogen pipeline by 2030 and 22,900 km by 2040, consisting of approximately 75% retrofitted existing infrastructure and 25% of new hydrogen pipelines. National Grid's Project Union will review the potential phased repurposing of approximately 2,000 km of existing NTS assets corresponding to about 25% of the current NTS infrastructure to transport hydrogen as part of the hydrogen backbone by 2030.

New hydrogen transmission pipelines will also be developed and linked to the hydrogen backbone. The HyNet project is currently developing plans for a 70 km hydrogen LTS (600 mm NB) within the North West of England, whilst 250 km of new and/or repurposed LTS network is under study in the North East.

National Grid anticipates the UK hydrogen backbone could carry at least a quarter of the current gas demand in Great Britain and provide vital resilience and storage as per current NTS operations.

Project Union will explore how to convert pipelines in a phased approach, identify pipeline routes, assess the readiness of existing gas assets and determine a transition plan for assets in line with net zero plans. National Grid have advised that first results from a model of the NTS converted to hydrogen demonstrate that the current infrastructure can carry the required volumes of hydrogen in 2050.

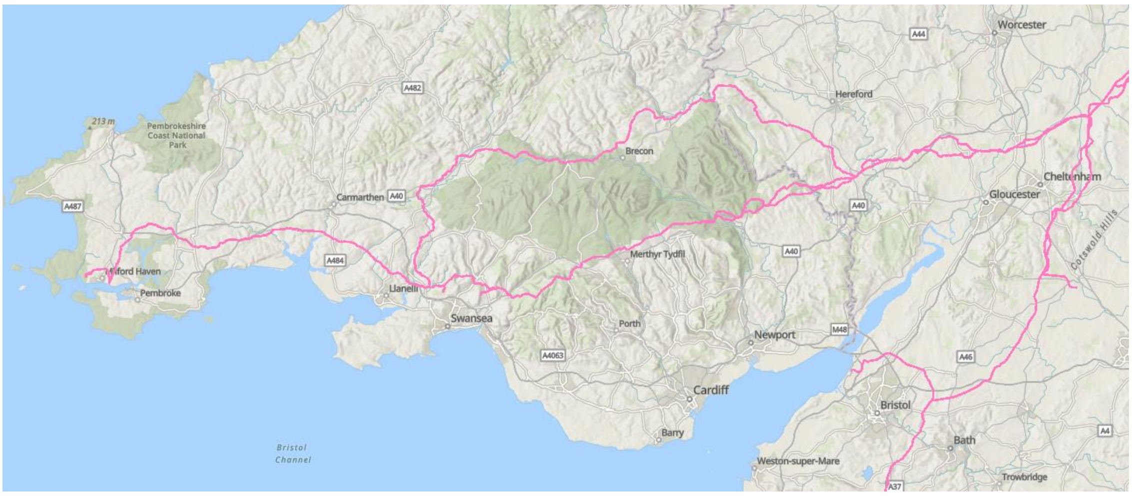
Connection to existing interconnectors at Bacton and Project Cavendish at Isle of Grain are considered to be key for the proposed hydrogen backbone plans, allowing connection with the European Hydrogen Backbone.

Project Union will also look at how to connect the backbone to the existing interconnectors at the Bacton gas terminal, which would link the UK and European hydrogen networks and open up potential future import and export of hydrogen with European neighbours. A link to at Isle of Grain, where National Grid's Project Cavendish is investigating its potential as a location for hydrogen production and storage, is another key component.

With its greater import capacity (currently for LNG, with significant potential for blue hydrogen production) and its strategic role within the South Wales Industrial Cluster, Milford Haven is arguably as important as Isle of Grain to the development of the hydrogen backbone from the hydrogen supply point of view.

Assuming that LNG imports will be retained or replaced by importation of green gas (e.g. in the form of ammonia) to provide the energy mix as per our present-day security of supply policy, and on the basis that most of this will be converted to blue hydrogen, a dedicated hydrogen transmission pipeline would need to be available to export hydrogen to South Wales and to England (see Figure 35). This section could be made of conversion of the existing NTS pipelines or installation of a new dedicated hydrogen transmission pipeline, likely to follow existing NTS pipeline routes (see Figure 36). For North Wales and the South West, conversion of the existing NTS to hydrogen service will be based on Project Union's plans (see Figure 35).

Figure 36 NTS Configuration in South Wales



Source: National Grid plc

The initial topology of the hydrogen backbone will be based on the hydrogen transport capacity that can be made available while continuing to enable natural gas transport in parallel, although in gradually decreasing quantities. This has been the approach used in the development of the European Hydrogen backbone, where spare capacity from parallel pipeline routes has been identified and committed to a potential conversion.

The natural gas grid will remain operational to transport natural gas used as feedstock in blue hydrogen production, decreasing volumes of natural gas used mainly in heat and power generation whilst allowing the transport of increasing quantities of biomethane.

In South Wales, the scope for the development of the hydrogen backbone whilst retaining some capacity for transmission of natural gas could be limited due to the single pipeline from Herbrandston to Felindre. A new regional HP hydrogen transmission system would be required to allow supply of natural gas from Milford Haven to be retained (to continue to provide security of supply to natural gas operations) while also in parallel developing a parallel hydrogen supply networks. The natural gas pipeline would eventually convert to hydrogen when sufficient hydrogen production capacity is developed, and the pipeline is no longer needed to supply natural gas as part of the overall UK energy transition process to reach net zero.

In consideration of significant industrial demand from South Wales, regional blue hydrogen generation hubs may operate, particularly in Port Talbot. Then a regional HP hydrogen transmission pipeline could be developed to link these areas of industrial demand. The HP hydrogen transmission system will also allow reaching the wider user demand supplied from the gas distribution network, with hydrogen being injected to supply this initially as gas blends and during the network transition period (from 2030 onwards).

In North Wales, the potential to develop a hydrogen backbone whilst retaining some capacity for transmission of natural gas is also limited due to the single pipeline feeding the Maelor Offtake. However, this offtake does benefit in being in relatively close proximity to the HyNet Project at Stanlow. A regional transmission system will be required to retain supplies of both blue hydrogen and natural gas. In the South West, the potential to develop a hydrogen backbone whilst retaining some capacity for transmission of natural gas is also limited due to the single pipeline beyond Kenn. A regional transmission system will be required to retain supplies of blue hydrogen and natural gas.

12. CURRENT ELECTRICITY NETWORK CONSTRAINTS

12.1. INTRODUCTION

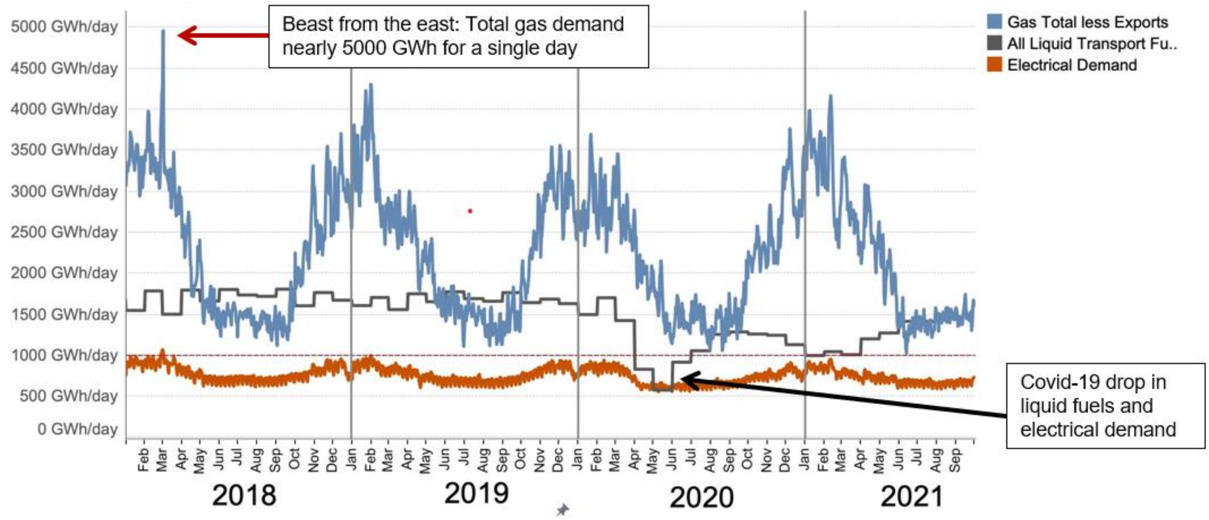
Although the focus of the present study work being delivered to WWU is the future gas network in Wales and the South West, some 40% of the UK's energy consumption in 2019 was in the form of petroleum based products – largely associated with the transport industry.

With the UK Government's Clean Growth Strategy recognising electricity and hydrogen as the two primary decarbonisation pathways available, the challenge in realising a UK net zero energy system by 2050 is not only to decarbonise the existing electricity and gas networks, but to also transition present day petroleum demand to lower carbon end-use – whether by using electricity and/or hydrogen vectors.

To identify a feasible (as well as hopefully somewhat optimal) solution to deliver net zero across the UK and in particular in Wales and the South West of England by 2050, it is necessary to take a holistic energy transition perspective considering whole energy system design and also its operations.

To adequately understand how to begin to understand this question, it is important to first understand what the future energy demand might look like: the energy demand profiles for present end-use vectors are not the same. Although annual the end-use energy demand for gas was less than double that for electricity, the peak demand for gas in 2019 was around five times the peak electricity demand. With the maximum increase in heat demand between 5am and 8am in 2017 and 2018 around ten times the highest corresponding electricity demand increase. The gas grid therefore presently offers significantly greater energy transfer capacity and ramp rate compared with the electricity system.

Figure 37 UK Energy Demand Profiles (By Fuel Type)



Source: Grant Wilson. Energy Informatics Group. Birmingham Energy Institute. University of Birmingham. Underlying data from National Grid, Elexon and BEIS

Conversion factors need to be taken into account when considering alternative end-use vectors. However, at a high level the energy demand profiles presented in

Figure 37 indicate that the high seasonal variation in heat demand would be more likely to require installation of network infrastructure which risks being underutilised for much of the year if transferred onto the electricity system compared with transport demand which is much more constant throughout the year. While an order of magnitude increase on the present electricity system infrastructure capacity could be required to support decarbonisation of either heat or transport demand alone (even after conversion factors for electrification-based technologies have been taken into account).

To unlock value from the UK's energy systems as a whole, it is therefore important to understand both the capability of each network and also the likely impact of transferring each different type of energy demand. If the most feasible way of providing inter-seasonal energy storage in future remains in the form of fuel (as at present), then the optimal solution for heat decarbonisation may be via conversion of the present gas grid to hydrogen use.

Details on the electricity transmission system capacity and constraints are presented in National Grid ESO's Electronic Ten-Year Statement (ETYS) document which is published annually. National Grid ESO has defined a number of system boundaries across the GB electricity transmission system to describe the ability to transfer power between different regions across the country. Assessment of the electricity system capacity and constraints across WWU's area of operations and therefore the potential for these constraints to drive hydrogen rather than electricity based solutions is provided in the sections below.

12.2. WALES

The electricity transmission grids in Wales comprise geographically separate infrastructure in North and South Wales, which is only interconnected via England. See Figure 38.

Figure 38 Welsh Electrical Transmission Grid

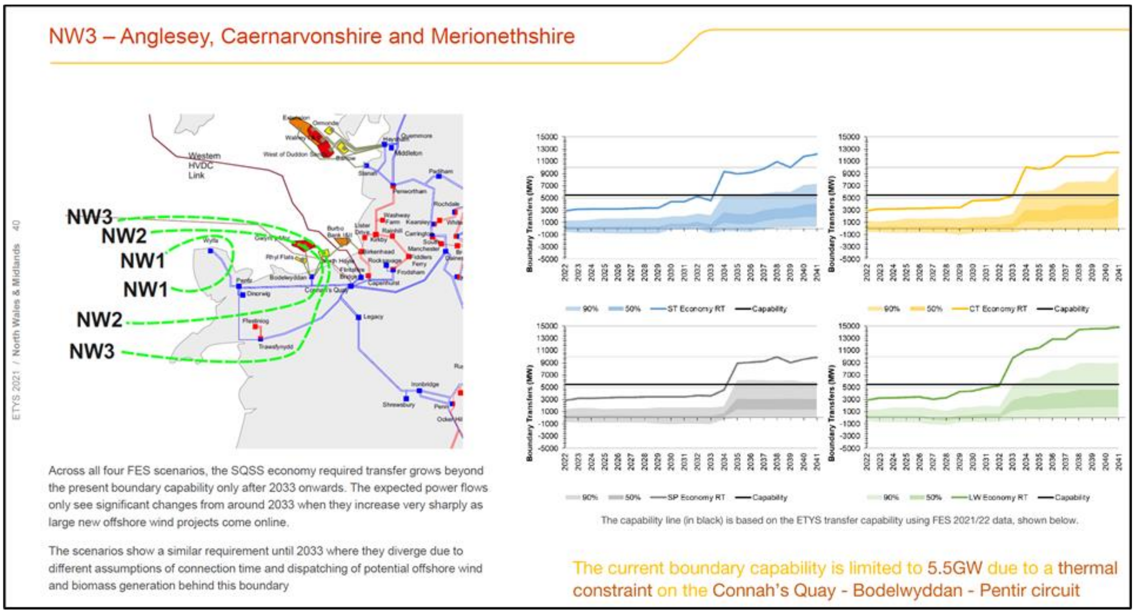
Source: National Grid plc

Constraint and capacity information from the ETYS 2021 report for North and South Wales is presented in Figure 39 and Figure 40 below, denoted as the NW3 and SW1 boundaries respectively. The power transfer capacity in North and South Wales is 5.5 GW and 2.9 GW respectively. The required transmission system boundary capacity is a function of the generation and demand within the region and therefore the required export and/or import capacity across the boundary.

In contrast, the LNG terminals in Milford Haven are able to import up to 40% of the UK's gas demand at maximum send-out rate, around 317 TWh per annum, equivalent to approximately 36 GW every hour. For context, the total gas demand in South Wales detailed in the BEIS sub-national data for 2019 was 18.3 TWh – indicating the extent that the region also exports energy to the rest of the UK.

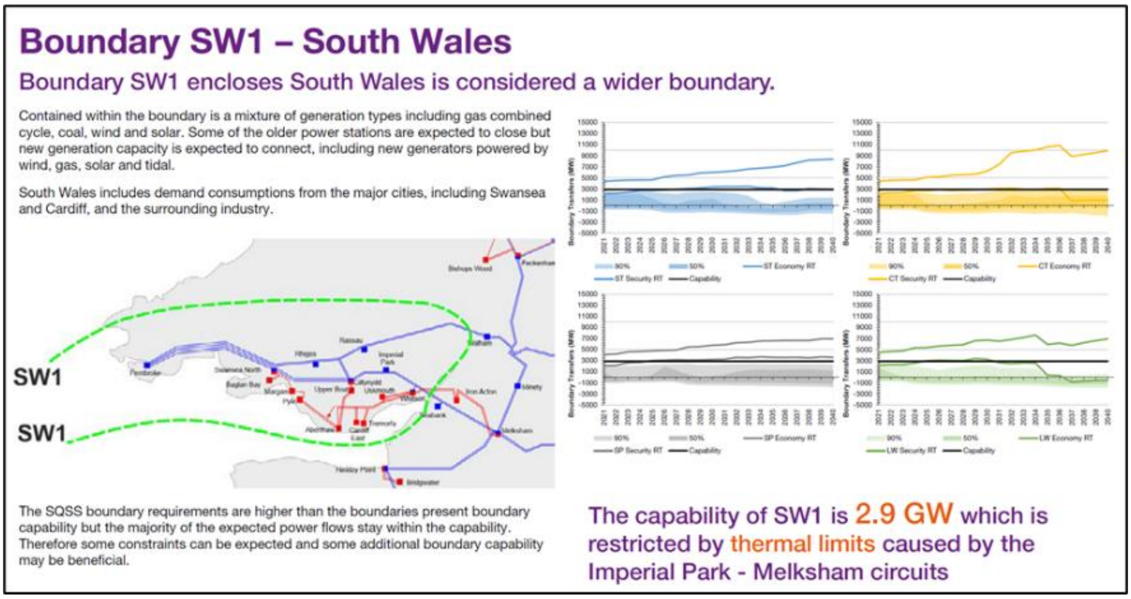
Lack of capacity on the distribution system could also present a limitation to the ability to transfer other end-use energy demand, whether in the form of heat and/or transport, onto the electricity system. Although this potential electricity system constraint has not been analysed to any significant extent in this report.

Figure 39 North Wales Transmission System Capacity and Constraints (ETYS 2021)



Source: National Grid plc

Figure 40 South Wales Transmission System Capacity and Constraints (ETYS 2020)

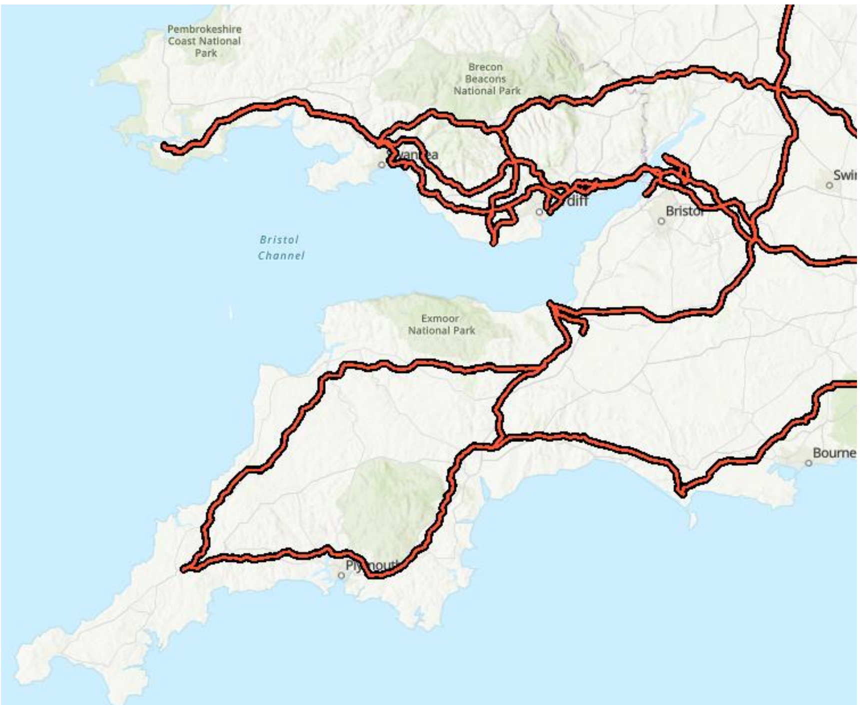


Source: National Grid plc

12.3. SOUTH WEST

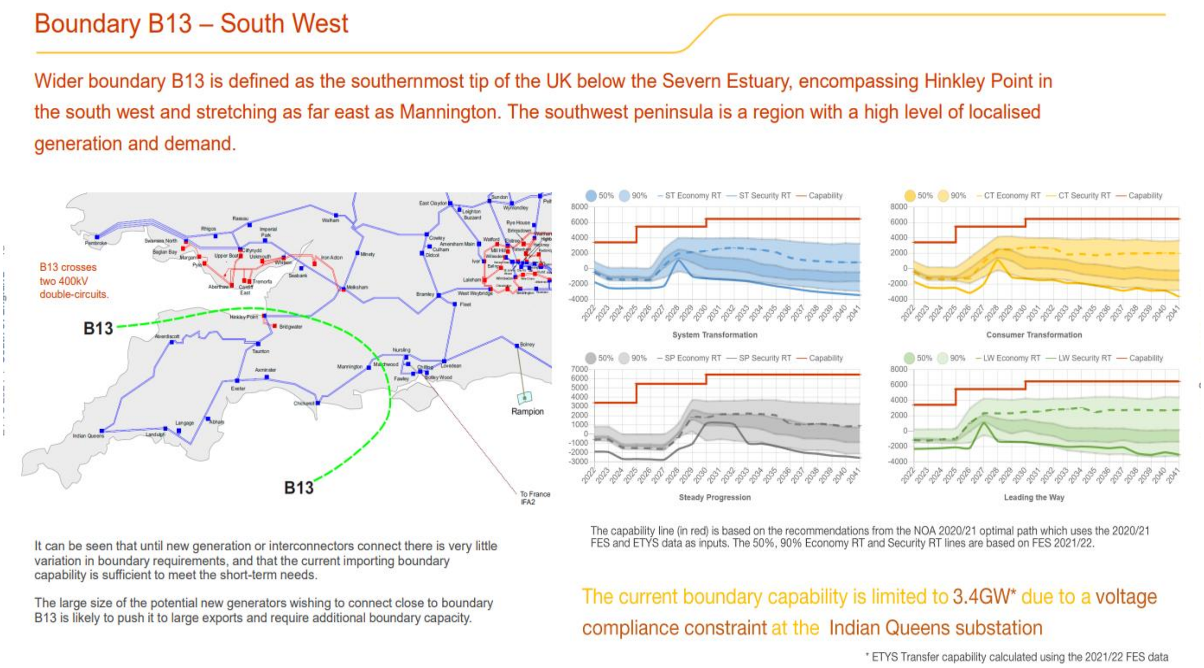
The electricity transmission grids in the South West is interconnected with Wales, the Midlands and to South East England. See Figure 41.

Figure 41 South West Electrical Transmission Grid



Source: National Grid plc

Figure 42 South West Transmission System Capacity and Constraints (ETYS 2021)



Source: National Grid plc

Constraint and capacity information from the ETYS 2021 report for South West is presented in Figure 42, denoted as the B13 and SW1 boundaries respectively. The power transfer capacity of 3.4 GW is due to constraints at Indian Queens.

12.4. FUTURE ELECTRICITY SYSTEM CAPACITY REQUIREMENTS

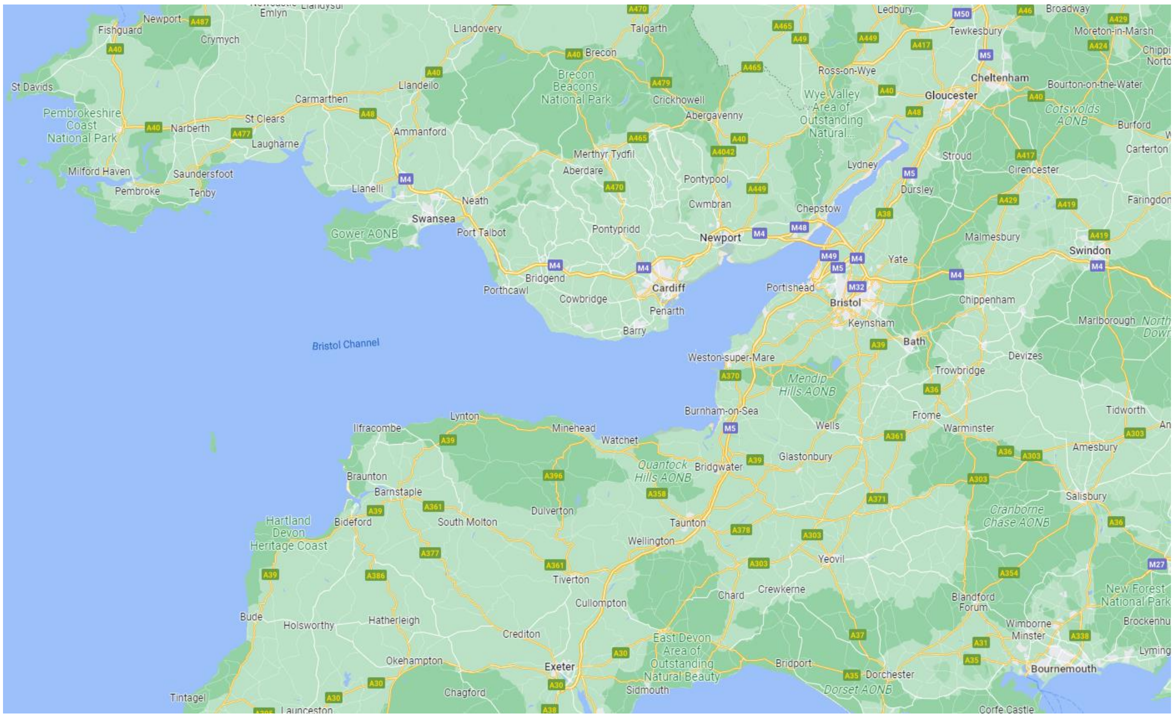
There is potential for the Wales and South West of England region to generate significantly more electricity in the future than at present.

In late 2021, the Crown Estate published further details on its plans for floating wind leasing in the Celtic Sea, confirming its ambition to unlock up to 4GW of new clean energy capacity in England and Wales. While the Celtic Sea Cluster envisages that the area of ocean situated off the coast of Cornwall, between Wales and Ireland could support floating wind projects which would provide between 15 and 50GW of the 150-250 GW total floating offshore wind capacity that they consider could realistically be developed in the Celtic Sea.

These projected offshore wind capacities are significantly in excess of the present electricity transmission system transfer capacity. Even if present electricity demand levels in the region were to be significantly increased to deliver net zero regionally, to realise the potential for energy production in the Celtic Sea would require an order of magnitude increase in the electricity export capacity from Wales and the South West regions to the rest of the UK.

However, as shown in Figure 43 there are a number of National Parks and designated Areas of Outstanding Natural Beauty (AONB) located through the region which will make the development of new electricity transmission corridors a challenge since any such proposals are likely to be controversial and attract significant negative public opinion. No new pylon circuits are considered by NG ESO for the Wales or South Wales of England boundaries in their ETYS documentation before 2030. (The extent of the latest projections).

Figure 43 National Parks and AONBs (South Wales and South West)



Source: Google Maps

The levels of energy production which could be realise with offshore wind in the Celtic Sea would be likely to also present a capacity challenge to the gas network if converted to hydrogen.

However, as shown above, significantly higher energy transfer capacity can be provided by a pipeline compared with an overhead line, while also being less visually and environmentally intrusive once in operation.

Very few new overhead lines have been constructed in the UK over the last two decades. One of the few that have, the Beauly-Denny line in Scotland considered the upgrade of an existing line voltage from 275 kV to 400 kV (requiring higher pylon towers) rather than the installation of a brand-new line. However, from the initial design concept, implementation of the project took around a decade and a public inquiry before the line upgrade became operational. It is therefore essential that such practical considerations be taken into account to ensure that a realistic perspective is developed on the ability to create increased energy system capacity across either the electricity or gas networks by 2050.

13. HYDROGEN PRODUCTION LOCATIONS

13.1. CO-LOCATED PRODUCTION AND DEMAND

Hydrogen production could be located next to or near the point of use to minimise the scope and cost associated to pipelines to transport hydrogen to the point of use.

Local generation of blue or green hydrogen at scale could be adequate for supply to a single industrial user, which is the case of anchor projects around industrial clusters. For this case, unavailability of the hydrogen production plant could be accommodated within the site operational philosophy.

Local hydrogen generation could also be feasible from small-scale electrolysis e.g. from a local solar array or wind farm or from small scale SMR from biogas which could feed hydrogen to a dedicated user (e.g. a gas engine) or even inject hydrogen into the LTS.

In consideration of security of supply considerations, hydrogen from small-scale local generation delivered to the gas distribution network would be supplementary to the main hydrogen supply, like the current case of biomethane injection into the gas network.

It is unlikely that a single local source of hydrogen would be accepted as a reliable supply for a wide gas network supplying multiple users across a region of the UK. The major challenge associated with co-locating hydrogen production with demand supplied from a gas distribution network relates to security of supply as discussed in Section 11.2. A local plant supplying hydrogen to a region will not provide a highly resilient source and the ability to flexibly operate over the range of daily demand flows (likely to be in the range 10-100% of peak demand for gas distribution network) without significant buffer storage.

13.2. CENTRALISED PRODUCTION AT SCALE AND DISTRIBUTION

13.2.1. HYDROGEN PRODUCTION AT INDUSTRIAL CLUSTERS

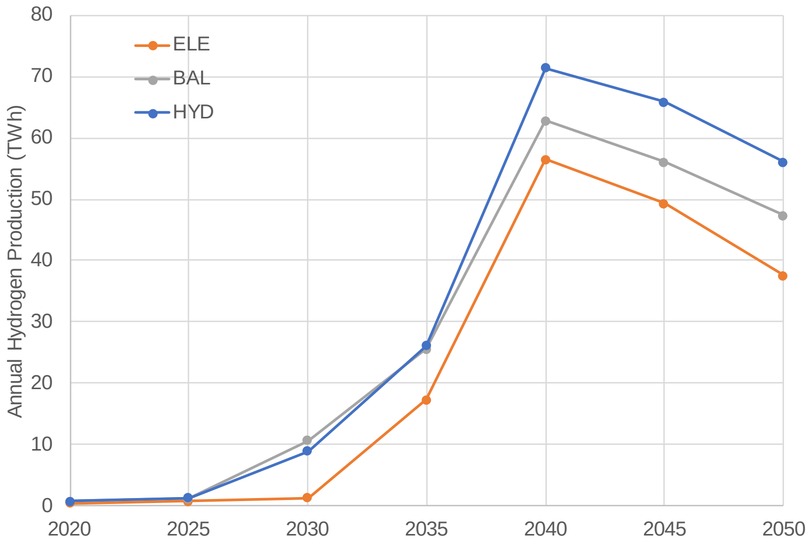
Although co-located energy production and demand was the approach followed in developing the original electricity and gas networks, over time the design basis gravitated towards more centralised production of energy at scale, which is then transported and distributed to the areas of demand.

From the point of view of hydrogen supply, establishing locations where hydrogen can be produced at scale is key to realise the transition to a low carbon gas network. The location of early hydrogen production anchor projects is closely related to the place of consumption in industrial clusters. The hydrogen generation capacity in these sites will increase in phases to support gradual decarbonisation in industrial clusters.

The gas networks will be supplied from industrial clusters once sufficient and reliable production capacity is achieved, with hydrogen being initially injected to produce gas blends in the transition to 100% hydrogen. Therefore, hydrogen production must be expanded beyond the level that is needed for use within clusters to allow a widespread gas network conversion to take place from 2030. The Hydrogen Network plan estimates that about 10 GW of low-carbon hydrogen (green or blue) is expected to be required by 2030 to minimise the risk of insufficient volumes of hydrogen being produced.

Hydrogen production in Wales and South West, determined from the energy systems modelling presented in the Strategic Plan is shown in Figure 44. Hydrogen production peak is around 70 TWh by 2040 for the high hydrogen scenario (reduction in subsequent years attributed to energy efficiency measures). This is equivalent to an average hydrogen production capacity of about 5,000 tpd.

Figure 44 Wales and South West Hydrogen Production – ESME Modelling Assumptions and Outputs



Blue hydrogen can deliver the required scale. Blue hydrogen production can deliver more hydrogen in a shorter timeframe than green hydrogen generation, requiring capacity additions each year. Ensuring that CCS infrastructure supporting blue hydrogen production is developed at scale in several clusters by 2030 is critical to facilitate network conversion to hydrogen.

Over time (by 2040-2050), it is expected that green hydrogen will become the production method of choice as production costs decline and development of a hydrogen NTS with storage capability supports management of more intermittent production.

Bioenergy (biomass gasification) with CCS (BECCS) is a potential method of hydrogen production delivering negative emissions, and for this reason, BECCS has been used as the production method with priority in energy systems modelling scenarios. The key enabler for hydrogen production is the ability to deploy with CCS, together with the availability of biomass supply in consideration of potential competing uses. Due to this, the contribution of BECCS to hydrogen production is limited and supplementing baseload production of blue hydrogen in early years and green hydrogen beyond 2040.

Hydrogen production from advanced nuclear reactors able to switch between electricity and hydrogen production modes is another feasible production method considered in energy systems modelling scenarios. The contribution of this method may be constrained by the existence of nuclear power generation projects near gas transmission infrastructure, the significantly large capital costs associated and the relatively long project execution duration.

13.2.2. HYDROGEN TRANSMISSION INFRASTRUCTURE

Centralised production of hydrogen at scale will be accompanied by the development of a hydrogen transmission system, which will enable supply to consumers (domestic, commercial, industrial and transport) via the gas distribution network. The hydrogen transmission system will consist of the hydrogen backbone pipelines being part of a wider hydrogen NTS that will connect all regions in Great Britain to access multiple hydrogen supply sources, underground storage and will supply gas distribution networks.

The future hydrogen NTS will play a critical role in terms of security of supply as discussed in Section 11.2 and 11.4, ensuring that the network reliability is achieved by:

1. A variety of sources with substantial aggregated capacity;
2. Infrastructure sized to handle peak flows and configured to operate in a flexible way;
3. The provision of adequate buffer storage in the form of line pack and access to large scale (underground) storage; and
4. Accurate demand forecasting to inform network operation and infrastructure planning.

Multiple sources will provide the required reliability to guarantee security of supply, including not only hydrogen production plants but also the access to supply via interconnectors with the European Hydrogen Backbone and with underground gas storage to meet seasonal demand variations.

In consideration of the current key role of LNG imports to Milford Haven within Great Britain's energy security of supply, the South Wales region would be expected to deliver blue hydrogen from LNG for regional distribution in South Wales and exported via the hydrogen backbone to England. The main supply of hydrogen to North Wales and the South West will from the hydrogen NTS from multiple sources.

It is expected that a hydrogen LTS will also be developed as required to support conversion of the IP, MP and LP gas distribution network. Hydrogen supplies to the LTS are assumed to be sourced from a hydrogen NTS as per current practice for the supply of natural gas.

13.3. POTENTIAL LOCATIONS FOR BLUE HYDROGEN PRODUCTION

It is generally expected that the location of the hydrogen production will be primary dictated by vicinity to the primary energy sources. For the case of blue hydrogen production, location will generally be dependent on the availability of natural gas feedstock. A dedicated natural gas supply would have to be provided up to the point of use by the blue hydrogen plant. Also, export routes for captured CO_2 including intermediate storage and transportation of CO_2 in gaseous, dense phase or liquefied form would be required and contribute to the selection of the blue hydrogen plant location. For the case of green hydrogen, the location of the generation plant is generally expected to be close to the renewable power generation and electricity transmission infrastructure.

The WWU supply area has been assessed using GIS tools to identify potentially suitable locations for blue hydrogen production. Suitability is based on a number of criteria, including:

- Distance from NTS Offtakes (for natural gas feedstock supply at scale)
- Distance from coast and/or specific port (for export of CO_2 by ship)
- Proximity to COMAH sites (for plant location and access to industrial users)

The scoring for the selection criteria was overlaid to arrive at a cumulative score with red being non preferred and green preferred.

Figure 45 and Figure 46 show the heat maps for the WWU supply area highlighting blue hydrogen production locations with more potential.

Figure 45 Potential Blue Hydrogen Production Locations - Wales

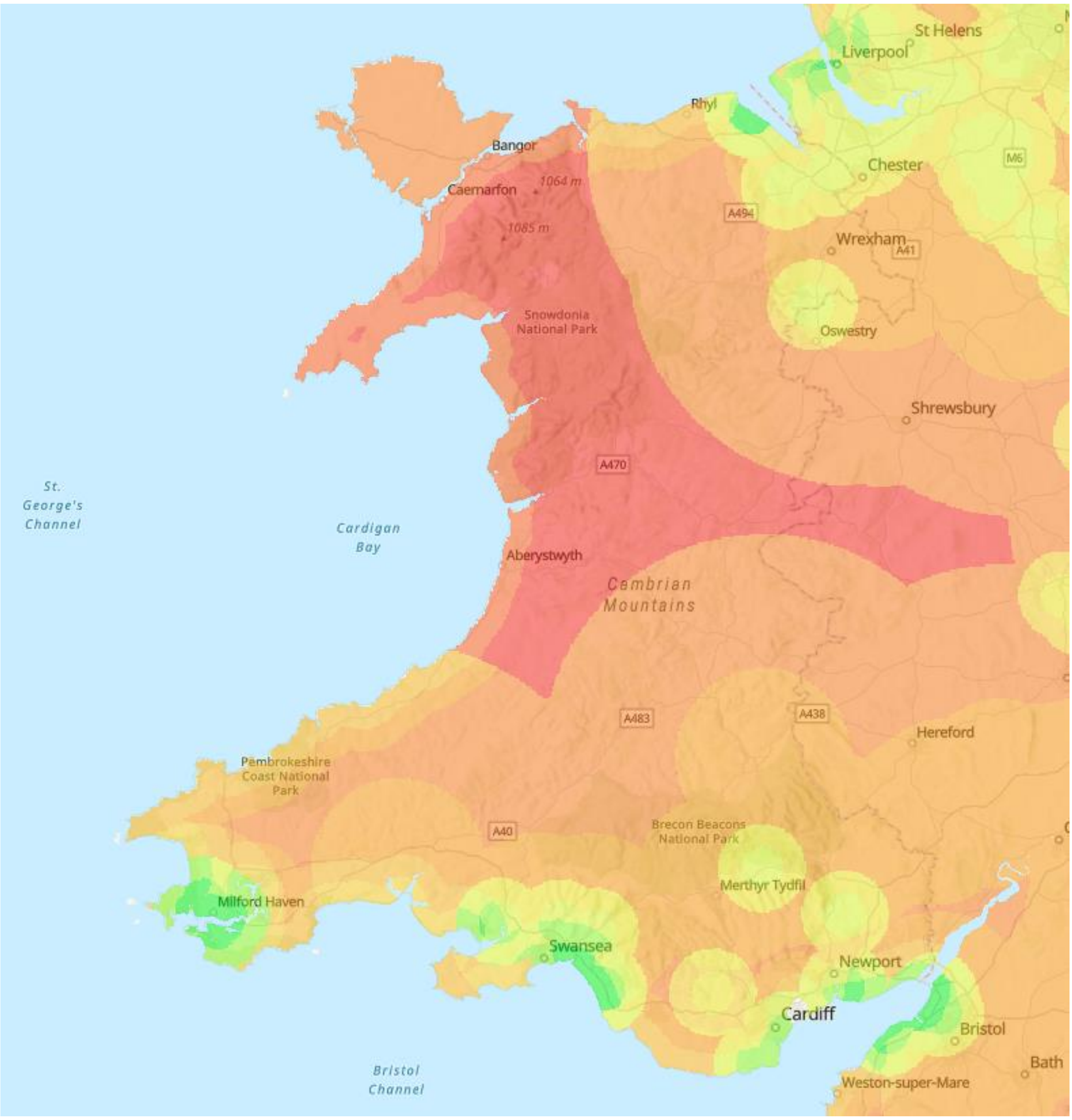
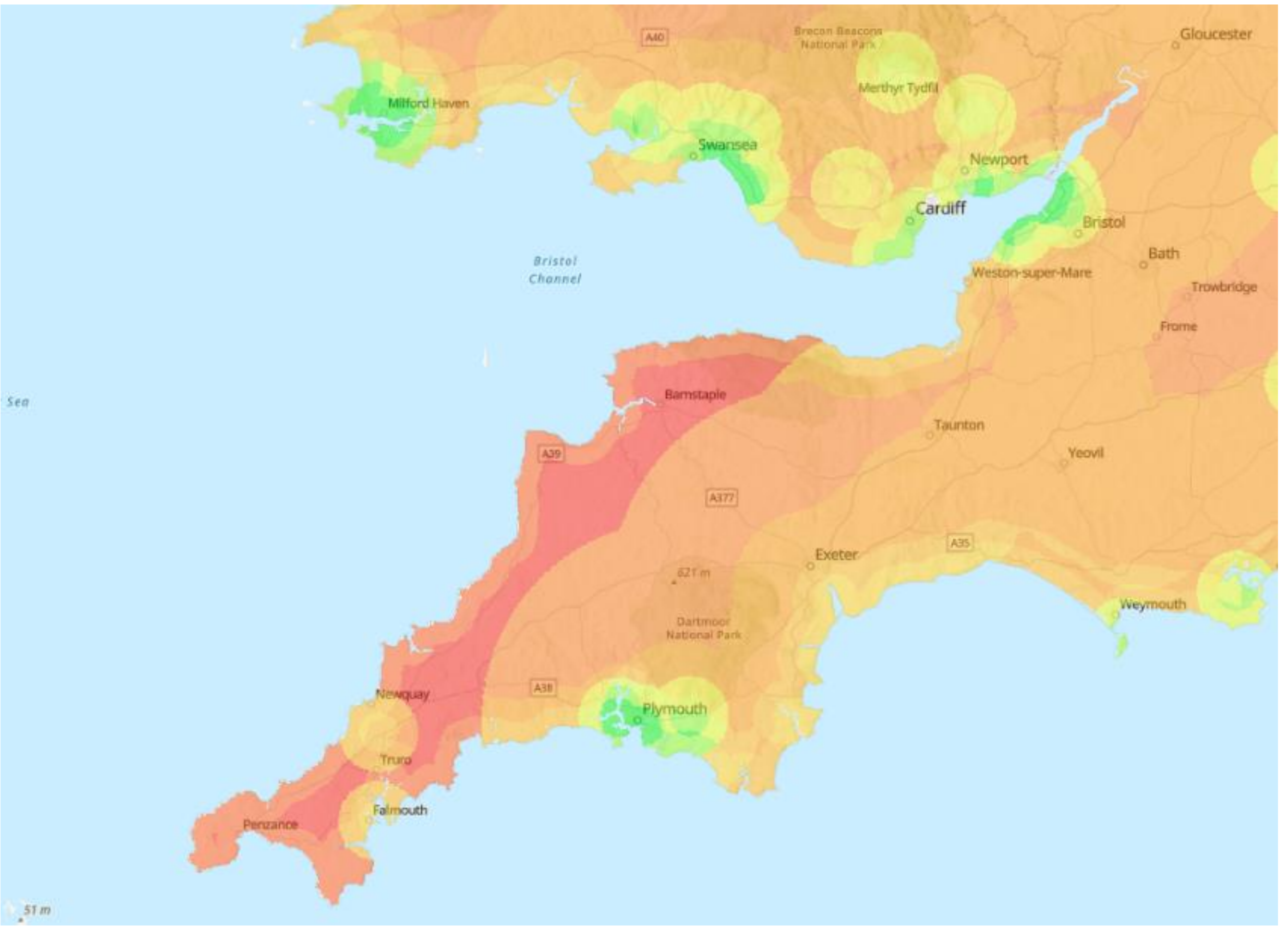


Figure 46 Potential Blue Hydrogen Production Locations – South West



13.4.HYDROGEN PRODUCTION IN SOUTH WALES

An initial perspective has been developed based upon consideration of blue hydrogen due to the lower cost of production, greater maturity of hydrogen production solutions at scale and also the existing availability of LNG and natural gas within the South Wales region.

The Milford Haven LNG terminals presently import up around 20% of the UK's gas demand through the South Hook LNG and Dragon LNG terminals. Milford Haven is presently capable of delivering up to 40% of the UK's gas demand at maximum send-out capacity and up to around 25% of the UK's energy system demand (i.e. for gas and electricity).

As the selected location for two out the UK's three LNG terminals, Milford Haven is well qualified to be a large source of hydrogen production via the continued importation of LNG for blue hydrogen production and the potential to transition existing infrastructure and operations to import green hydrogen (potentially in the form of ammonia) in the future.

The main reasons why Milford Haven was chosen for LNG importation was:

a) It is located in the south and west of the UK: The LNG mainly comes from the Middle East or USA. LNG carriers do not have to spend time travelling to and from the east coast or further up the Irish sea to inject gas into the UK gas network.

b) For the large LNG carriers, the Milford Haven port facilities are less tide dependent, unlike port locations such as Swansea, Barry, Cardiff, Newport, Bristol and Portbury, which all have locks and offer more restricted access.

c) Milford Haven is a large natural deep-water harbour which has formed from a flooded fjord and is well sheltered from the prevailing south westerlies. The only other location with similar conditions in the South West is Falmouth, which is the deepest natural harbour in Western Europe.

d) Where access to the jetties at Milford Haven is temporarily congested, it is easier to manage congestion than further into the Bristol Channel where there is less space available.

The existing infrastructure in Milford Haven could therefore also play a key strategic role in facilitating the production and/or importation of hydrogen generally to support the provision of security of energy supplies in the UK as the legacy gas supply from the North Sea decreases towards 2050. In the future, Milford Haven could play a role for hydrogen as per the current situation for the supply of natural gas from LNG, becoming a key location for strategic energy storage (as LNG) and a major source of gas to Great Britain.

There is potential for installation of multiple blue hydrogen production trains at Milford Haven. The potential blue hydrogen production from LNG in South Wales is summarised in Table 11. Potential Hydrogen Production Capacity from LNG in South Wales. This shows that potentially a maximum of 17,800 tpd of blue hydrogen could be produced based on the nominal capacity. Taking 80% as the average send out (in consideration of historical supply/demand for LNG), an equivalent blue hydrogen production capacity of 14,000 tpd would be possible. Taking a nominal hydrogen plant capacity 800 MW or about 500 tpd, 28 blue hydrogen production trains could be operated based upon the present-day LNG supply capacity.

Table 11. Potential Hydrogen Production Capacity from LNG in South Wales

LNG Terminal	Natural Gas Export Capacity	Equivalent Blue Hydrogen Production
Dragon LNG	5.6 Mtpa = 7.6 bcma = 21.0 MCMD	4,730 tpd = 9 blue hydrogen plants
South Hook LNG	15.6 Mtpa = 21.0 bcma = 58.1 MCMD	13,070 tpd = 26 blue hydrogen plants
Total	**21.2 Mtpa = 28.6 bcma = 79.1 MCMD**	**17,800 tpd = 35 blue hydrogen plants**

This analysis indicates Milford Haven could be a net exporter of blue hydrogen via a hydrogen NTS operating in a similar fashion to current natural gas NTS dynamics. A dedicated hydrogen transmission pipeline would need to be available to export hydrogen from South Wales to other regions with demand for hydrogen. This could be provided by converting the current NTS (Feeder 28) to hydrogen, and/or via a new dedicated hydrogen transmission pipeline linking to repurposed sections of the existing NTS.

In consideration of Great Britain’s gas network decarbonisation and industrial cluster plans, the hydrogen pipeline would ideally be required by 2030 such that hydrogen production in Milford Haven could be rapidly increased by phased capacity additions and not constrained to meeting local industrial demand.

Designing Milford Haven hydrogen production capacity for network peak demand in South Wales means that there will be practically no reliance on long term storage, with diurnal demand variations potentially being handled by line pack and flexible capacity bookings on the hydrogen NTS offtakes, as per current operation.

The local port infrastructure could also allow South Wales (particularly Milford Haven) to become a strategic UK location for energy commodities such as ammonia and liquefied hydrogen importation and storage facilities in the long term, on the basis that global markets would be established by 2050 in a similar fashion to current LNG trade.

It is acknowledged that there is also potential for the installation of additional green hydrogen generation capacity in South Wales from electrolysis using renewable energy, particularly from offshore wind power generation. Potential capacity for the future offshore floating wind power from the Celtic Sea is around 150-250 GW, expected to be achieved by 2035. This represents a potential green hydrogen generation from electrolysis equivalent to circa 1,000 tpd of hydrogen at 55% load factor.

Multiple sources will provide the required resilience to guarantee security of supply, in this case provided by multiple blue hydrogen trains plus additional green hydrogen generation capacity from electrolysis, and potentially from the import of ammonia in the long term.

According to the National Atmospheric Emissions Inventory (NAEI) database (Emissions from NAEI large point sources - NAEI, UK (beis.gov.uk)), over three quarters of the industrial emissions associated within Wales and the South West are produced in South Wales by three emitters at two geographical locations (i.e. Milford Haven and Port Talbot). The decarbonisation decisions which are taken by these three stakeholders are likely to have an extremely significant impact upon the decarbonisation solutions and infrastructure which is implemented within WWU's region in future (as well as when it is implemented).

1. Tata Steel Port Talbot
2. Pembroke Power Station
3. Pembroke Oil Refinery

Pembroke Power Station and Pembroke Oil Refinery are two of the largest emitters of CO_2 in Wales, with a ready supply of natural gas available from the conveniently located LNG terminals. Fuel switching from natural gas to hydrogen is therefore a potential pathway to decarbonise their site operations. Although the asset owners have still to make any firm decisions on the project solutions they intend to progress.

From the potential industrial hydrogen demand perspective, Milford Haven is therefore a prime site for the location of a blue hydrogen site for local consumption, along with the ability to inject hydrogen into the gas network. Export of captured CO_2 (including liquefaction and local storage) would be via ships to sequestration sites, taking advantage of the potential use of the existing maritime infrastructure for CO_2 ships loading.

Tata Steel have publicly declared they have chosen the hydrogen route for decarbonisation at its Ijmuiden steelworks in the Netherlands, which will involve the introduction of Direct Reduced Iron (DRI) and/or electric arc furnace technology. Emissions reduction with CCS retaining the existing coal feedstock is considered to be less likely due to the associated negative public perception.

Tata Steel have still to decide if they will follow a similar path to their site in the Netherlands at Port Talbot. If this is the case, then this could help establish Port Talbot as a further location to develop blue hydrogen production in South Wales given the deep-water harbour at the site plus its relative proximity to an NTS connection.

With multiple emitters and processes on site, there are several permutations that Tata Steel could choose to decarbonise the site over varying time durations. If Tata Steel does proceed with a DRI technology solution, then the level of production is more likely to be on a similar scale to an initial hydrogen project at Pembroke Power Station. Although the Tata Steel site at Port Talbot is the largest industrial emitter in South Wales, that does not necessarily equate to their becoming the largest hydrogen consumer after they have decarbonised their operations.

13.5. HYDROGEN PRODUCTION IN NORTH WALES

Blue hydrogen is also considered for hydrogen supply in North Wales given the availability of blue hydrogen from the HyNet project in the North West. It is assumed that capacity will be sufficient to supply North Wales, with adequate network resilience to ensure security of supply.

HyNet is expected to supply at least one major power station combusting 100% hydrogen as a fuel while also being and used to decarbonise heavy transport (trains, heavy goods vehicles, buses and ships) in the North West. Production will initially be from the blue hydrogen plant at Stanlow, then extending to further production sites across the region including potential for a hydrogen to be produced at a cogeneration hydrogen production facilities at Wylfa.

Blue hydrogen production capacity from the HyNet North West project is expected to grow in stages as shown in Table 12. Phase 1 targets 350 MW (about 200 tpd of hydrogen), potentially operational as soon as 2025. Expansion is planned to happen shortly thereafter, with Phase 2 increasing capacity by 700 MW by 2026. Phases 3 and 4 at 1,400 MW each will follow in 2028 and 2030. Total hydrogen production capacity is expected to reach 3.8 GW (~2350 tpd) equivalent to over 30 TWh per year by 2030 with ambitions for 15.6 GW (~9650 tpd) equivalent to 130 TWh per year by 2050.

Table 12. HyNet Build-out Phases

Hydrogen Production	Hydrogen Network	Hydrogen Storage	Hydrogen Consumers
Plant 1 (350 MW) in operation by 2025 at Stanlow	Phase 1 pipelines from plant to Essar and 2 or 3 other local consumers	None	Stanlow Manufacturing Complex, 2 other industrial consumers, Hydrogen Village and local blending
Plant 2 (700 MW) in operation by 2026 at Stanlow	Phase 2 network from Stanlow to storage, St Helens Warrington and Trafford commissioned by 2026/7	First salt caverns at Keuper in operation by 2026/7	Connections to 10-15 large industrial and flexible power generation consumers close to Phase 2 network in operation by 2026/7. Also connection into Cadent Local Transmission System for blending at scale
Plants 3 and 4 in operation by 2028 and 2030 respectively bringing total capacity to 3.8 GW	Phase 3 network commissioned by 2030	1.3 TWh of working storage capacity in operation	30 TWh/y of demand connected across the whole system to include Transport users as well as further blending into Cadent and Wales and West Utilities networks. Over 30 industrials and flexible power generators receiving hydrogen from HyNet

The HyNet hydrogen network including hydrogen storage is forecast to expand in accordance with the build-out phases as described in Table 12. Salt caverns will start to be developed in 2026 to reach 1.3 TWh storage capacity by 2030. In line with the hydrogen network plan, early hydrogen supply (Phase 1 and 2) will be developed around industrial demand in the cluster, with gas distribution (for North West and North Wales) being connected by 2030 to reach distributed industry demand and for transport and domestic use of up to 24 TWh per annum (above baseload industrial demand in clusters).

Existing offshore wind farms are connected to the electricity transmission system. In North Wales, annual production is approximately 29 TWh at 55% load factor equivalent to 6 GW. If the produced energy cannot be exported in the form of electricity, it may be necessary to consider conversion to green hydrogen. The potential green hydrogen capacity is about 1,500 tpd (based on present day performance and installed capacity and nominal 50 kWh/kg Hydrogen).

13.6. HYDROGEN PRODUCTION IN THE NORTHERN SOUTH WEST

The South West is expected to eventually be supplied via the hydrogen NTS (see Figure 35), with complementary localised blue hydrogen production dependent on natural gas supply being retained and the availability of CO_2 transport infrastructure, likely to be by ship and green hydrogen from local solar and wind power generation.

Blue hydrogen production could be located in the Avonmouth area to take advantage of the proximity of the NTS for natural gas supply and a port to allow for the transport away of CO_2.

There is also potential for the installation of green hydrogen generation capacity at a smaller scale in the South West from electrolysis using renewable energy. Also, potential exists for hydrogen to be produced at cogeneration hydrogen production facilities at Hinkley Point and Oldbury sites.

13.7. HYDROGEN PRODUCTION IN THE SOUTHERN SOUTH WEST

The present single largest demand for natural gas in the South West is EPUKI's Langage Power Station. Unlike Pembroke Power Station in South Wales, the absence of other favourable factors mean it is considered less likely that there will be early location of hydrogen production in the region. If fuel switching using hydrogen is considered at Langage Power Station, supply of hydrogen which is produced outside of the region is initially anticipated to be the most likely solution. The main hydrogen supply for the gas distribution network is expected to come from multiple sources via a future hydrogen NTS pipeline as per current supply of natural gas or potentially via a new pipeline supplying hydrogen produced in South Wales.

There is potential to use renewables to produce hydrogen, as currently undergoing demonstration by the Dorset Green H_2 project using renewable energy generated by solar and landfill gases. This will potentially be focused on meeting hydrogen demand for transport.

14. NETWORK CAPACITY FOR HYDROGEN

14.1. APPROACH TO NETWORK CAPACITY EVALUATION

14.1.1. SIMPLIFIED HYDRAULIC MODELLING

Current best practice for the analysis of gas pipeline network configurations under specific operational conditions of supply and demand uses numerical models derived from one-dimensional momentum and energy equations, derived from the laws of conservation of mass, momentum and energy plus equations of state to model gas compressibility. Hydraulic gas network models include representation of infrastructure and equipment such as pipelines, valves/regulators, storage and compressor infrastructure, entry and exit points, allowing different scenarios for (peak) gas demands and gas supplies to be evaluated. Gas compressibility and physical properties are simulated against gas composition and operating pressure and temperature.

Hydraulic modelling was excluded from the scope of the present study, which used energy systems modelling to generate the network conversion insights. To approach the evaluation of the gas network capacity, representative operating conditions have been evaluated in a simplified single-pipe hydraulic model. Representative pipe size and section lengths have been identified and selected for the analysis from network data for the WWU supply area. Representative operating pressures for each pressure tier have been used, and an indicative pressure loss from pipeline design practice has been considered.

The analysis presented in this section is intended to provide considerations related to the implications of network conversion to transport and distribute hydrogen, in consideration of pressure losses and gas velocity constraints and the impact on potential network reinforcement. The outcomes of this section have not been incorporated in the conceptual plans, and these remain at a high level showing the conversion pathway rather than specific and detailed reinforcement plans for sections of the network. Rigorous hydraulic modelling in subsequent phases is recommended and required for the specific evaluation of network capacity.

14.1.2. MODELLING CASES

The evaluation quantified natural gas and hydrogen flows, pressure losses and gas velocities for the following cases:

1. **Case 1: Benchmark Gas Capacity**. Determination of capacity (i.e. maximum gas flow) of pipe of the given size to transport natural gas at the assumed operating pressure and pressure loss design criteria.
2. **Case 2: Same Energy Transported.** Simulation of the required flow of hydrogen to transport the same amount of energy than for the natural gas flow determined in Case 1. Volumetric flows of hydrogen are 3.3 times the volumes of natural gas given the ratio of volumetric calorific values. Pressure loss and velocities are higher than in Case 1.
3. **Case 3: Pressure Loss Constraint.** Evaluation of the maximum hydrogen flow determined by the assumed pressure loss constraint. The proportion of energy transported in this case is compared to that transported by natural gas from Case 1.
4. **Case 4: Gas Velocity Constraint.** Evaluation of the maximum hydrogen flow determined by a maximum gas velocity constraint of 20 m/s as per current pipeline design standards. The proportion of energy transported in this case is compared to that transported by natural gas from Case 1.

14.1.3. PIPELINE CAPACITY FOR CONVERSION TO HYDROGEN

The calorific value of natural gas (based on its Higher Heating Value, HHV) is around 11 kWh/Sm^3, which is about 3.3 times the calorific value of hydrogen at 3.4 kWh/Sm^3. Therefore, at the same conditions of pressure and temperature, the volumetric flow of hydrogen required to keep the same energy supply is about three times the volumetric flow of natural gas.

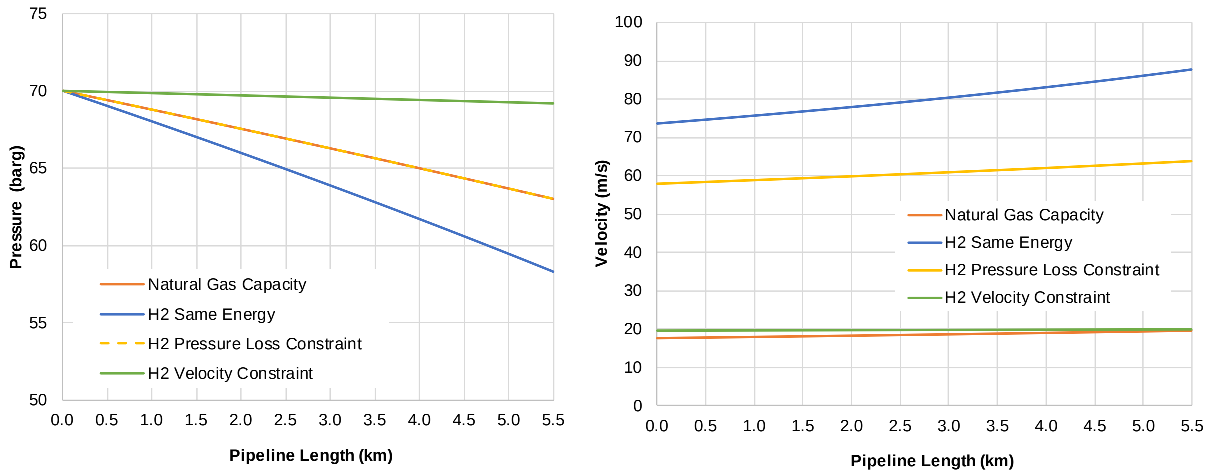
This suggest that network reinforcement via replacement of pipelines with larger size or installation of pipelines in parallel would be required to provide the capacity to transport increased volumetric flows of hydrogen.

The network capacity is not only defined by gas velocity constraints, set to mitigate the risk of erosion (considering potential solid particles in the pipelines from corrosion and deposition products), but by the ability to supply extreme sections at the required pressure. Evaluation of hydraulic capacity from the pressure loss perspective must consider the fact that pressure loss is a function of fluid momentum determined as the product of density (ρ) and gas velocity squared (v^2). This is shown by the simple Darcy-Weisbach equation below.

$$\frac{\Delta P}{L} = \frac{\lambda \rho v^2}{2D}$$

From this perspective, hydrogen transport benefits from a reduced density (about 1 tenth of the density of natural gas at the same conditions). The net result is that for a given pressure loss over a certain pipeline length, the volumetric flow of hydrogen is still lower than natural gas but not too dissimilar. For example, Figure 47 shows that for an operating pressure of 70 barg in a 36” pipeline, the energy transported as hydrogen (31.2 GW or 222 MCMD of hydrogen) is about 78% of that transported as natural gas (39.7 GW or 87 MCMD of natural gas) for the same pressure loss of 7 bar (over 5.5 km). It is noted that the pipeline capacity for natural gas does not necessarily represent current peak flows and a margin is expected. If current peak flows are a nominal 80% of pipeline capacity, then potentially the same energy could be transported in the future as hydrogen.

Figure 47 Pressure and Velocity Profile for 36" Pipeline at 70 barg



On the other hand, velocity increases significantly from around 20 m/s for the case of natural gas to around 60 m/s for the case of hydrogen, as shown in Figure 47 .

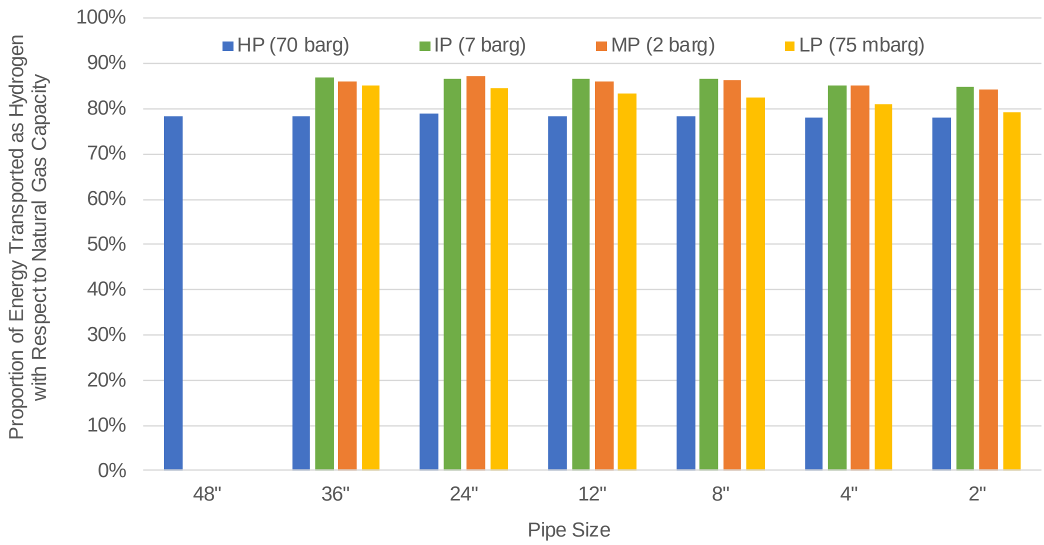
For the example of Figure 47 , the pressure loss increases to 12 bar if an increased hydrogen flow is considered to match the energy flow from natural gas (39.7 GW or 284 MCMD of hydrogen). The gas velocity increases considerably to a maximum of almost 90 m/s. If a velocity constraint of 20 m/s was used, then the energy transported as hydrogen is only 27% of the maximum transported as gas.

14.2.MODELLING RESULTS

Based upon the above, the set of results showing the potential envelope of hydrogen flows, pressure loss and velocity for the range of pressure tiers and pipe sizes is given in Table 13.

The proportion of energy transported as hydrogen with respect to natural gas capacity is around 80-90% as shown in Figure 48, for hydrogen flows determined based on the pressure loss basis.

Figure 48 Proportion of Energy Transported as Hydrogen with Respect to Natural Gas Capacity based on Pressure Loss Constraint (Case 3)



Considering a maximum gas velocity constraint of 20 m/s results in hydrogen flows generally reduced as shown in Figure 49Figure 49 Proportion . A trend could be observed, with flows approaching (and potentially exceeding) 100% of the energy flows from natural gas as pipe sizes are reduced. If the gas velocity constraint can be increased, it would allow a proportional increase in hydrogen flows.

Figure 49 Proportion of Energy Transported as Hydrogen with Respect to Natural Gas Capacity based on 20 m/s Velocity Constraint (Case 4)

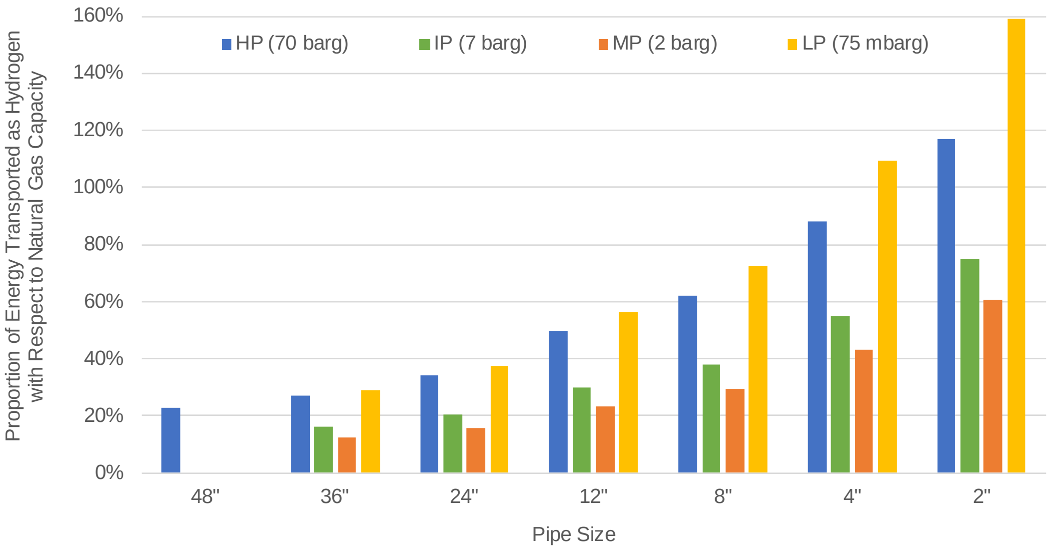


Table 13. Hydraulic Analysis Results for Representative Gas Network Pressure Tiers

Pipe Size	Case	HP				IP				MP				LP			
		Operating Pressure 70 barg				Operating Pressure 7 barg				Operating Pressure 2 barg				Operating Pressure 75 mbarg			
		Pressure Loss Basis 125 bar/100m				Pressure Loss Basis 60 mbar/100m				Pressure Loss Basis 40 mbar/100m				Pressure Loss Basis 2.5 mbar/100m			
		Pipe Length Basis 5500 m				Pipe Length Basis 3500 m				Pipe Length Basis 2500 m				Pipe Length Basis 2000 m			
		ΔP	Flow	Energy	Velocity	ΔP	Flow	Energy	Velocity	ΔP	Flow	Energy	Velocity	ΔP	Flow	Energy	Velocity
		bar	MCMD	%	m/s	bar	MCMD	%	m/s	bar	MCMD	%	m/s	bar	MCMD	%	m/s
48"	Benchmark Gas Capacity	7	185	100%	21-23												
	Same Energy Transported	12	606	100%	88-105												
	Pressure Loss Constraint	7	475	78%	69-76												
	Gas Velocity Constraint	1	137	23%	20-20												
36"	Benchmark Gas Capacity	7	87	100%	18-19	2.0	16.8	100%	37-49	1.0	8.3	100%	49-73	0.050	1.3	100%	21-22
	Same Energy Transported	12	284	100%	74-88	2.8	54.9	100%	124-188	1.4	27.1	100%	162-304	0.068	4.2	100%	69-73
	Pressure Loss Constraint	7	222	78%	58-64	2.0	47.7	87%	107-142	1.0	23.3	86%	139-205	0.050	3.5	85%	58-61
	Gas Velocity Constraint	1	76	27%	20-20	0.1	8.8	16%	20-20	0.0	3.3	12%	20-20	0.007	1.2	29%	20-20
24"	Benchmark Gas Capacity	7	29.5	100%	14-15	2.0	5.7	100%	29-38	1.0	2.8	100%	38-57	0.050	0.43	100%	16-17
	Same Energy Transported	12	96.4	100%	58-69	0.1	18.6	100%	96-147	1.5	9.2	100%	126-237	0.070	1.40	100%	53-57
	Pressure Loss Constraint	7	76.0	79%	45-50	2.0	16.2	87%	84-111	1.0	8.0	87%	110-164	0.050	1.18	84%	45-47
	Gas Velocity Constraint	3	32.9	34%	20-20	0.2	3.8	20%	20-20	0.1	1.4	16%	20-20	0.024	0.52	37%	20-20
12"	Benchmark Gas Capacity	7	5.3	100%	9-10	2.0	1.0	100%	19-26	1.0	0.5	100%	26-38	0.050	0.07	100%	11-11

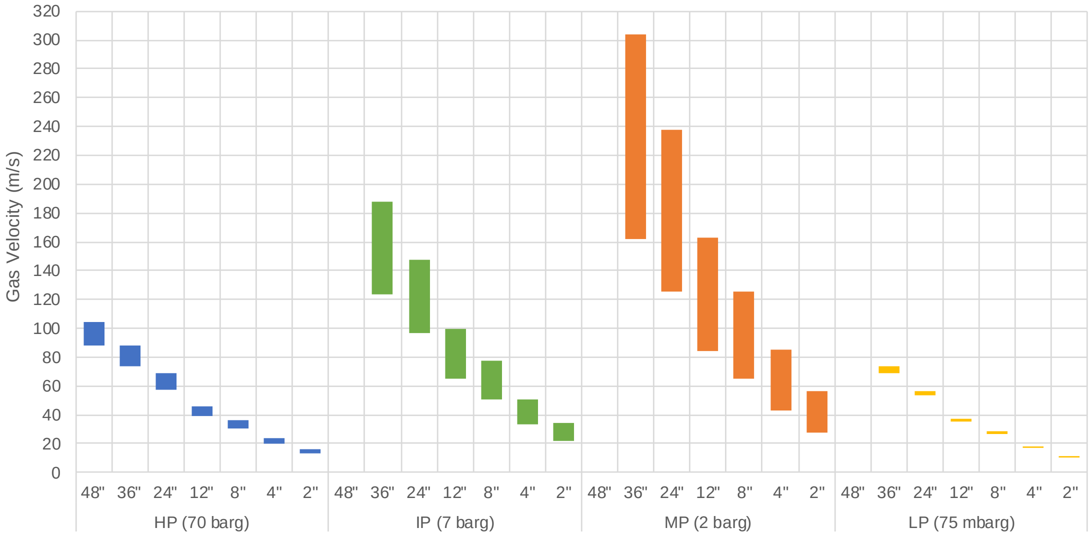
	Same Energy Transported	12	17.3	100%	39-46	0.1	3.3	100%	65-99	1.5	1.6	100%	84-163	0.070	0.24	100%	35-37
	Pressure Loss Constraint	7	13.5	78%	30-34	2.0	2.9	87%	56-75	1.0	1.4	86%	73-108	0.050	0.20	83%	29-30
	Gas Velocity Constraint	3	8.6	50%	19-20	0.2	1.0	30%	20-20	0.1	0.4	23%	20-20	0.024	0.14	56%	20-20
8"	Benchmark Gas Capacity	7	1.8	100%	7-8	2.0	0.4	100%	15-20	1.0	0.2	100%	20-29	0.050	0.03	100%	8-9
	Same Energy Transported	12	6.0	100%	30-36	2.8	1.1	100%	50-78	1.4	0.6	100%	65-125	0.071	0.08	100%	27-29
	Pressure Loss Constraint	7	4.7	78%	24-26	2.0	1.0	87%	44-58	1.0	0.5	86%	56-84	0.050	0.07	83%	22-23
	Gas Velocity Constraint	4	3.7	62%	19-20	0.4	0.4	38%	19-20	0.1	0.2	30%	19-20	0.039	0.06	72%	19-20
4"	Benchmark Gas Capacity	7	0.31	100%	5	2.0	0.06	100%	10-13	1.0	0.03	100%	13-19	0.050	0.004	100%	5
	Same Energy Transported	12	1.00	100%	20-24	2.8	0.19	100%	33-51	1.5	0.09	100%	43-85	0.073	0.013	100%	17-18
	Pressure Loss Constraint	7	0.78	78%	16-17	2.0	0.16	85%	28-37	1.0	0.08	85%	36-54	0.050	0.014	81%	14-14
	Gas Velocity Constraint	9	0.88	88%	18-20	3.8	0.10	55%	18-20	0.3	0.04	43%	18-20	0.086	0.015	109%	18-20
2"	Benchmark Gas Capacity	7	0.05	100%	3	2.0	0.010	100%	6-9	1.0	0.005	100%	8-12	0.050	0.001	100%	3
	Same Energy Transported	12	0.17	100%	13-16	2.9	0.033	100%	22-34	1.5	0.016	100%	28-56	0.076	0.002	100%	11-11
	Pressure Loss Constraint	7	0.14	78%	10-11	2.0	0.028	85%	18-24	1.0	0.013	84%	23-35	0.050	0.002	79%	8-9
	Gas Velocity Constraint	17	0.20	117%	15-20	1.5	0.025	75%	16-20	0.5	0.010	61%	17-20	0.178	0.003	159%	17-20

The range of gas velocities (over the assumed pipe section lengths) for the case of natural gas pipe capacity is shown in Figure 50. As noted before, maximum natural gas flows for a given pipe size and operating pressure were determined for the pressure loss basis. As shown in Figure 50, the case exists for some of the maximum natural gas flows being dictated by gas velocity constraint (e.g. 20 m/s) rather than by pressure loss.

Figure 50 Range of Gas Velocity for Assumed Length Pipeline Section – Benchmark Gas Capacity (Case 1)

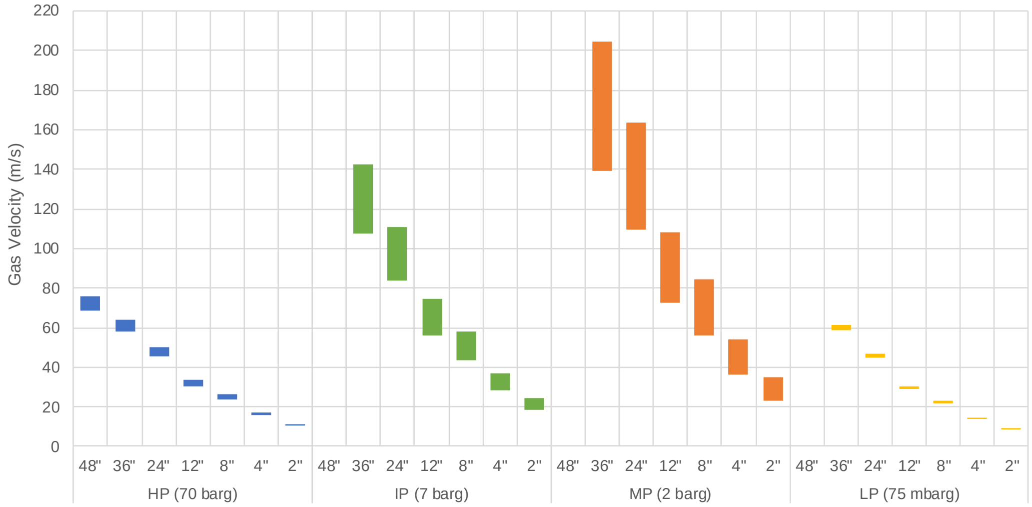
Considering hydrogen flows that would transport the same amount of energy (i.e. 3.3 times the volumetric flows of natural gas) result in the range of velocities as shown in Figure 51. As noted before, it is likely that energy flows as natural gas are already constrained. The graph in Figure 51 shows a considerable increase with respect to the base natural gas flows, for example for the HP network natural gas velocities at around 20 m/s or below, theoretically increased up to around 100 m/s.

Figure 51 Range of Gas Velocity for Assumed Length Pipeline Section – Same Energy Transported (Case 2)



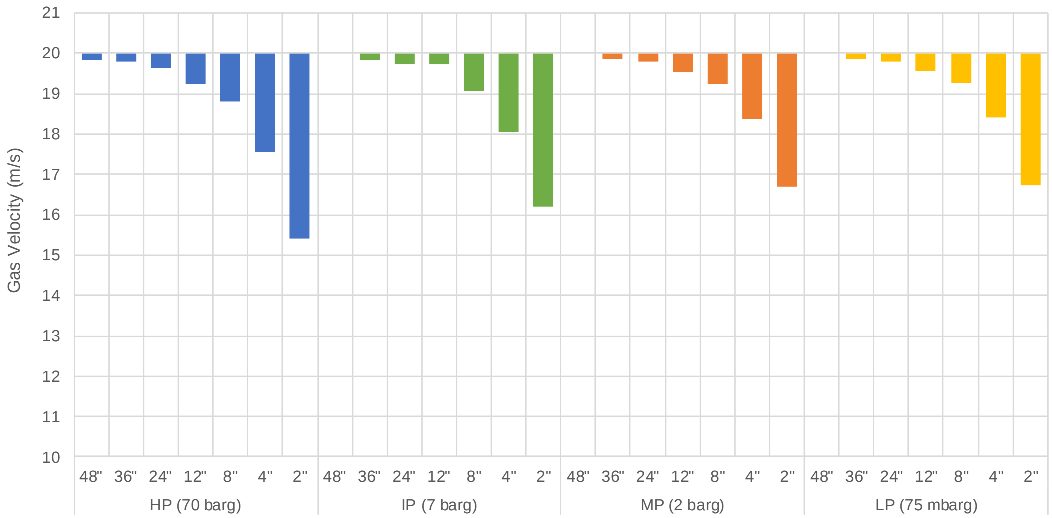
The range of gas velocities for the case of hydrogen determined by the same pressure loss basis applied to natural gas is shown in Figure 52. Similar considerations to those highlighted for Figure 51 apply, with relatively lower velocities in line with hydrogen flows.

Figure 52 Range of Gas Velocity for Assumed Length Pipeline Section – Pressure Loss Constraint (Case 3)



Considering the hydrogen flows determined by a gas velocity of 20 m/s result in the range of velocities shown in Figure 53 for the assumed pipe section lengths.

Figure 53 Range of Gas Velocity for Assumed Length Pipeline Section – Gas Velocity Constraint (Case 4)



14.3.APPROACH TO NETWORK REINFORCEMENT

Potential hydrogen flows that could be transported to meet pressure loss conditions are expected to result in energy flows that are not too dissimilar to those transported by natural gas, particularly in consideration of any existing margins between pipeline capacity and peak flows (and less of a concern for normal operating flows from typical demand range).

Detailed assessment of gas velocities on a case-by-case scenario as determined by rigorous hydraulic modelling of the gas network for the transport of hydrogen will indicate the potential requirement for network reinforcement where gas velocities are excessive, based on the following alternatives:

1. Replacement of existing pipelines with large bore systems, specially where integrity and end of life considerations apply (i.e. pipe sections already being part of a gas mains replacement programme);
2. Installation of pipelines in parallel to existing infrastructure to provide additional capacity.

Gas velocity constraints have been set to mitigate the risk of erosion considering potential solid particles in the pipelines, derived from corrosion and deposition products. An increase in maximum operating velocity allowance would allow increased volumes of hydrogen to be transported before investment in network reinforcement is required. This could be justified against mitigation of the erosion risk, e.g. injection of filtered gas, use of polyethylene piping and risk-based pipeline integrity management (e.g. more frequent integrity condition assessments).

15. HYDROGEN STORAGE CAPACITY

15.1. ENERGY STORAGE TO MANAGE DEMAND VARIATIONS

To maintain network resilience and meet security of supply obligations, energy storage is required to ensure sufficient supply during periods of peak demand. Daily variations in the energy supplied as gas are much greater than the variation in electricity demand, mainly due to heat generation loads met by gas supplies. Between 5 am and 8 am on a winter day, UK gas demand increases by over 100 GW, which is much higher than the total electricity system demand.

For the supply of electricity, to maintain electricity system operability it is necessary to continually and instantaneously match supply and demand across the system. Any shortages in electricity supply with respect to demand, particularly in consideration of the intermittency in renewable power generation are currently managed by dispatchable power generation – predominantly in the form of gas-fired CCGT plants. Demand side management has been proposed to instantaneously match the available renewable energy in a future system with reduced reliance on fossil fuels for power generation. The degree of instantaneous and seasonal variation in power demand could be expected to increase in the future, as some of the energy demand for heat and transport is supplied by electricity. Where electricity system limits on supply and demand are reached, energy storage will therefore be required.

To unlock value from the UK's energy systems as a whole, it is important to understand both the capability of both the gas and electricity networks, and also the likely impact of transferring each different type of energy demand, particularly for heat. If the most feasible way of providing inter-seasonal energy storage in future remains in the form of fuel (as at present), then the optimal solution for heat decarbonisation may be via conversion of the present gas grid to hydrogen use. For in-day variations, dispatchable power generation using hydrogen-fired CCGT plants may replicate current practice, ensuring system resilience and security of supply to buffer renewables intermittency.

For the supply of gas, diurnal variability in gas demand is managed by firm and flexible offtake capacity bookings and line pack storage. For the seasonal variations, these are currently managed by underground gas storage, LNG and gas supplies via the interconnectors with European gas infrastructure.

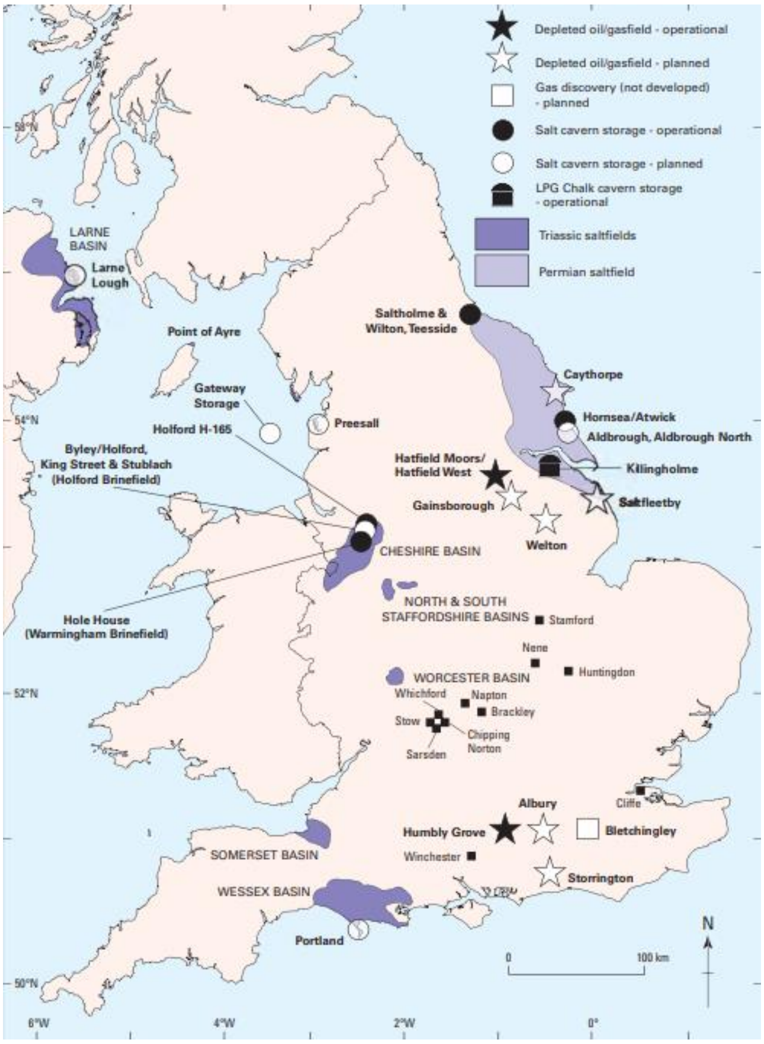
15.2. STORAGE TO MANAGE SEASONAL HYDROGEN DEMAND VARIATION

There is a far larger seasonal variation in gas demand compared with electricity demand. This is largely attributed to space heating requirements, with the average winter gas demand being 4 to 6 times that of the summer demand. Meeting this level of variation in demand requires other forms of storage beyond line pack, and is generally provided from underground gas storage, imports via interconnectors or in the form of LNG under present natural gas system operations.

The UK currently has eight active underground storage sites with a combined storage capacity of 1.31 BCM and a maximum combined output rate of 106 MCMD. Underground gas storage can provide significant storage volumes: for example, the Stublach gas storage project has a declared capacity of 400 MCM which could provide storage for about 33,800 tonnes of hydrogen. The Holford gas storage project can store about 237 MCM, equivalent to about 20,000 tonnes of hydrogen. The HySecure project for storage of hydrogen in a salt carvern is considering a working gas volume of at least 11,00 tonnes of hydrogen for Phase 1 of the project.

Potentially suitable areas for underground storage in Great Britain are shown in Figure 54. For a salt caverns to be utilised as a gas storage location, the deposit of salt must be relatively pure and greater than 100 m thick. The Somerset Basin has not been proposed as a gas storage location to date. However, there are existing or potential underground storage options in both the Cheshire and Wessex Basins which are located on the border of the WWU supply area.

Figure 54 Distribution of the Main Halite Bearing Basins in Britain and the Location of Operational / Proposed Underground Gas Storage Sites



Source: https://www.hse.gov.uk/research/rrpdf/rr605.pdf

The three LNG storage facilities at Isle of Grain, South Hook and Dragon LNG have a combined storage capacity equivalent to 1.2 BCM of natural gas, and a maximum combined gas send out rate of 139 MCM of gas per day.

Considering the whole of the Great Britain gas demand, it is anticipated that hydrogen storage capacity will need to be expanded at the level of several hundred GWh per year from 2025. As per network conversion, it is expected that during the transition period, hydrogen storage will be developed whilst maintaining the required natural gas storage. Therefore, increase in hydrogen storage capacity cannot be solely at the expense of converting natural gas storage and new storage facilities must also be built.

Options for long term hydrogen storage include:

- **Underground Storage**. Storage of pressurised hydrogen at 100-150 barg in aquifers, salt caverns, or empty natural gas fields. Approximately 100 salt caverns are either already being used for natural gas storage or are under consideration for gas storage. The HySecure project will demonstrate the deployment of grid-scale storage of hydrogen in a salt cavern in the North West of England.
    - The levelised costs for underground storage are about 20% the costs of hydrogen storage in pressurised or liquefied form. Land use issues can be significant, including the space requirement for above-ground infrastructure (related to hazardous areas) and below ground (larger or more cavities needed due to hydrogen's lower energy density).
    - The option to utilise underground storage in the Wales and the South West supply area is limited due to the underlying geology.
- **Pressurised Hydrogen.** The scope for storage of hydrogen in pressurised form is limited compared to natural gas, given the significant difference in terms of energy density. Large infrastructure is required to provided the required volumes at moderate pressures, for example to store 1 MCM at 70 barg would require 24 km of 36" pipe.
    - Composite pressure vessels can withstand pressures up to 1,000 barg, but the volume of hydrogen per vessel is limited, although banks of vessels can be deployed. This form of storage will be tested by the H100 project.
    - High pressure storage of hydrogen in steel vessels (or piping) for large scale capacities is perceived to be limited due to the large capital costs, although these may be adequate for road transport and relatively small-scale storage in hydrogen refuelling stations
- **Liquefied Hydrogen.** Liquefying hydrogen reduces the volume to about 8% of the volume required to store compressed gas at 70 barg. However a significant energy input is involved in the liquefaction process, resulting in a shrinkage of hydrogen to about 60% of the feed to the liquefaction plant, the other 40% of the gaseous hydrogen feed assumed to be used to provide the equivalent energy required.
    - Potential loses due to boil off gas need to be considered, which makes liquid hydrogen more appropriate for short term storage (e.g. peak shaving), in a similar fashion to LNG for the supply of natural gas. Only vaporisation is

required with no purification as the hydrogen is highly pure which makes reconversion relatively straightfoward and fast-responsive to demand.

- **Liquid Organic Hydrogen Carriers (LOHCs)**. Conventional petroleum derived products such as Toluene and Dibenzyltoluene (DBT, a heat transfer oil) store hydrogen in chemical form by hydrogenating the unsaturated organic molecules. For a given volume of hydrogen, storage volume can reduce to about 14% of the storage volume required for pressurised hydrogen at 70 barg. Dehydrogenation to release the hydrogen requires energy in the form of heat, which may use 30-40% of the energy being delivered as hydrogen. The system is favoured by the availability of heat and heat integration at the conversion and reconversion stages. Some form of heat storage may make the scheme feasible for peak shaving schemes.
    - Purification of hydrogen is required, which may lead to a tail gas being generated and to be utilised (as fuel gas) to minimise hydrogen loses. Generally, the hydrogenated liquid is stable and can be stored in conventional atmospheric tanks used for oil products. This form is therefore appropriate for seasonal storage and for distribution of hydrogen by road, rail or ship.
- **Ammonia.** Storage of hydrogen as blue or green ammonia (produced from blue or green hydrogen) allows the storage volume to be reduced to about 6% of the volume required to store pressurised hydrogen at 70 barg. Significant energy is required in the synthesis and subsequent cracking of ammonia. Nitrogen is also required as feedstock, to be supplied from an air separation plant. Such project schemes are most likely to be considered feasible where ammonia is the final product (ammonia can be used directly as fuel e.g. for shipping, supplemented by other fuels, ideally hydrogen).
    - Following cracking, separation of the nitrogen and hydrogen and purification of the later is required, which leads to a tail gas being generated and local utilisation preferred to avoid venting and loses of hydrogen. The infrastructure to store and transport ammonia as liquid is well established, and LPG infrastructure can also be used. Ammonia is more appropriate for long term storage and particularly for intercontinental shipping. The business model for ammonia as a future hydrogen carrier can potentially be developed based upon the current brown ammonia market (produced from natural gas with no CCS) taking account of any environmental incentives or cost of emissions in the future.

15.3. STORAGE TO MANAGE INSTANTANEOUS (DAILY) HYDROGEN DEMAND VARIATION

Capacity data for South Wales derived from network analysis as reported by WWU and shown in Table 14 indicates that to ensure security of supply to meet instantaneous demand, a margin is needed for storage being about 2.4 to 2.5 times the hourly peak flows (storage being 3.7 times the peak flow for the Gilwern network when supply to the Severn Power CCGT Power Station is included). The storage requirements for gas fired power plants (including potential future peaking plants) connected to the distribution network must be considered individually and, on a case-by-case basis.

Table 14. Storage to Demand Ratios

Offtake	Storage Needed (MCM/h)	Storage Needed (MCM)	Storage / Demand Ratio	Line Pack Available (MCM)	Flexible Capacity Bookings Available (MCM/h)
Severn Power Excluded (2021)					
Dowlais	0.484	1.212	2.50	1.253	-
Dyffryn	0.193	0.462	2.39	0.255	0.300
Gilwern	0.183	0.437	2.39	0.485	0.766
Severn Power Included (2020)					
Dowlais	0.483	1.195	2.47	1.290	-
Dyffryn	0.192	0.454	2.36	0.257	0.300
Gilwern	0.332	1.221	3.68	0.598	0.766

The storage required to meet hourly peak demand is currently provided by line packing (about 50-100% of the storage capacity required). Currently, the difference between the required daily storage capacity for an offtake zone and the line pack capacity is provided by flexible NTS offtake capacity bookings.

The hydrogen volume required to store the same amount of energy as natural gas is about 3 times the volume of natural gas. Following network conversion to hydrogen, the energy stored as hydrogen line packing will be about a third of current energy stored as natural gas line packing at the same pressure. Maximum operating pressures may be increased to allow more hydrogen to be packed within the pipelines volume, but the scope is limited in consideration of safety implications.

Due to the reduced energy stored as hydrogen in the pipelines volume, the gas network will have an increased reliance on flexible hydrogen NTS capacity bookings to supply peak energy demand. Gas network operators are currently incentivised to keep offtake capacity bookings under control, so as demand variation becomes more dependent on flexible NTS offtake capacity bookings, demand forecasting will become more critical for cost controls. It will be expected that price control schemes are developed in line with the future scenarios and requirements.

External hydrogen storage in the form of compressed hydrogen or other forms could be provided in addition to line pack and flexible NTS offtake bookings, with the condition that hydrogen is made available to meet instantaneous (hourly) demand. This could take the form of:

- Pressurised hydrogen stored in high pressure vessels, although the capacity is relatively limited for conventional pressure vessels, and a significant number of storage sites connected to the network would be required. High pressure composite vessels operating at pressures above 300 barg could be employed but the capital cost may limit the scope.
- Pressurised hydrogen stored in large bore (36”-48”) pipeline arrangements. This is a simple option, but it requires significant land to lay banks of pipes and this may be a constraint.
- Peak shaving facilities where hydrogen is liquified and regasified may also be considered to provide instantaneous capacity. This has been proven for LNG peak shaving facilities providing Operating Margin (OM) services. Liquefaction of hydrogen involves a significant energy penalty, and economics and overall energy conversion and supply efficiency would need to be assessed against security of supply requirements.
- Peak shaving facilities with hydrogen converted to liquid carriers such as ammonia or liquid organic hydrogen carriers (LOHC) and reconverted to release hydrogen during periods of high demand. Reconversion may not be as reactive as hydrogen stored in gaseous or liquified form. An energy efficiency penalty is associated to conversion and reconversion processes, and plants may operate inefficiently in non-continuous way.

Given the limited scope to provide hydrogen storage, particularly to support security of supply against diurnal demand variations, the potential for gas supply capacity set at the peak rate appears to provide a feasible way to approach security of supply. This essentially means a reliance on supply from a hydrogen transmission pipeline.

The ability to replenish the network during periods of demand near peak flows through the hydrogen NTS offtakes would need to be evaluated by means of hydraulic modelling, which would identify potential bottlenecks in the system to ensure network extremities do not reach a critical low pressure during this scenario.

Sizing the hydrogen NTS pipelines will not only consider the capacity required to transport the required volumetric flows of hydrogen in consideration of pressure loses and velocities, but also to consider the potential for line packing storage that would provide network resilience to cope with in-day demand variations.

It is realistic to assume that some areas will see a net reduction in energy supplied as gas (e.g. as a result of heat generation supplied by heat pumps or district heating) and therefore, the line pack capacity may potentially be adequate. However, in other zones the net energy demand may increase with respect to current levels as energy demand from transport would need to be supplied as hydrogen, adding more strain to the gas networks.

15.4.TRANSITIONAL AND END-STATE HYDROGEN STORAGE IN NETWORKS

The considerations described in the previous sections represent the expected end-state network configuration following conversion to hydrogen. The approach to provide hydrogen storage is summarised as follows:

- For long term storage, dealing with seasonal variations, it is expected that the main storage capacity will be provided by storage in salt caverns and potentially depleted oil and gas fields. Conversion of existing underground gas storage sites and the addition of new caverns specifically built for hydrogen will provide the required capacity. As per current operations, caverns will be filled with hydrogen during the low demand summer months and withdrawn in the winter season.

  Winter demand for hydrogen (for heat) will also be expected to be met by hydrogen supplies through the European interconnectors as required.

  On the basis that LNG trade remains at least during the following two decades, this will provide a known form of energy storage for conversion to blue hydrogen when required.

  Hydrogen storage as imported green ammonia has potential to provide long term storage, although it highly depends on the establishment of international trade.

- For short term storage, to meet demand variations within a day, line packing storage will provide the equivalent of at least a third of the current energy storage capacity required in consideration of 1-in-20 peak demand flows. Network reinforcement will likely be driven by velocity constraints (see Section 14) and opportunities should be taken to size pipelines to provide additional line pack capacity.

  A large number of distributed above ground storage facilities using conventional pressure vessels and potentially pipeline arrangements will be installed particularly in sections of the network with high demand (e.g. large urban areas and network sections with large variable demand industrial users).

  Peak shaving facilities could be installed to provide the additional storage capacity in aggregated form. Peak shaving facilities converting hydrogen into subcooled liquid, ammonia or LOHC could also be considered where the energy conversion penalty is deemed acceptable. The release of hydrogen should be instantaneous (nominally within one hour) and the location determined by hydraulic modelling.

  It is expected that network operation and security of supply will be more reliant on a resilient supply provided by hydrogen NTS offtake capacity bookings, potentially able to supply hydrogen at the hourly 1-in-20 peak flows in the extreme scenario.

  Assuming that appropriate large-scale storage can be developed and connected to areas of demand via a hydrogen NTS, major challenges are related to maintaining gas distribution network resilience and meet security of supply commitments on a daily basis. Replicating current network configuration, resilient supply relies on a NTS connecting multiple supplies including large scale storage and having the capacity to meet the daily demand. During the transition period when infrastructure is being developed and access to hydrogen supplies and storage are limited, the following options have been identified:

- Transition to hydrogen (2025-2030) will initiate with gas blending in some parts of the network. This will provide some flexibility to handle a range of hydrogen content (0-20 vol%). For a fixed hydrogen supply, the hydrogen content in the gas blends could vary with demand, with hydrogen content reducing during periods of high demand when additional natural gas volumes flow through the NTS offtakes. This will provide some network resilience during the very early transitional period and will avoid the need for substantial off-grid hydrogen buffer storage.
- For early transition to 100% hydrogen (2030-2040) hydrogen to the gas distribution networks will be supplied mainly from single sources, i.e. hydrogen production plants in industrial clusters, potentially made up of trains to provide aggregated baseload capacity. Sections of the network will be converted and isolated to ensure hydrogen peak flows can be met by the single supply and line pack provided by the hydrogen transmission pipelines (hydrogen NTS and LTS) and gas distribution pipelines (IP, MP, LP). Distributed above ground storage will be gradually installed as necessary close to the areas of high demand. Conversion of network sections around large industrial users supplied from the LTS with a variable demand impacting within-day storage requirements (e.g. power plants) will be dictated by industrial fuel switching.

  Seasonal demand variation (temperature sensitive load) to be handled by energy storage as LNG for the case of South Wales. For North Wales this will be expected to be initially managed by variable production from the HyNet hydrogen plants and eventually via accessing salt caverns in Cheshire. For the South West, security of supply will be met by accessing salt caverns, LNG supplies and hydrogen from European interconnectors via the hydrogen backbone.

- During full network transition to 100% hydrogen period (2040-2050) a significant infrastructure interconnecting clusters and other sources is expected to be reached, allowing security of supply from multiple sources and therefore allowing a greater reliance on the hydrogen NTS, as per current network configuration. Distributed above ground storage capacity will provide aggregated buffer capacity to provide increased network resilience, allowing conversion of larger sections of the distribution networks.

16. EXISTING WWU LTS SYSTEM AND SUITABILITY FOR CONVERSION

16.1. DESIGN SUITABILITY OF THE EXISTING NETWORK

IGEM have recently published Supplement 2 to Edition 6 of IGEM/TD/1 High Pressure Hydrogen Pipelines. This details the methodology for repurposing from natural gas to hydrogen service and follows a general approach that demonstrates compliance with the requirements for an equivalent new pipeline such as material, design factor and Building Proximity Distances (BPD). Repurposing may only take place where full maintenance records are available.

16.2. PIPELINE MATERIALS

The design factor of gas pipelines is a measure of the stress level in a pipe and is defined as the ratio of the hoop stress to the Specified Minimum Yield Stress (SMYS). Pipelines in the UK are mostly designed to a maximum of 0.72 for natural gas service. The design factor of pipelines in hydrogen service is limited to 0.5. The use of L360 (X52) or below in hydrogen service has been extensively proven in operating pressures up to 140 bar with very few reported problems *Ref (Compendium of Hydrogen Energy, Volume 2: Hydrogen Storage, Distribution and Infrastructure (2016).* This is attributed to the relatively low strength of these alloys, which imparts resistance to hydrogen embrittlement and the other brittle fracture mechanisms. Steel grades with a yield stress level higher than grade L360 (X52) have a material performance factor applied to reduce the allowable strength. In general, the majority of the LTS is constructed of steel grades of strength of L360 (X52) or lower (see maps in Figure 55 to Figure 58). Where systems are constructed of higher strength materials, then materials may require to be requalified to operate in hydrogen service at higher design factors through testing. This may not always be possible with existing in service pipelines, where spare material for testing is no longer available.

Figure 55 North Wales LTS Pipeline Material

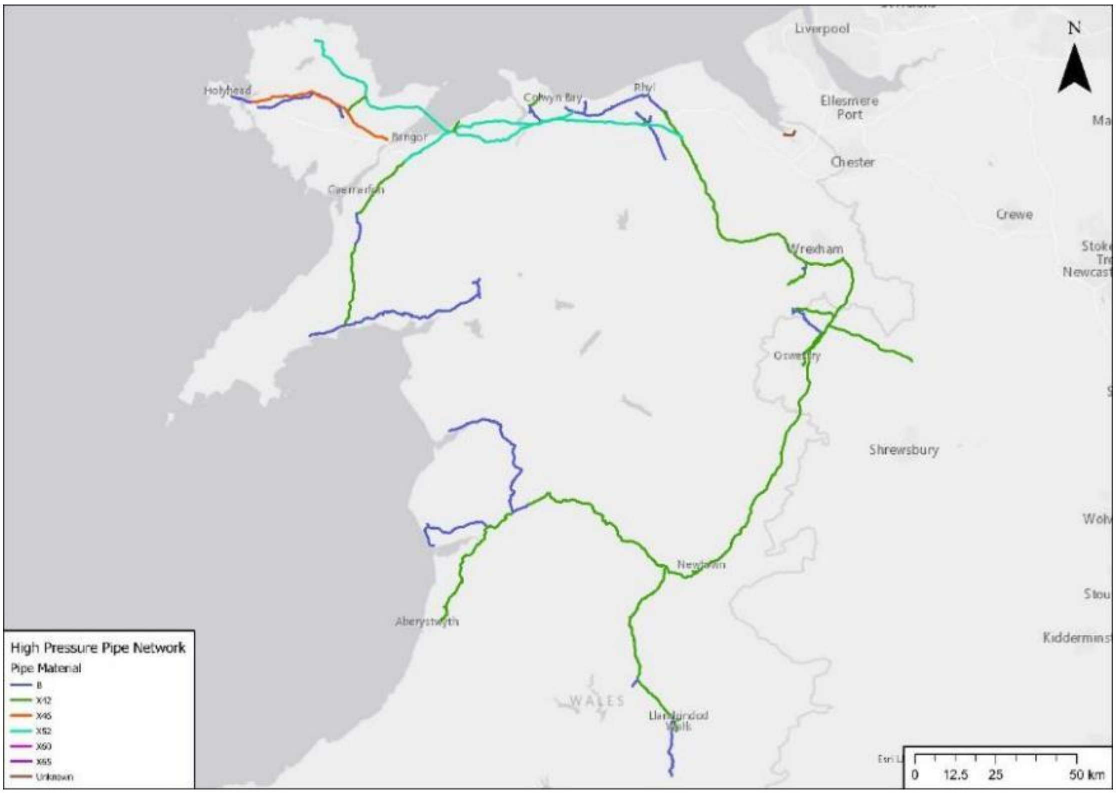


Figure 56 South Wales LTS Pipeline Material

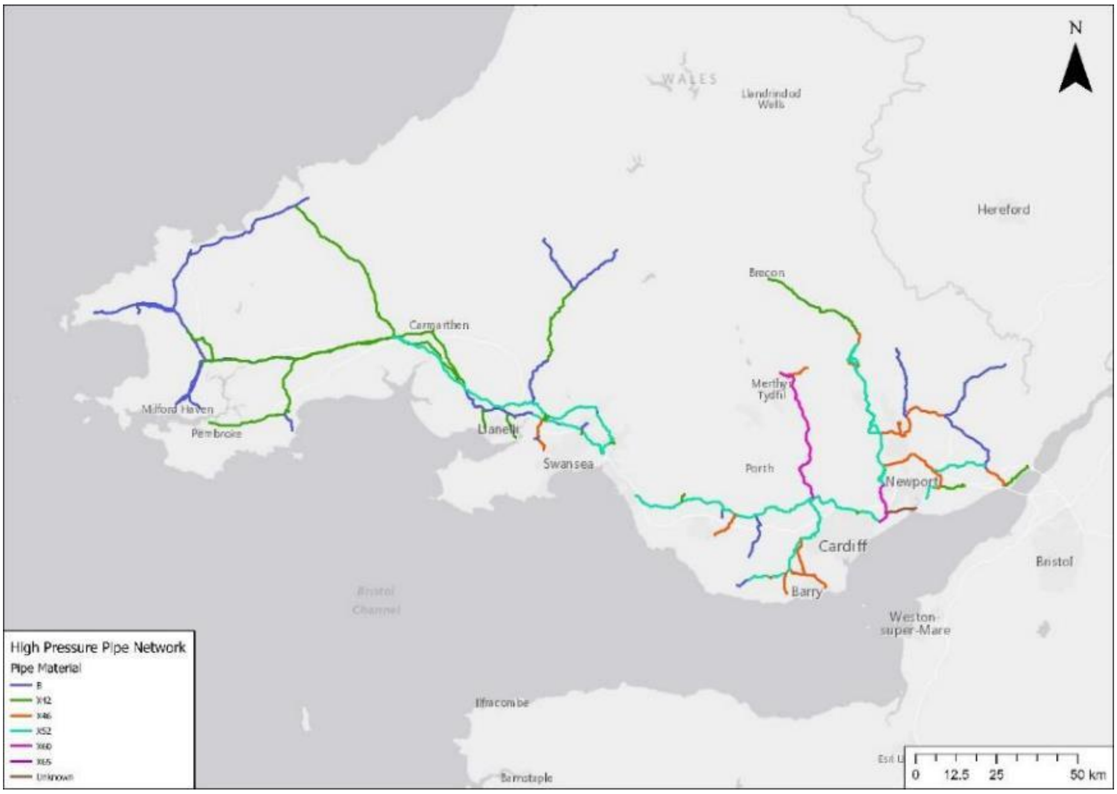


Figure 57 South West - North LTS Pipeline Material

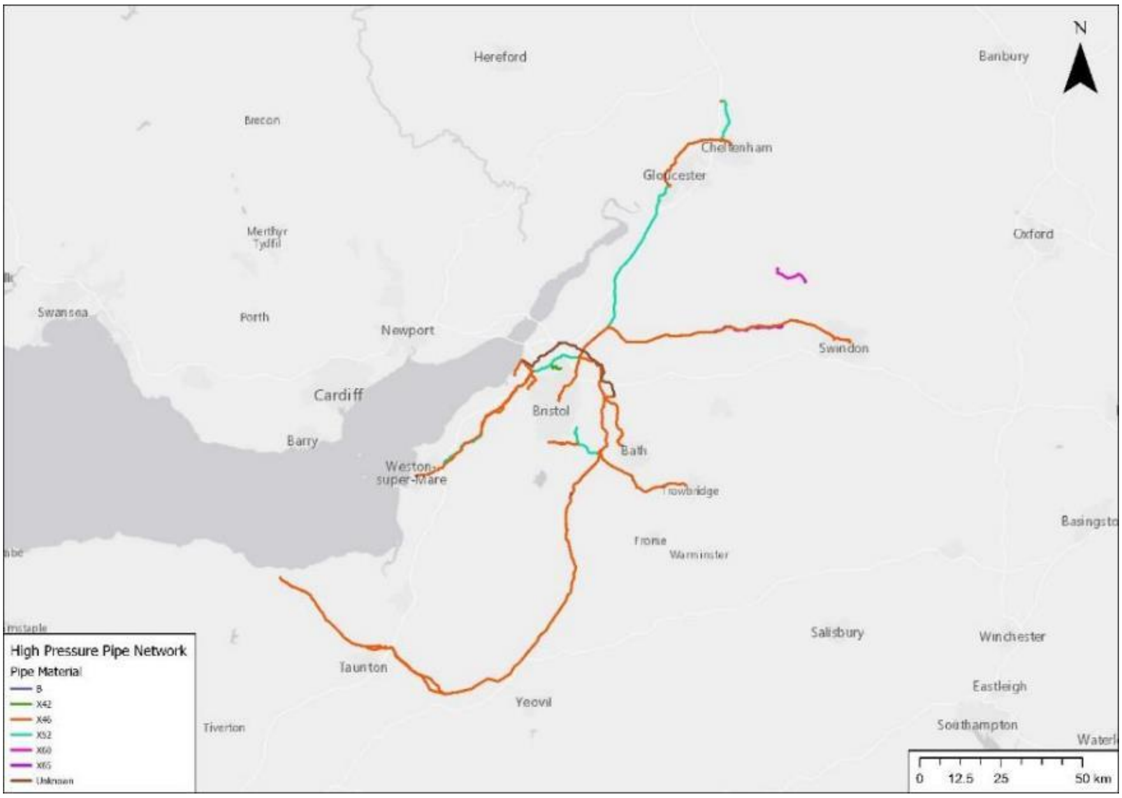
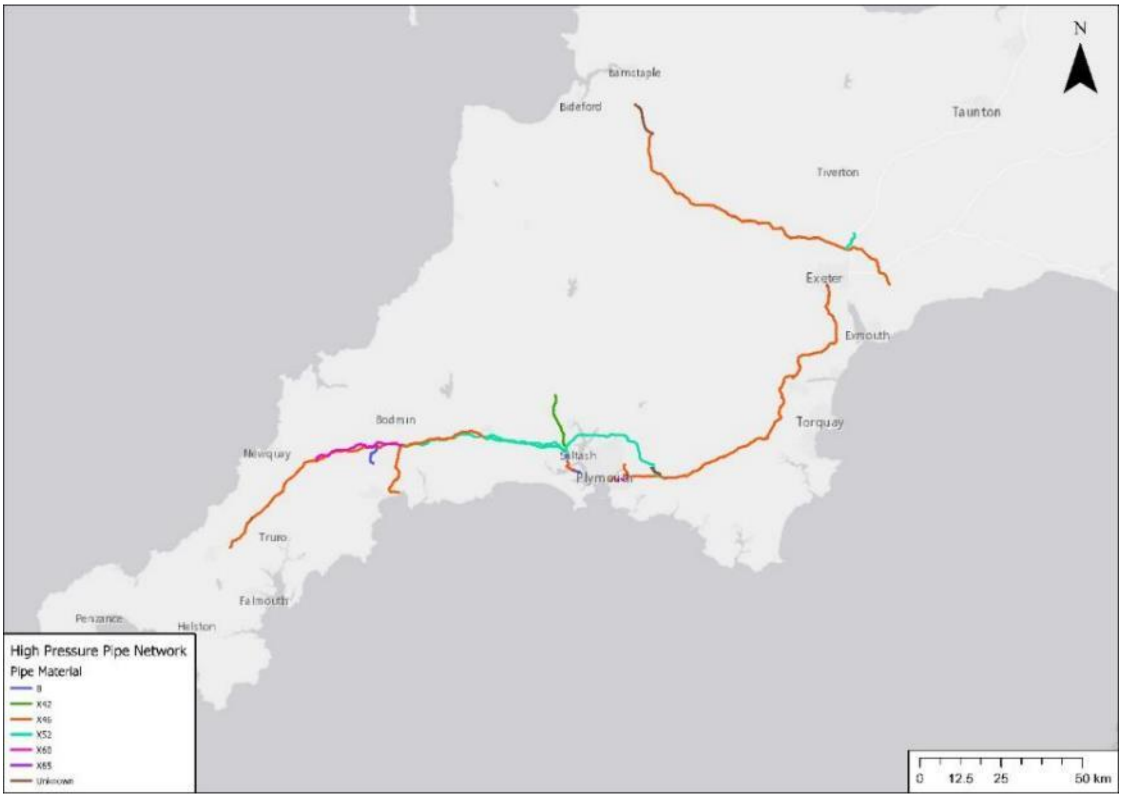


Figure 58 South West - South LTS Pipeline Material



16.3.PIPELINE AGE

The standards controlling the manufacture of pipeline materials have evolved over number of years and the material composition and manufacturing techniques closely controlled. For pipelines whose planned lifetime is close to expiring, it would be necessary to evaluate thoroughly the possible degradation of the pipe metal, i.e. a loss of its initial physical and mechanical properties responsible for ensuring its operability. Among the mechanical properties to assess are material strength and plasticity, brittle fracture resistance and fatigue strength, including fracture toughness and fatigue crack growth resistance.

The age of pipelines in the WWU supply area are shown in Figure 59 to Figure 62.

Figure 59 North Wales Pipeline Age

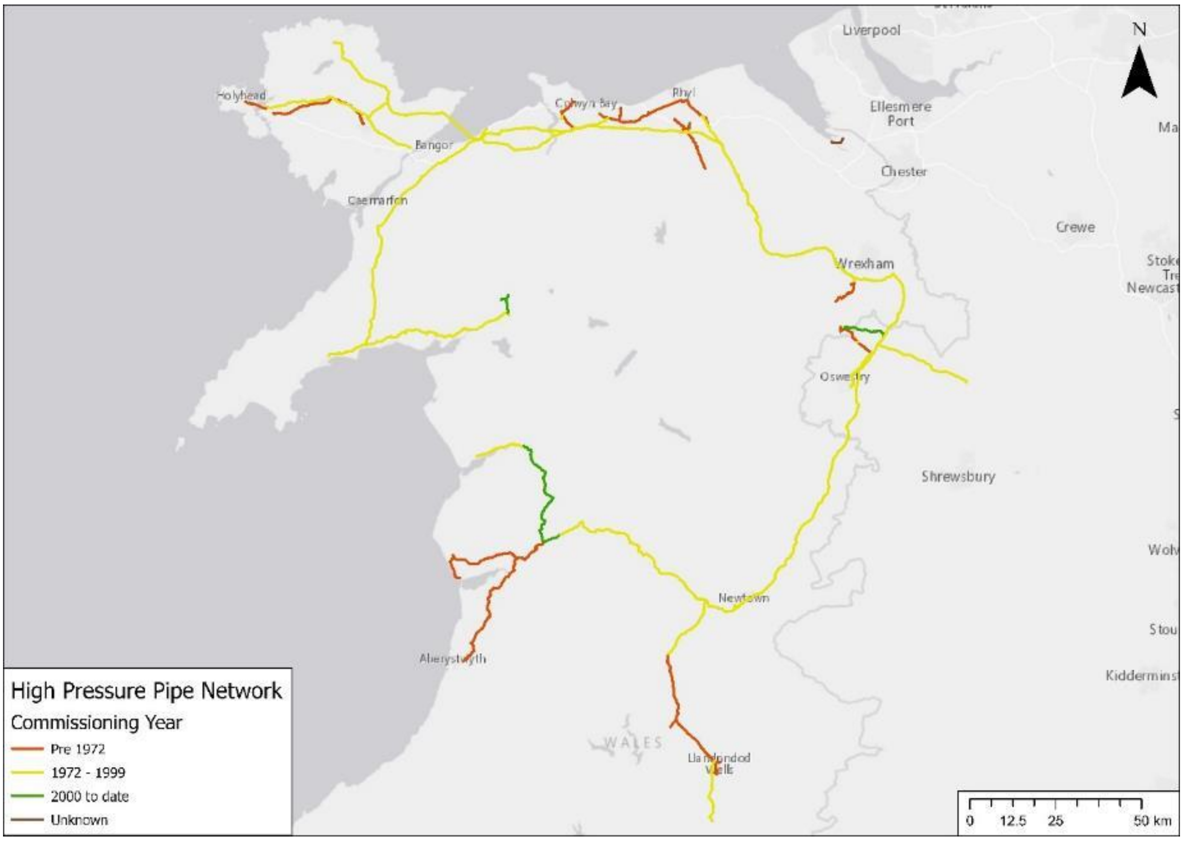


Figure 60 South Wales Pipeline Age

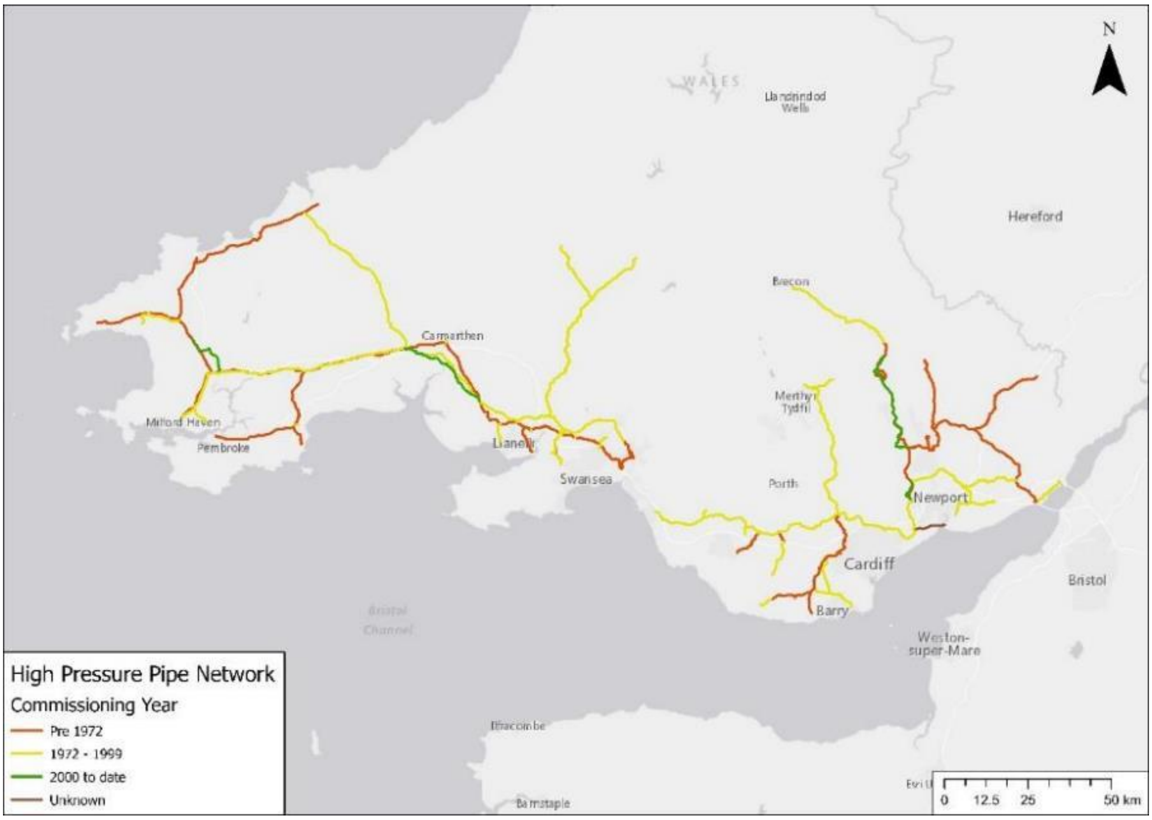


Figure 61 South West - North Pipeline Age

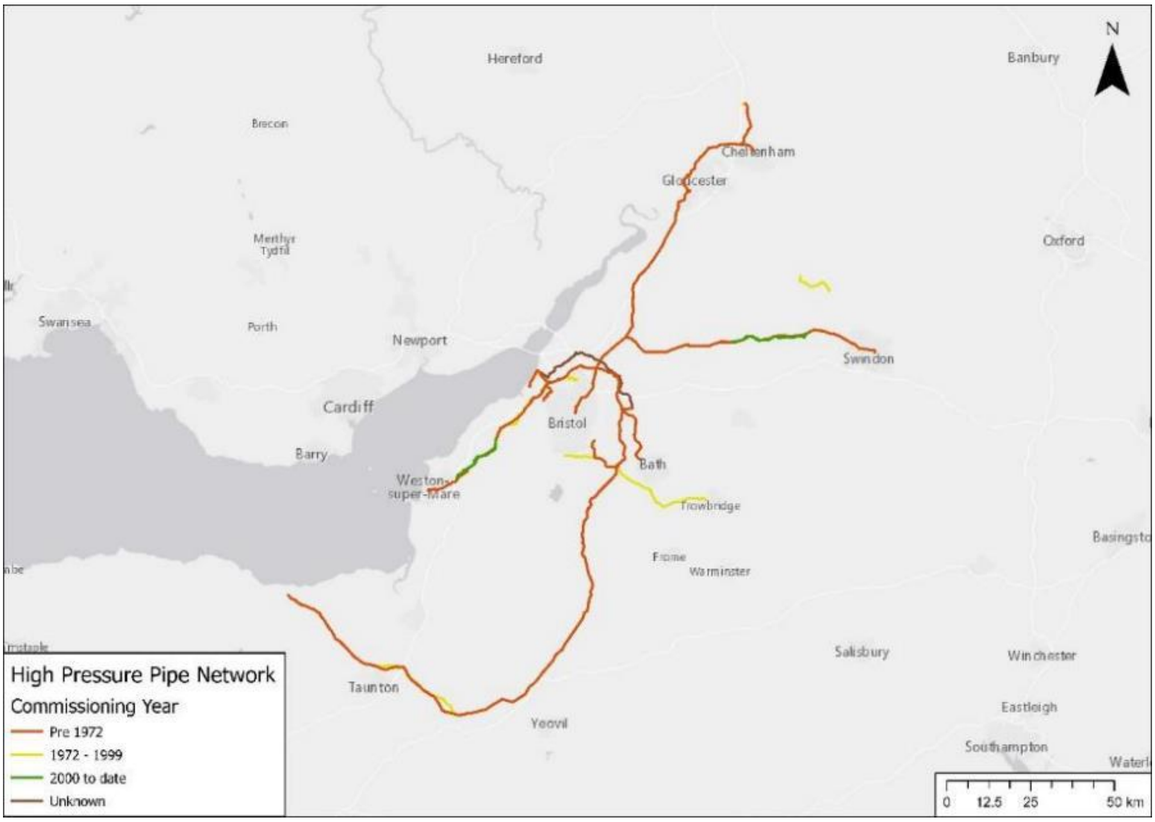
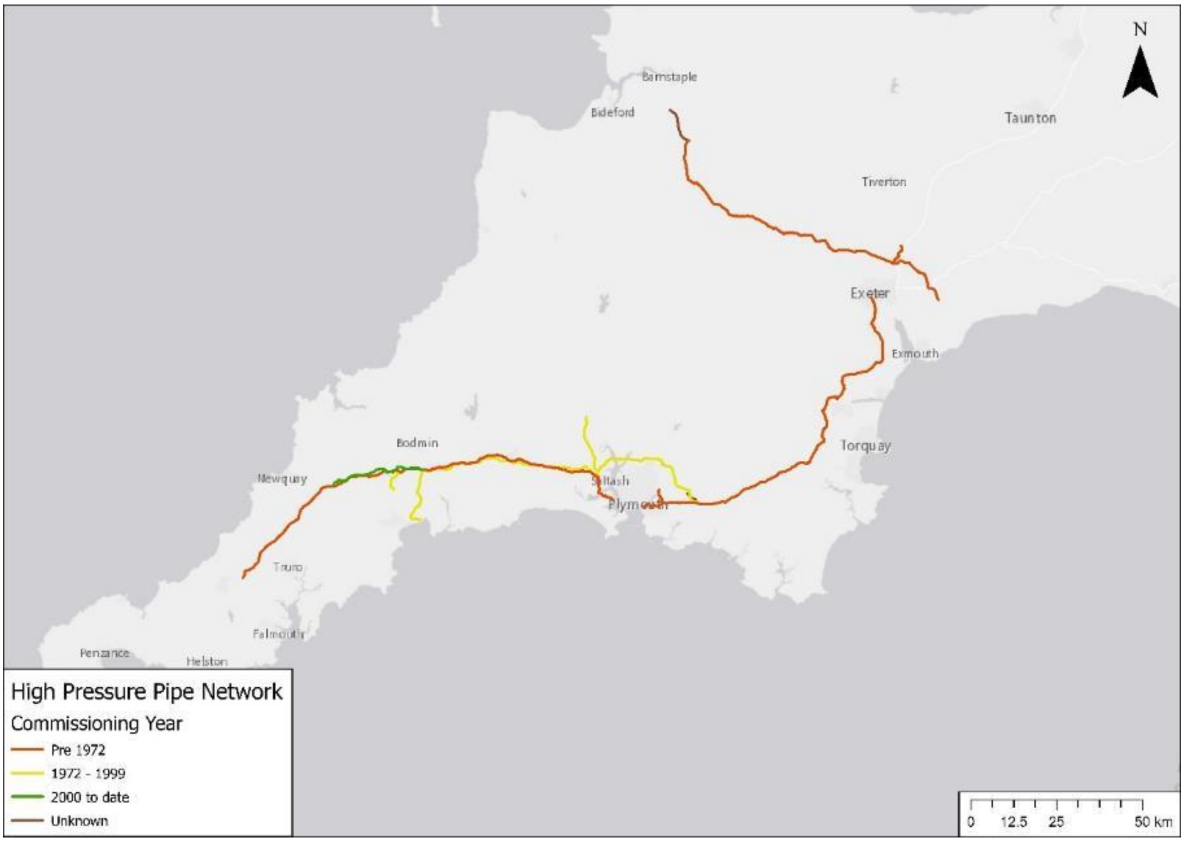


Figure 62 South West - South Pipeline Age



16.4. PIPELINES IN TOWNS GAS SERVICE

Pipelines which have been in Towns Gas service may also suffer from further degradation due to the effect of hydrogen on the pipe wall. This can lead to metallurgical change, which, in turn, leads to a sharp decrease in the resistance to the brittle fracture of pipeline steels.

Network sections which have previously used for Towns Gas in the WWU supply area are shown in Figure 63 to Figure 66.

Figure 63 North Wales – LTS Previously Used for Towns Gas

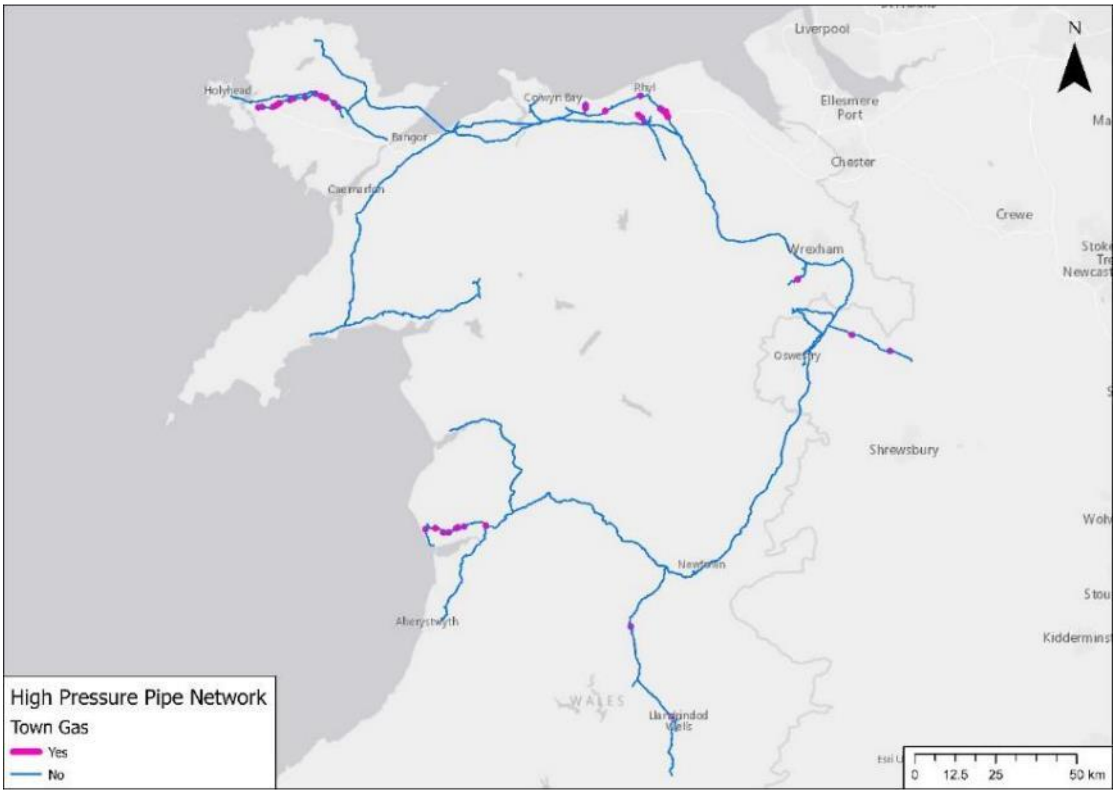


Figure 64 South Wales – LTS Previously Used for Towns Gas

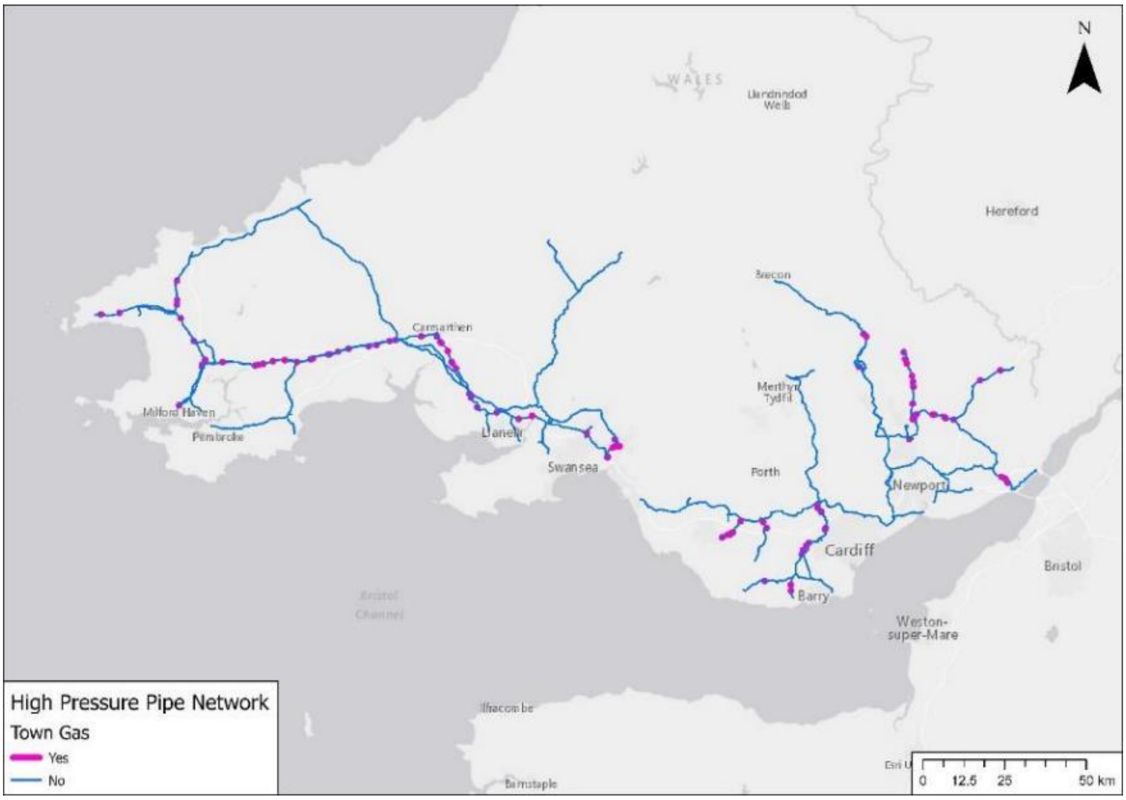


Figure 65 South West North – LTS Previously Used for Towns Gas

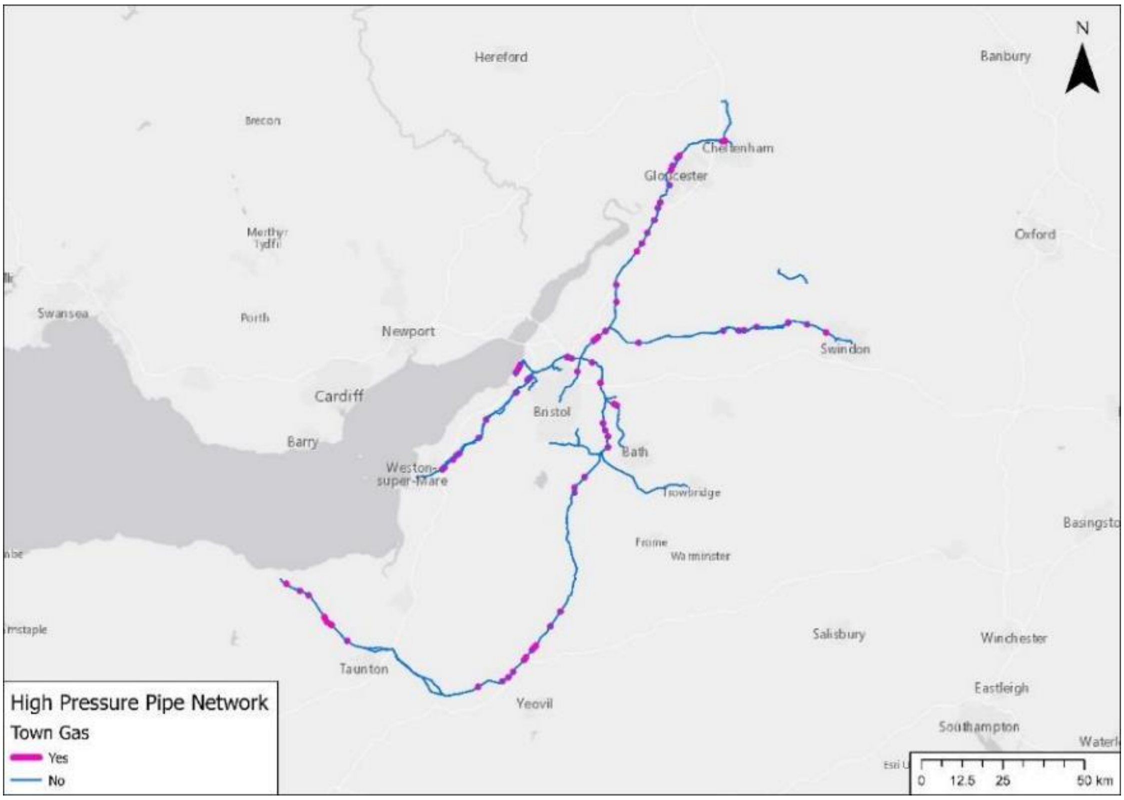
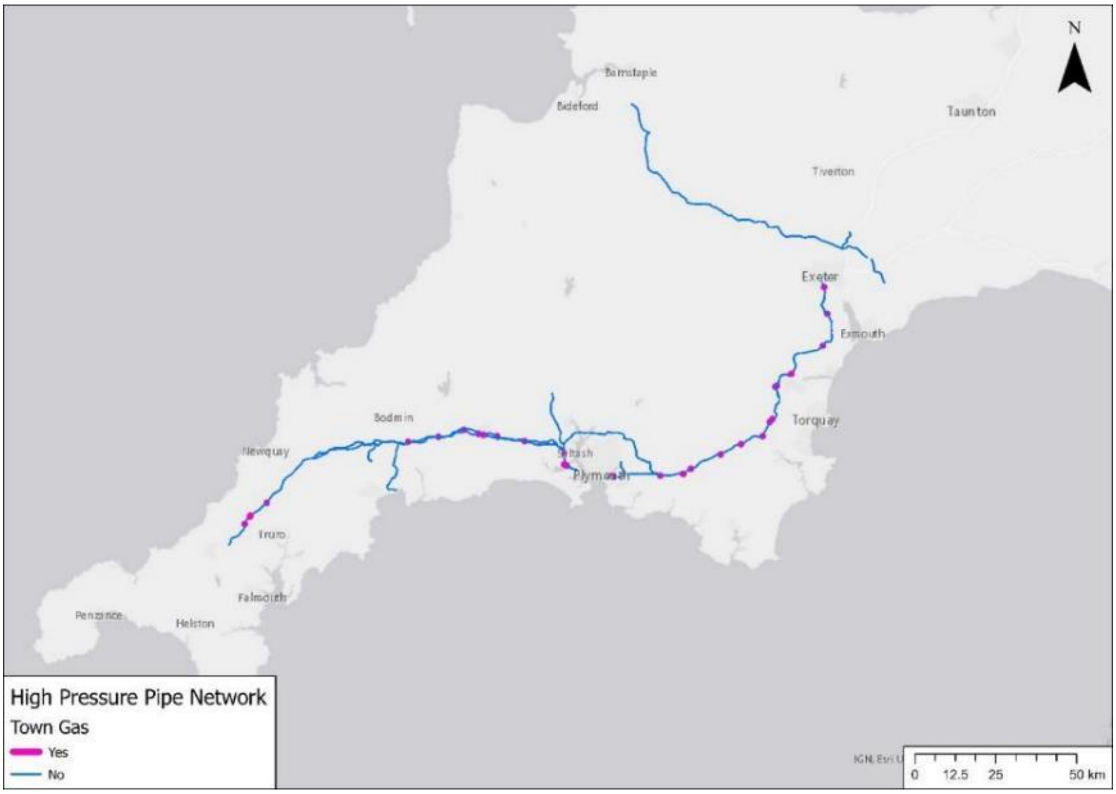


Figure 66 South West South – LTS Previously Used for Towns Gas



16.5. PIPELINE CONSTRUCTION

Construction standards controlling the quality of both materials and workmanship have improved over the years. Some early pipelines were constructed using partial penetration welds, i.e. with no weld root. Non-destructive testing of welds was also not generally undertaken on all welds in the construction of pre-1970s pipelines, with only a percentage of welds being inspected.

Modern pipeline standards require that all welds are constructed using full penetration welds and all welds are 100% non-destructively tested.

Repurposing pre-1970s pipelines to hydrogen service at the their current operating pressure may prove to be difficult where it is not possible to obtain a full set of construction and/or material records. However, where it is not possible to obtain adequate construction or material records it may be possible to still utilised these pipelines in a lower pipeline pressure tier.

16.6. PIPELINE INSPECTION

The high pressure LTS in the WWU supply area is inspected using one of two standards:

- OLI1 - Management Procedure for carrying out on-line inspection of steel pipeline systems
- OLI4 - Procedures for monitoring the condition of high-pressure steel pipelines externally

Where possible, the use of on-line inspection using the OLI1 standard is the preferred method. However, this can only be used on pipelines which have been constructed or modified to accept intelligent pigs. Intelligent pigs are used to inspect the pipeline with sensors and record the data for analysis.

Pipeline inspection frequencies are determined using a risk-based approach. In converting to hydrogen service, the frequency of inspection would need to be reviewed and potentially increased. Existing inspection reports would have to be thoroughly reviewed in order to confirm the suitability of the existing pipeline for conversion to hydrogen service.

The maps in Figure 67 to Figure 70 show which pipelines are internally inspected to OLI1 and those which are inspected to OLI4. It should be noted that a number of pipelines cannot be inspected using an intelligent pig and therefore will face more stringent requirements to enable them to be converted to carry 100% hydrogen at their current pressure rating.

Figure 67 North Wales – LTS Ability to Internally Inspect Pipeline

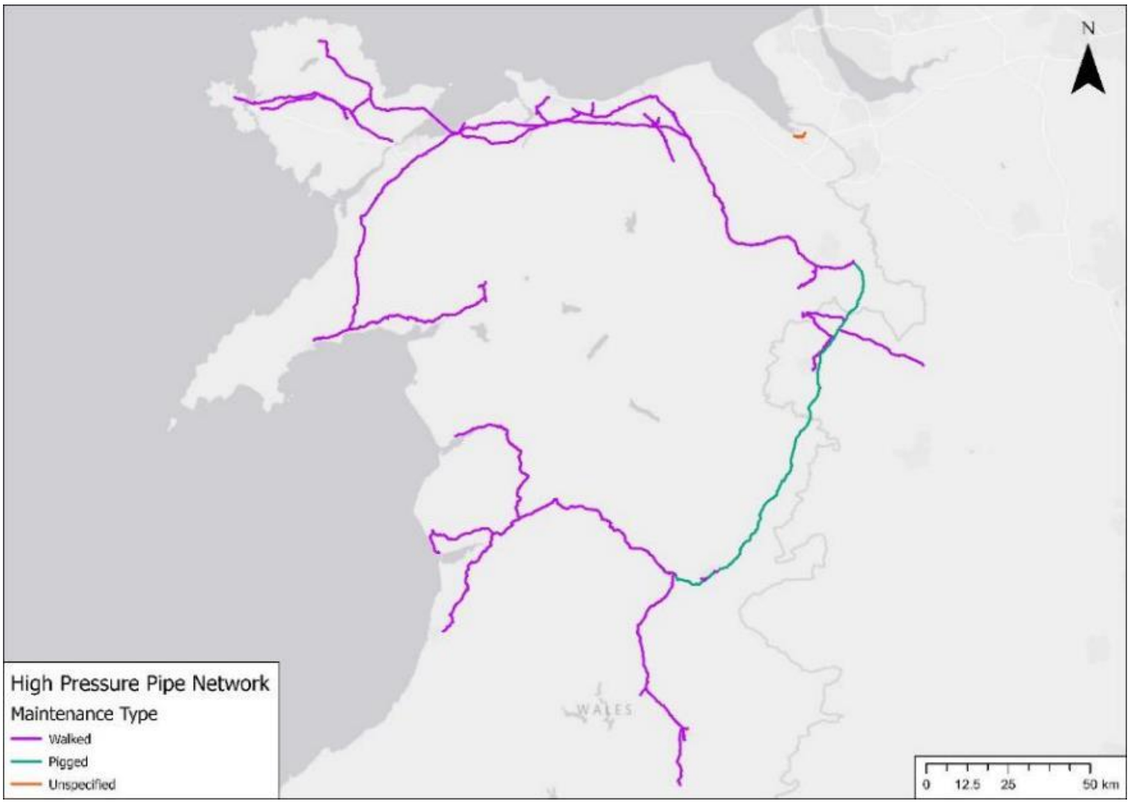


Figure 68 South Wales – LTS Ability to Internally Inspect Pipeline

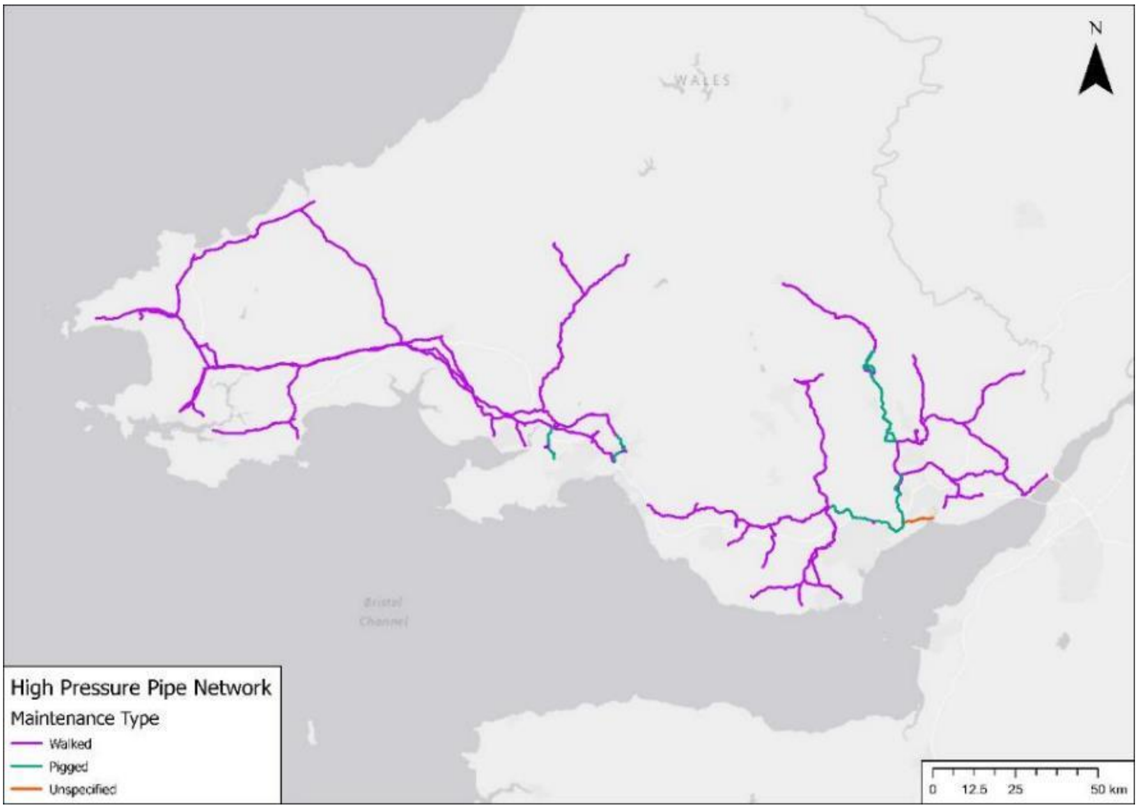


Figure 69 South West North – LTS Ability to Internally Inspect Pipeline

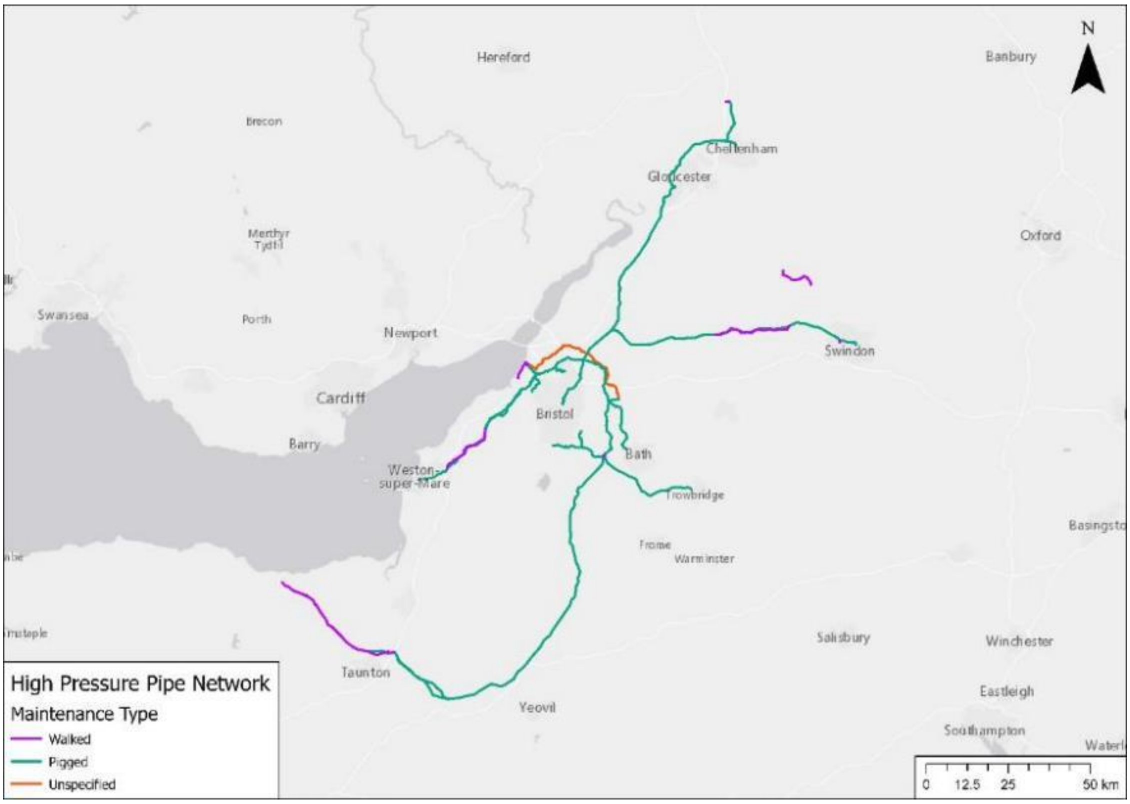
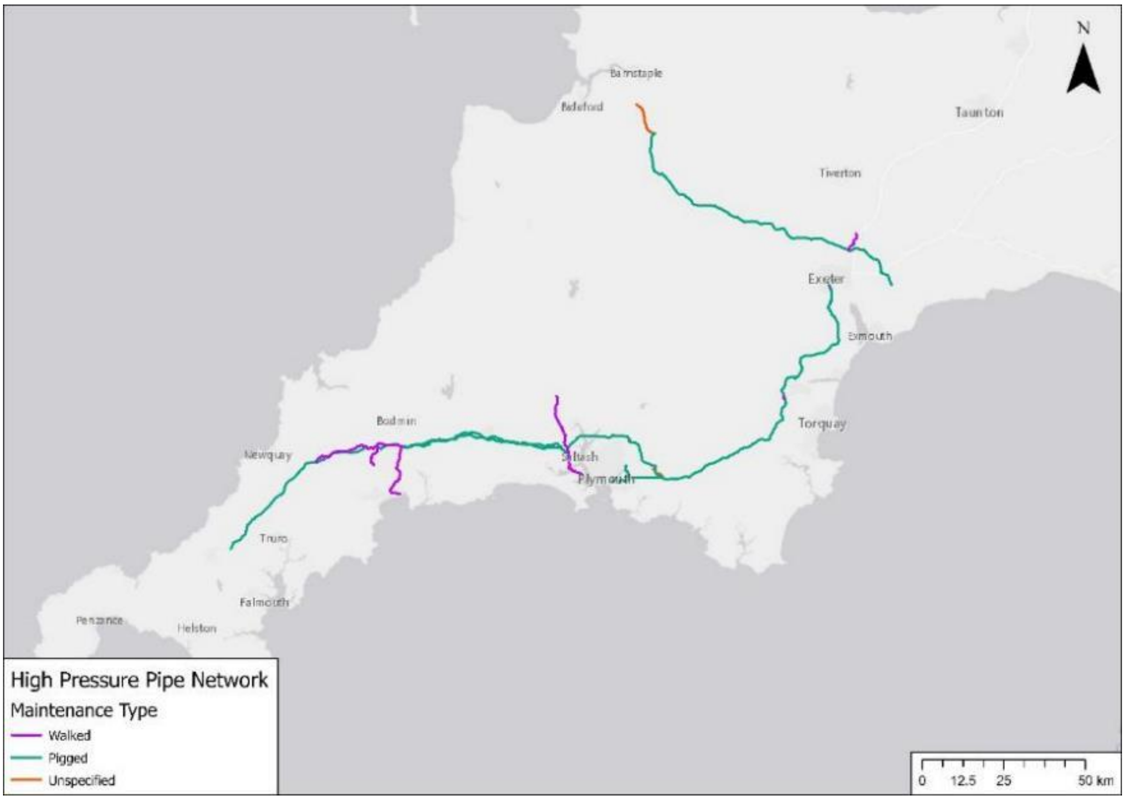


Figure 70 South West South – LTS Ability to Internally Inspect Pipeline



16.7. NETWORK CAPACITY

Due to the difference in physical properties between hydrogen and natural gas, bulk transmission of hydrogen will differ from transmission of natural gas in consideration of their relative energy densities, which for natural gas is about 3.3 times higher than hydrogen.

Increased volumetric flows of hydrogen are required to transport comparable levels of energy to natural gas. This will result in increased gas velocities in the pipeline for hydrogen, about 3.3 times the velocities of natural gas on a comparable energy flow basis. Put in a different form, where existing pipelines are converted to transport hydrogen whilst maintaining gas velocities as per current operation with natural gas, the pipeline would only be capable of transporting approximately 30% of the equivalent energy transported as natural gas. It is acknowledged that currently, pipelines operate with a peak flow resulting in gas velocities below the nominal design value of 20 m/s and therefore, a margin exists to transport energy as hydrogen above the 30% for the equivalent replacement of natural gas volumetric flows.

On the other hand, pressure losses are a function of fluid momentum which is the product of mass density and velocity squared. Mass density of natural gas is around 9 to 11 times higher than the mass density of hydrogen. This results in not too dissimilar fluid momentum for both natural gas and hydrogen, such that the energy transported as hydrogen is potentially around 80% (and higher) of the energy transported as natural gas in the converted pipeline for a given pressure loss. Again, it is expected that operating margins with respect to pipeline capacity would allow increasing hydrogen flows, potentially matching the energy currently supplied by natural gas for a given allowable pressure loss (e.g. where current peak gas flows are about 80% of the pipeline capacity).

The evaluation presented in Section 15 provides quantification of gas flows, velocities and pressure losses for representative network operating conditions and pipeline sizes. This shows that even when operation regarding hydrogen pressure losses can be accommodated by existing network capacity, gas velocities in excess of the nominal design basis 20 m/s require attention to balance erosion risk against the investment associated to network capacity reinforcement. Based on a revised risk-based pipeline integrity management strategy, higher velocities could be allowed before reinforcement is deemed necessary.

For the transport of gas blends with a hydrogen content of up to 20 vol%, the volumetric calorific value (CV) of the gas blend is about 85% of the CV of the natural gas with no hydrogen. Therefore, for a fixed gas velocity basis, the energy transported as a 20 vol% hydrogen gas blend is about 85% of the energy transported as natural gas. An increase in the volumetric flow by about 18% is required to transport the same energy as a 20 vol% hydrogen gas blend, which is likely to be accommodated by current operating margins (i.e. 18% increase in volumetric gas flow resulting in gas velocity below the design limit 20 m/s). Therefore, no issues are generally expected in terms of capacity for the transport of gas blends up to the intended hydrogen limit of 20 vol%.

16.8. SUITABILITY OF EXISTING NETWORK FOR CONVERSION

Without undertaking a detailed hydraulic analysis and having detailed specific knowledge of the integrity of the existing WWU LTS system it is difficult to estimate what specific parts of the existing system would be decommissioned or replaced in the process of system conversion from natural gas to hydrogen. The WWU scenarios modelled in ESME and ITAM, indicate that in the high electrification scenario, which of the three scenarios considered in this study could be considered the worst case for the volume of hydrogen requiring gas transportation in the future, only 6% of domestic and commercial meters would be decommissioned in Wales and 16% of domestic and commercial meters in the South West. The majority of these meter are anticipated to be in the centre of the major conurbations, where district heating becomes the main source of domestic heat load under these scenarios.

As mentioned, above where existing pipelines are converted to transport hydrogen whilst maintaining gas velocities as per current operation with natural gas, the pipeline would only be capable of transporting approximately 30% of the equivalent energy transported as natural gas. The requirement during conversion for dual systems, one supplying hydrogen and one supplying natural gas, would probably mean that up until the point of full conversion the extent of the current system is likely to remain virtually unchanged as hydrogen is supplied via a new LTS pipeline system. At conversion, several current LTS pipelines may have to be derated, decommissioned or replaced, which would be dependent on a number of factors with regard to pipeline integrity including piggability, age, material grade etc or due to flow assurance constraints.

Prior to conversion to hydrogen a formal assessment of the suitability of the existing pipeline network and its associated installations is required to be undertaken. This also needs to include an assessment of the risks posed on the surrounding population by repurposing the existing network to hydrogen.

17. REGIONAL CONCEPTUAL PLANS

17.1. GENERAL METHODOLOGY

17.1.1. OVERARCHING CONVERSION STRATEGY

As established in the overarching decarbonisation strategy, the first customers in the start-up phase of a climate neutral hydrogen industry are large industrial consumers with extensive on-site energy usage that can be replaced by hydrogen. A successful start-up phase with this target group is a central building block for establishing hydrogen demand and supply.

Once a large industrial consumer has converted to hydrogen, then hydrogen production capacity can be upscaled such that hydrogen can be distributed to the locality via the distribution gas network, either in the form of a natural gas blend (up to 20 vol% hydrogen content) or as 100% hydrogen.

As demand for hydrogen increases, and to ensure a security of supply, individual hydrogen production facilities will be joined together either locally via a transmission network developed as part of the GB hydrogen backbone or a regional hydrogen network. The regional analysis, particularly for South Wales made evident the benefits for a hydrogen local transmission system, in anticipation of the development of the hydrogen backbone.

17.1.2. WWU SCENARIO ANALYSIS

For the Regional Decarbonisation Pathways' Strategic Plans, hydrogen and natural gas consumption data was generated and analysed, to enable a picture of the switch over to be developed for each region and scenario. The WWU scenarios show that hydrogen production and consumption by industry generally starts between 5 and 10 years in advance of hydrogen being supplied to the local distribution network.

Based on the hydrogen requirements in the scenario outputs, potential hydrogen production locations were agreed and major industrial users were identified and located, the hydrogen demand on the distribution network was split as per the current offtake demand profile based on historical operational data. This allowed the hydrogen network distribution consumption to be apportioned to each offtake in similar percentage quantities to present day supply.

It should be noted that only the WWU scenario gas and hydrogen consumption / production outputs were analysed and that no account was taken of users' fuel switching ie liquid fuels moving to electric etc.

17.1.3. NEW PIPELINE ROUTING

For all WWU scenarios new hydrogen transmission pipelines were predominantly routed along existing NTS or WWU pipeline route corridors. Where this was not possible, a straight-line route was adopted for simplicity at this stage for indicative purposes. It should be noted that this approach was adopted to provide a high-level estimate of the length new pipeline required and no detailed pipeline routing was undertaken. Therefore, pipeline routes may be longer than those given in this report.

17.2. WALES

17.2.1. GENERAL

The WWU gas network in Wales comprises of approximately 2,500 km of transmission pipelines (above 7 barg) and more than 12,700 km of distribution network. The system is currently fed via four offtakes from the NTS, three in South Wales and one in North Wales which also supplies mid Wales.

From the WWU Strategic Plan scenarios, industry will potentially start the conversion to hydrogen from circa 2025, with supply to the gas distribution network in 2030 for the HYD and BAL scenarios and in 2035 for the ELE scenario. Due to the different timelines on the role-out of hydrogen, the BAL and HYD scenarios will have to start the planning process five years earlier. About 95% of the non-industrial gas meters are estimated to be retained by 2050 by the three scenarios, so the requirement for hydrogen pipelines will broadly be the same for all scenarios.

In Wales it is estimated that approximately 600 km of new LTS hydrogen pipeline will be required during conversion. Also, an additional 75 km of new natural gas pipeline is required to either feed hydrogen production facilities or provide cross connections within the network. It should be noted that without undertaking a detailed conversion strategy and hydraulic analysis these lengths are indicative.

17.2.2. SOUTH WALES

There are three offtake locations feeding gas into the local South Wales area. These are:

- Dyffryn – generally feeding Swansea and West Wales
- Gilwern – generally feeding the central area of South Wales from Port Talbot to the East of Cardiff
- Dowlais – generally feeding Newport and South East Wales including Chepstow

Major consumers (https://naei.beis.gov.uk/data/map-large-source) of energy and CO_2 producers include:

- Valero - Pembroke
- RWE - Pembroke
- Tata - Port Talbot (including Power Station, Blast Furnaces, Sinter Plant, Coke Ovens and Rolling Mill)
- Tarmac Cement and Lime Limited - Aberthaw

Valero and RWE in Pembroke both benefit from being in close proximity to LNG importation facilities, which could supply a regular source of natural gas which is required to manufacture blue hydrogen. Being a port also allow for easy transportation of CO_2 to its final disposal location.

Tata Steel at Port Talbot benefits from the site being in relatively close proximity to the gas NTS and again has port facilities to allow for easy transportation of CO_2 to its final disposal location.

To the east of Port Talbot, the NTS in South Wales is increasingly routed inland – which is less optimal for blue hydrogen production where it is benefit to co-locate hydrogen production and CO_2 export facilities.

It is therefore envisaged that hydrogen production in South Wales will start in Pembroke and Port Talbot, initially feeding the major industrial users and providing hydrogen to blend into the NTS. In order to ensure a security of supply the individual producers of hydrogen will be joined via a new hydrogen transmission pipeline from Pembroke to Port Talbot, feeding into the local WWU Dyffryn network at existing Pressure Reduction Installations (PRI) and Governor locations to allow for the conversion of the distribution network in the local supply area.

Any additional large industrial consumers can be converted as the new hydrogen transmission pipeline is expanded to reach their location.

At Dyffryn, the new hydrogen transmission pipeline splits with one leg paralleling the existing Feeder 2 and eventually reaching Tewkesbury and one leg feeding Cardiff and Barry. The new leg paralleling the Feeder 2 could be sized to enable hydrogen produced in South Wales to be exported to England. This pipeline could ultimately join with National Grid's Project Union arriving from west.

As production is ramped up it is envisaged that the new hydrogen transmission pipeline, will be extended to West Cardiff and Barry. In the Barry area there are a number of large industrial energy users, which may justify the potential location of a blue hydrogen facility. The blue hydrogen facility would require a dedicated supply connection to the existing NTS natural gas system to the north and the availability of port infrastructure for the export of captured CO_2 by ship.

As the new hydrogen network reaches both Gilwern and Cardiff the Cardiff area, the existing gas network can then be converted to hydrogen.

Figure 71 details the extent of the proposed new hydrogen and natural gas pipelines required by 2050 for the South Wales area.

Figure 71 South Wales Hydrogen End State Conceptual Plan – All Scenarios

17.2.3. NORTH WALES

There is one offtake location feeding gas into the local North Wales area. This comprises two Pressure Reduction Installations, one feeding the North Wales Coast area and one feeding the Mid Wales area.

Major energy users (https://naei.beis.gov.uk/data/map-large-source) and CO_2 producers include:

- Castle Cement - Padeswood
- Deeside Power – Deeside Industrial Park – Note: now only provides stability services to the National Grid and is no longer producing power
- Uniper UK Limited - Connah's Quay
- Kronospan - Chirk

It should be noted that there is also a potential large energy user at Airbus Broughton which although located in Wales is currently supplied gas from the Cadent network.

The HYD and BAL WWU scenarios show that North Wales will be a proposed location for an electrolytic hydrogen facility, Connah's Quay is a proposed location for such a facility due to its proximity to the electrical national grid. However, given the close proximity of HyNet to the major industrial user in North Wales, it is assumed that the first hydrogen to be supplied to North Wales is likely to be produced from the foundational HyNet facility being developed at Stanlow.

It is envisaged that as a first stage in conversion hydrogen will initially be fed to the major industrial users in the Deeside area including Uniper, Tata, Castle Cement and Knauf Insulation by a new hydrogen pipeline from Stanlow. Given the relatively close proximity of a number of major energy users in North Wales to Stanlow and the short length of new hydrogen pipeline required to feed them from Stanlow. These major energy users may choose to convert to hydrogen in advance of conversion of the distribution system.

Following the first stage conversion of major energy users in the Deeside area, the new hydrogen pipeline from Stanlow to Deeside will be extended to Maelor. This new pipeline will feed into the local North Wales coast network at existing PRI and Governor locations to allow the start of conversion of the distribution network in the local supply area.

From Maelor the new hydrogen pipeline network would be further extended to supply hydrogen to locations where it can be fed into the network at strategic locations to aid conversion. One spur from Maelor would tie-in to the existing supply network near Bodfari allowing the system to be split into discrete areas - paving the way for conversion of the North Wales coast system. It has been assumed for the Strategic Plan modelling that Wylfa is the location of a Nuclear Cogeneration hydrogen production facility and when constructed in the 2040s would be connected via a new hydrogen pipeline to the existing LTS on Anglesey via a short spur. As hydrogen production is ramped up, an additional hydrogen spur would be required to the mid Wales system extending from Maelor to near Machynlleth. A spur from this pipeline would be required to feed Kronospan near Chirk should they choose to convert to use hydrogen.

The relatively close proximity of the North Wales supply area to the gas storage facilities in Cheshire will allow this local supply area to have access to these facilities for seasonal and diurnal storage requirements. Figure 72 and Figure 73 detail the extent of the proposed new hydrogen and natural gas pipelines required by 2050 for the North Wales area.

Figure 72 North Wales Hydrogen End State Conceptual Plan – ELE Scenario

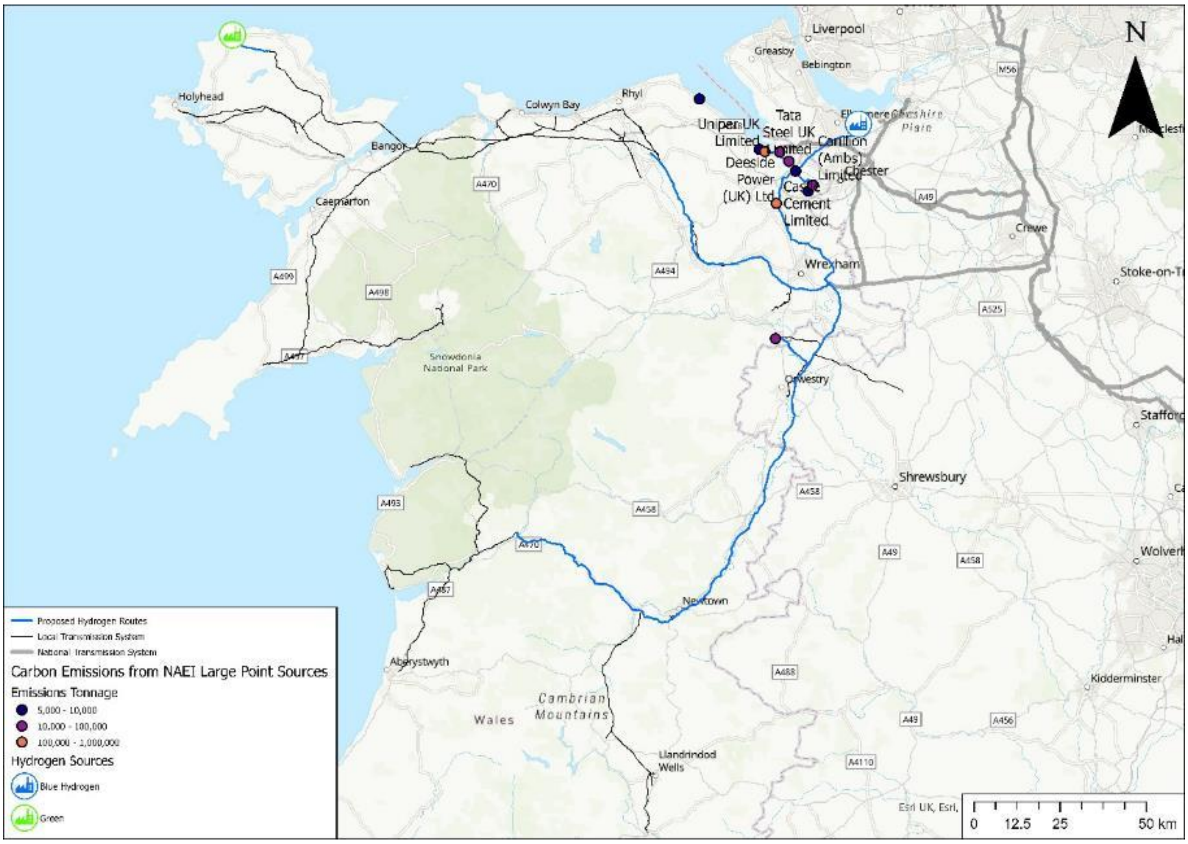
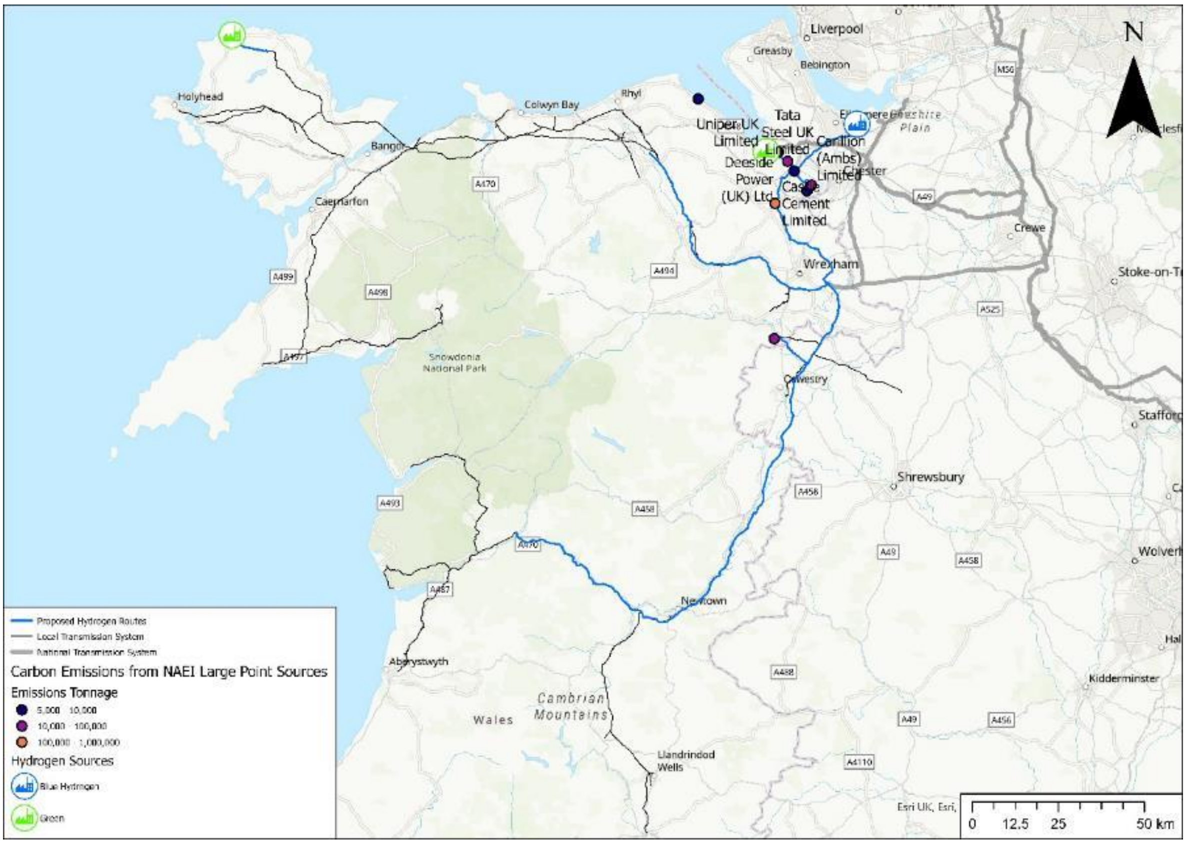


Figure 73 North Wales Hydrogen End State Conceptual Plan – BAL and HYD Scenarios



17.3. SOUTH WEST

17.3.1. GENERAL

The WWU gas network in South West comprises of approximately 1,475 km of transmission pipelines (above 7 barg) and more than 19,700 km of distribution network. The system is currently fed via thirteen offtakes from the NTS. Eight offtakes supply over 90% of gas to the region, mainly feeding the major urban conurbations in the distribution zone. The system is far less integrated than that in Wales and there are a number of offtakes providing the a gas supply to individual areas including:

- Ross feeding the Forest of Dean
- Evesham feeding the West Cotwolds
- Cirencester feeding parts of Swindon and Cirencester
- Littleton Drew feeding Chippenham
- Coffinswell feeding parts of Torbay

The WWU Strategic Plan scenario outputs envisage that industry will potentially start the conversion to hydrogen from circa 2025, with supply to the gas distribution network in 2030 for the HYD and BAL scenarios and in 2035 for the ELE scenario. Due to the different timelines on the role-out of hydrogen, the BAL and HYD scenarios will have to start the planning process five years earlier. About 84% of the non-industrial gas meters (81% for the ELE scenario) are estimated to be retained by 2050, so the requirement for hydrogen pipelines will broadly be the same for all scenarios.

In the South West, it is estimated that approximately 675 km of new LTS hydrogen pipeline would be required during conversion. Also, an additional 30 km of natural gas pipeline is required to either feed hydrogen production facilities or provide cross connections within the existing network. It should be noted that without undertaking a detailed conversion strategy and hydraulic analysis these lengths are indicative.

17.3.2. NORTHERN SOUTH WEST

There are nine offtake locations feeding gas into the local area. Four PRIs provide gas to discrete supply areas. The supply to the Forest of Dean via the Ross offtake could be treated as an extension of the conversion of the South Wales area. Since South Wales would be expected to eventually become a net exporter of hydrogen from the region, hydrogen to the adjacent northern South West area would be supplied via the new LTS hydrogen pipeline paralleling the existing Feeder 2 route, on reaching England, the new LTS hydrogen pipeline would be integrally connected to the overall hydrogen NTS infrastructure.

Major energy users (https://naei.beis.gov.uk/data/map-large-source) and CO2 producers include:

- Seabank Power – Avonmouth
- Suez Recycling and Recovery - Avonmouth
- Lucozade / Ribena – Forest of Dean
- ETEX Building - Portbury

The energy requirements of the major emitters in this area are considerably lower than for major emitters in South Wales.

It has been assumed for the Strategic Plan modelling that initial hydrogen production is located in the Avonmouth area to take advantage of the proximity of the existing NTS for natural gas supply and a port to allow for the transportation away of carbon dioxide. Hydrogen production in Avonmouth area will initially feed the local major industrial users.

A new LTS hydrogen transmission pipeline, would be required to be constructed from Avonmouth north to Tewkesbury to feed the major users in the Gloucester and Cheltenham area. It is envisaged that as South Wales would become a net exporter of hydrogen, the new South Wales hydrogen LTS pipeline could be extended to Tewkesbury to eventually allow the cross connections of the system and ensure security of supply from multiple hydrogen producers. Any additional large industrial consumers could be converted as the new hydrogen LTS system reaches their location.

The new hydrogen LTS pipeline would be extended south from Avonmouth to connect to industrial users south of the river Avon and eventually provide a supply to Weston Super Mare.

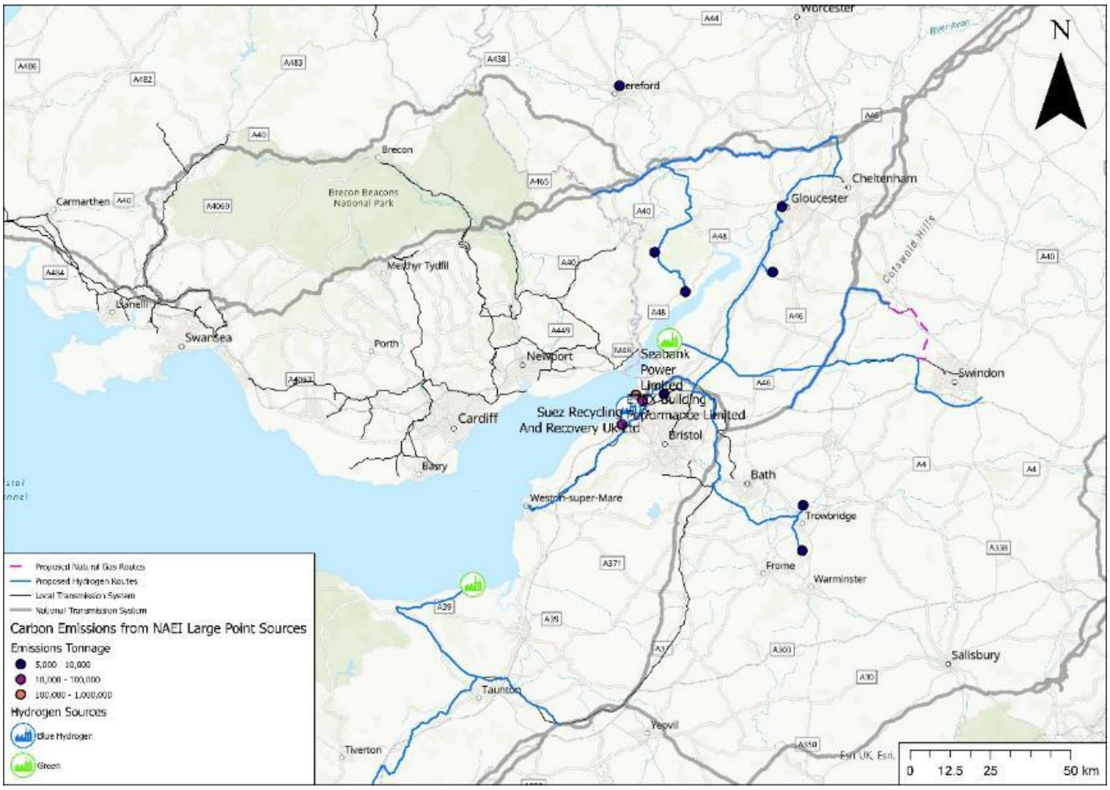
At Heath End, a new hydrogen pipeline spur paralleling the existing LTS would extend to Swindon. In order to effectively convert the Swindon area an additional natural gas pipeline may be required from the Cirencester system to allow for the dual supply of natural gas and hydrogen to the Swindon area during the conversion process. Also at Heath End, a new hydrogen LTS pipeline spur would connect the Nuclear Cogeneration hydrogen production facility at Oldbury as considered in scenarios modelled in ITAM.

Two additional new LTS hydrogen spurs would connect to the Heath End - Swindon Pipeline, one to the existing offtake at Chippenham and the other to Cirencester, to allow conversion of these supply areas.

As natural gas becomes less available on the NTS, a new hydrogen pipeline would be required from the Ross on Wye offtake to the major industrial users in the forest of Dean and to convert the locality.

It has been assumed for the Strategic Plan modelling a further Nuclear Cogeneration hydrogen production facility is proposed at Hinkley Point and this will feed a new hydrogen pipeline connecting to the proposed new southern hydrogen LTS pipeline and a new hydrogen cross connection to the system feeding Barnstaple. This would also allow hydrogen to be fed into the existing LTS pipeline that feeds north towards Ilchester. Figure 74 details the extent of the proposed new hydrogen and natural gas pipelines required by 2050 for the Northern South West area.

Figure 74 South West – North Hydrogen End State Conceptual Plan – All Scenarios



17.3.3. SOUTHERN SOUTH WEST

There are four offtake locations feeding gas into the local area. These are:

- Aylesbeare – generally feeding the pipeline to Barnstaple
- Kenn – generally feeding central Exeter and the south Devon coast
- Coffinswell – feeding a electricity peaking facility and parts of Torbay
- Choakford – feeding Plymouth and Cornwall

Major energy users (https://naei.beis.gov.uk/data/map-large-source) and CO2 producers include :

- Langage Power - Plymouth
- Imerys - Par

The energy requirements of the major emitters in this area are considerably less those in the northern part of the South Western region.

It has been assumed for the Strategic Plan modelling that hydrogen production is located in the vicinity of the Langage Power plant to the west of Plymouth to take advantage of the proximity of the NTS for natural gas supply and a port to allow for the transport away of captured carbon dioxide.

Hydrogen would be produced in the Langage area, to initially feed the few major industrial users in the South West area. However, if hydrogen production is first established in the South Wales area, then in practice hydrogen supply to the South West could be realised by increasing existing production in South Wales combined with extension of the LTS hydrogen pipeline to supply the southern South West area.

Assuming that hydrogen production takes place at Langage, a new hydrogen LTS pipeline, would then need to be constructed south to feed the major users in Plymouth and Cornwall. The new hydrogen pipeline could extend as far as Indian Queens, where a power station is located and currently provides essential voltage and frequency regulation services to the electricity grid.

Heading north a new LTS hydrogen pipeline would parallel the existing NTS and LTS connecting to the major industrial users in the Exeter area and eventually connecting to the new hydrogen pipeline connecting to the proposed Nuclear Cogeneration hydrogen production facility at Hinkley Point. Figure75 details the extent of the proposed new hydrogen and natural gas pipelines required by 2050 for the southern South West area.

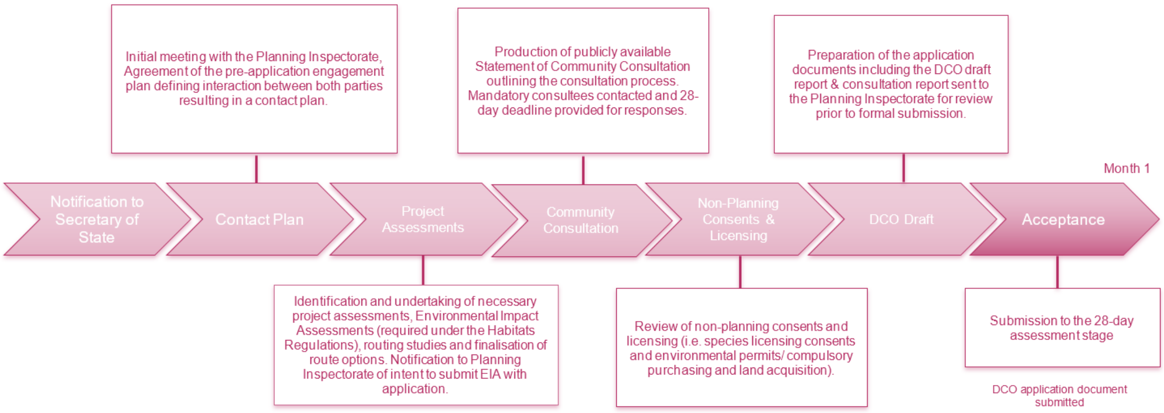
Figure 75 South West – South Hydrogen End State Conceptual Plan – All Scenarios

17.4.PLANNING REQUIREMENTS FOR THE NEW HYDROGEN NETWORK

There are number of factors that should be considered in order to fully understand the Planning, Design, Procurement and Construction timeline for a new pipeline. In England and Wales for pipelines of lengths above 16 km, the project is classified as a Nationally Significant Infrastructure Project (NSIP), requiring a Development Consent Order (DCO) under the Planning Act 2008. The process is onerous and is likely to take a minimum of 2 to 3 years to complete and receive the approval of the Secretary of State.

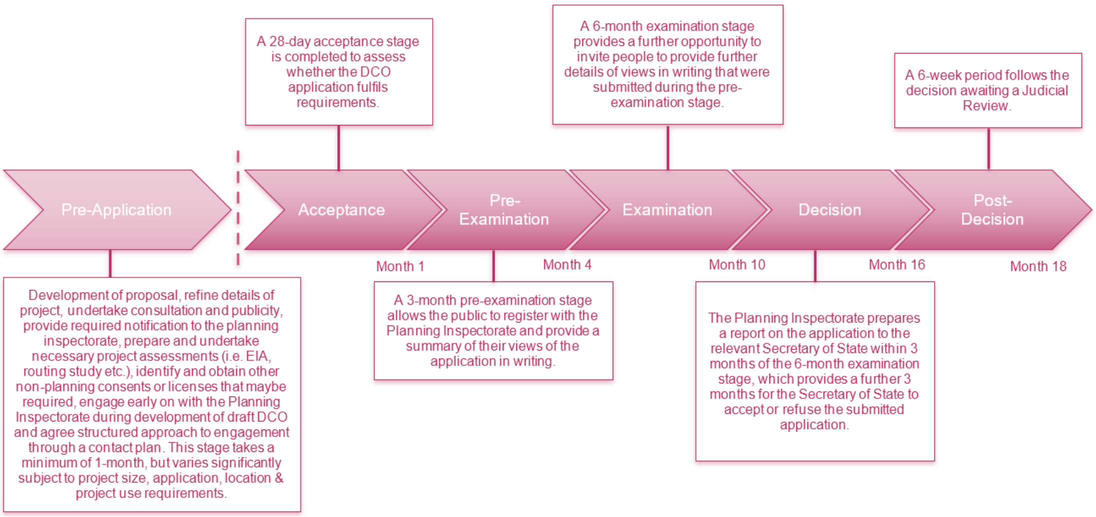
The application process can be split into two phases: Pre and Post application. The Pre-Application phase will take between 6 to 12 months duration. Figure 76 details the relevant steps.

Figure 76 DCO Pre-Application Process



The Post- Application phase will take a minimum of 18 months and the relevant steps are detailed in Figure 77.

Figure 77 DCO Post-Application Process

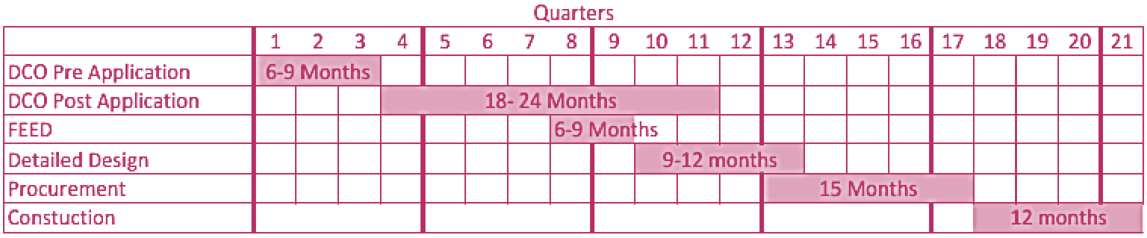


Front End Design (6-9 months) can run concurrently with the DCO application and although Detailed Design (9-12 months) can start towards the end of the DCO process, it would be unwise to consider procuring materials prior to the approval of the DCO by the Secretary of State. Finalisation of procurement requirements and the lead time to receiving materials can be as long as 18 months. Construction is dependent on the required pipeline lengths, and generally takes place during the summer months. In a one season construction campaign, typically between 40 – 60 km of pipeline can be constructed. Although this is dependent on pipeline diameter, the ground topography and the number of major crossing obstacles (e.g. railways, major rivers, motorways, etc.) that the pipeline must cross.

It may be possible to reduce some of the project timescale with regard to initial pipeline routing where existing pipeline easements can be utilised. However, the length of time to undertake the associated environmental surveys will remain broadly similar to those for a new pipeline route.

From the indicative schedule for a new pipeline shown in Figure 78, it can be seen that circa 5+ years is the minimum that should be allowed between starting the planning process and commissioning the pipeline. It should also be noted the any reinforcement of the electrical transmission system would be subject to similar DCO related planning constraints.

Figure 78 Indicative Planning Schedule for a New Pipeline



18. SUB REGIONAL PLAN

18.1. OVERALL METHODOLOGY

Generally, network conversion takes place from around 2030 up until 2045, at which point the distribution network is assumed to be fully converted. It has been assumed that the hydrogen distribution energy figures for 2050 are outliers as hydrogen consumption generally falls from that point.

The hydrogen distribution and gas distribution flow quantities from the whole system modelling have been proportioned, using the ratio of gas supplied by each NTS offtake as per current demand. The total number of non-dependent meters for each region (Wales or South West) is proportioned in line with the annual metered demand at each NTS offtake.

See an example for the application of this method in Table 15 for the ELE scenario.

Table 15. Proportion of Demand per Regional Offtake in 2050 - ELE

Offtake	% of Regional flow	Hydrogen Demand (TWh)	Number of Meters
Dowlais	42%	2.4	465,562
Dyffryn	18%	1.0	200,609
Gilwern	16%	0.9	175,464
Maelor	23%	1.3	256,388
Total	100%	5.6	1,098,023

In 2050 Wales there will be 1,098,023 non-dependent meters, which are split between offtakes in the same proportion as today. By proportioning the flow for a particular year versus 2045, the number of meters by offtake in that year can be calculated.

It is not general logical or practicable to convert all areas at the same time for the relatively small flows that exist at the beginning of the conversion process. Therefore, in the first years of conversion, the conversion process takes place in one area until either it reaches the maximum number of meters converting that year or the total number of meters for that offtake. Once the meters in an offtake location are fully converted then conversion moves on to the next area.

Conversion assumed to take place over 40 weeks per year (i.e. not physical conversion to take place over the winter months when peak gas usage may be required). This gives 200 weeks of conversion in a 5-year timeframe.

18.2. SUB REGIONAL CONCEPTUAL PLANS AND PULL OUTS

The Sub Regional Conceptual Plans (Sections 21-25) illustrate the uptake or conversion of non-industrial meters to hydrogen between 2020 and 2050.

To provide an indicative illustration of the conversion of meters to hydrogen, we took the assumption that 'named' HP pipes (e.g. Manordeilo - Llandovery) and nearby / dependent IP/MP/LP nodes would be converted together, and in sequence, starting with those most proximal to the respective injection point. We determined these injection points to be:

Gilwern: x,y

Dowlais: x,y

Dyffryn: x

Maelor: x

SW: x,y,z,…

The number of meters shown as converted in the sequencing illustrations is proportionate to the estimated heat demand anticipated to be delivered by H2, so provides an indication of the relative rate of conversion per 5-year time slice across the WWU network. The ETL software iteratively ‘adds’ HP pipes and proximal lower pressure meters until the relative threshold has been reached for that particular injection point. A sense check was then undertaken to ensure the illustrations showed an indicative illustration of the potential conversion of meters to H2 between 2020 and 2050, accounting for the complexity of the network and the large geographic spread of some of the HP pipelines.. In the absence of detailed network modelling, it illustrates an indicative practical pathway to the decarbonisation of the gas network.

19. CONCLUSIONS

19.1. SCOPE OF WORK

The present study work has taken an initial look at developing a Regional Decarbonisation Pathway for Wales and the South West. It sets out a credible gas network decarbonisation strategy in consideration of:

- Future energy demand as defined by energy systems modelling scenarios, which optimise whole system costs based on the input assumptions assigned for each scenario, whilst meeting 2050 net-zero emission targets and broad energy supply and demand balance requirements
- Current UK energy strategy and specific plans for UK wide gas network development, particularly in regard to hydrogen supply, transmission and storage.
- Practical considerations in terms of regional hydrogen production capacity, network capacity, network integrity and gas network reliability to meet security of supply commitments.
- Under some scenarios hydrogen is introduced into the distribution from the early 2030s. If new infrastructure is required and given the length of time that planning approval can take, it would be prudent to consider starting conceptual design activities in early 2024.

This work constitutes the first step in what will be a structured and managed programme of works which will move from a focus on studies to implementation works over time. This programme of works will be more explicitly drawn out in the work presented in the Regional Decarbonisation Pathways plans.

19.2. ASSUMPTIONS AND UNCERTAINTIES

A number of assumptions used in the energy systems modelling aspect of the delivered scope of work have been discussed and agreed in consideration of any evidence available from existing work to date and from key stakeholder feedback. It is acknowledged that predicting the precise decarbonisation options and the magnitude of each in the overall future energy consumption framework is a challenge. However, it is expected that the potential envelope of possibilities can be defined to some degree of confidence by the extreme scenarios of high electrification and high hydrogen as per Future Energy Scenarios approaches. It was therefore decided not to investigate the extreme extents of either electrification or hydrogen network scenarios in the present study since the probability of such scenarios being realised is low. However, if in future it is identified that the UK is demonstrably on a trajectory to realise one of these extreme scenarios, then this study work should be updated at that time if required. The analysis performed has identified that the decisions made by key industrial stakeholders (such as power plant operators) if implemented as a block, could drive outcomes towards one extreme or the other. I.e. A median outcome is not necessarily also a more likely future outcome.

UK decarbonisation strategy, particularly on hydrogen, is based around the development of hydrogen production and baseload demand driven by decarbonisation of major emitters at Industrial Clusters. The key emitters (power generation and iron and steel industry for the case of Wales) are likely to have a significant impact on the initial net zero pathway solutions which are established in each region. It is recognised that at this early stage there is considerable uncertainty in terms of how and when individual industries and specific sites will decide to decarbonise and therefore the energy systems infrastructure which will be retained, extended and/or developed to support this activity.

While assessments including energy systems modelling and network conversion plans can be developed based on the study assumptions, the present work has a sizeable degree of uncertainty attached. This is not unusual at this early optioneering and feasibility stage of an engineering programme, or enterprise. Uncertainty in the definition of decarbonisation pathways may also come from the fact that gas and electricity network operators would need to react to policy driven developments undertaken by others, at a point in time when this policy is deployed.

19.3.STUDY METHODOLOGY

ESC's ESME modelling provides a credible perspective on future hydrogen demand in WWU's area of operations across Wales and the South West.

However, in practice the future could potentially look very different, dependent upon the strategic designs made by a few key stakeholders. UK Government policy, such as the UK's Industrial Cluster Mission, is likely to initially drive hydrogen production and demand for industrial emissions reduction.

North Wales & South West are likely to take the lead from the infrastructure projects being developed in the North West and South Wales (Merseyside and South Wales Industrial Clusters).

Power producers are a key gas consumer. How they decarbonise operations will significantly influence the future regional hydrogen demand.

Similarly the decarbonisation decisions made by the four main non-power emitters: Tata Steel Port Talbot, Valero Pembroke Refinery, and the cement works at Padeswood and Aberthaw, are also likely to have a significant influence on the decarbonisation solutions which are implemented overall in their regional location and also when they are implemented.

If there are no large industrial hydrogen related projects, then any hydrogen roll-out is less certain and would be expected to take longer.

With the technical and practical gas and electricity system constraints likely to have an increased impact on selected solutions.

SECTION D – SUB-REGIONAL ANALYSIS

SECTION D - SUB-REGIONAL ANALYSIS

NORTH WALES PULL OUT*

* This sub-regional analysis should be read in conjunction with Parts A, B and C of the report

20. SUB-REGIONAL NETWORK ANALYSIS – NORTH WALES

This sub-section of the report provides further interpretation for the sub-region of North Wales of the whole systems modelling undertaken by the Energy Systems Catapult (ESC) in Sections 6 and 7 and the engineering analysis undertaken by Costain in Sections 10 to 16 of the main report.

The North Wales analysis is structured in a similar way to the earlier sections of the report, with the implications of ESC's modelling set out in a Strategic Plan sub-section (see section 20.3) and the Costain engineering analysis set out in a Conceptual Plan section (see section 20.5). In advance of both these sub-sections, an overview of the key features of North Wales is provided (see Section 20.1).

20.1. OVERVIEW OF NORTH WALES

The North Wales sub region is that part of WWU's North Wales license area (Figure 79) served by the northern branch of the HP network originating at the Maelor National Transmission System (NTS) offtake at in the County Borough of Wrexham. Along with the northern part of this borough, the sub region includes Denbighshire, Conwy, and the Isle of Anglesey in their entirety, almost all of Flintshire, the majority of Gwynedd, and the northern tip of Powys.

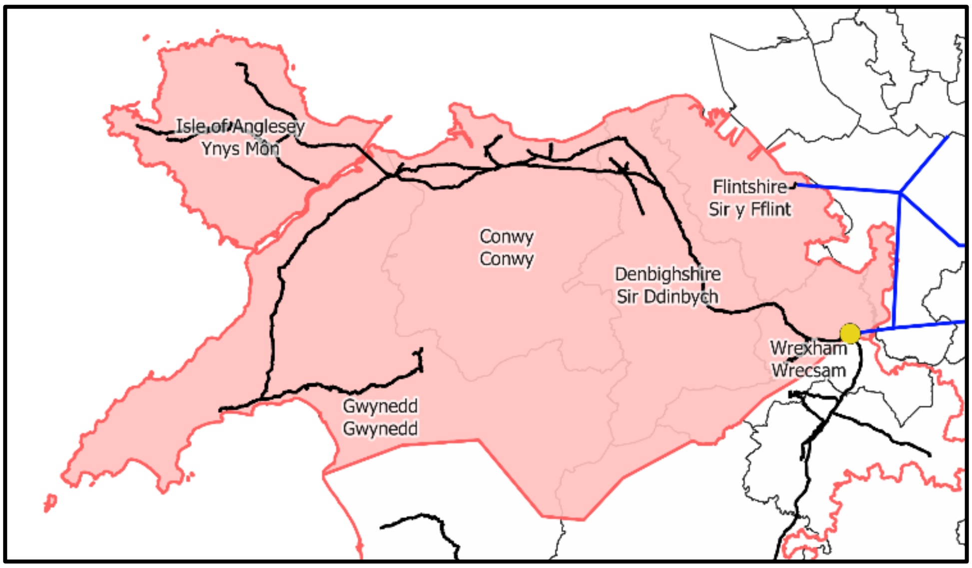


Figure 79: The North Wales sub-region at present. The black lines show WWU's high-pressure (HP) network. The approximate route of the national transmission system (NTS) gas pipelines is shown in blue. Yellow circles represent 'offtakes' where gas flows from the NTS to the HP network.

Beyond the offtake at Maelor and a small section proving supply to Flintshire, there is no NTS in North Wales. The local gas distribution network infrastructure serves all gas demand connections mixed between rural areas in the south of the region with more urban areas in Wrexham and the north. The high-pressure network configuration is mainly linear, connecting the network to the single offtake in the East. Urban areas on the North Coast have a level of inter-connection across all the pressure tiers.

20.2. KEY INSIGHTS

Analysis undertaken in the Regional Decarbonisation Pathways project has developed a number of key insights for the development of a Net Zero energy system in North Wales.

ESC's Strategic Plan (detailed in sections 20.3 to 20.4) found that:

- A high proportion of domestic and business gas network connections are retained under the scenarios analysed, driven by the significant uptake of hybrid heating systems and standalone hydrogen boilers. The way the gas grid is used and the volume of hydrogen flowing through it is likely to be very different.
- Disconnections from the mains gas for heating are driven by switching to district heating networks. District heat is deployed in the most densely built-up areas where it is most economical, and so disconnections from mains gas are concentrated in such areas, too.
- Across all three scenarios, the quantity of network infrastructure required to serve the retained natural gas and new hydrogen demands in South Wales are the same, though the volume they will supply varies. There is extensive opportunity to use existing infrastructure to serve these demands: both the low and medium pressure networks indicate a high proportion of repurposing.

Costain's Conceptual Plan (detailed in section 20.5) found that:

- North Wales is likely to be a net importer of hydrogen in early years, but could become a net exporter with the development of green hydrogen. Opportunities for nuclear power and hydrogen cogeneration in North Wales are concentrated around Wylfa.
- There are a small number of larger emitters dominate which are generally located in the Deeside / Connah's Quay area. The decisions taken by the major emitters to decarbonise their emissions will have a significant impact on the energy transition solutions deployed in the region, and the timing of the infrastructure developments required.

20.3. STRATEGIC PLAN ANALYSIS (WHOLE SYSTEM MODELLING)

ESC's Strategic Plan analysis has been developed to provide insights into the possible future role of the gas network in North Wales. It uses, as its basis, three whole system energy scenarios developed in collaboration with Wales and West Utilities and Costain, to explore different futures for hydrogen use in the South-West of England and Wales. These three UK-wide, whole energy system scenarios are described in Section 5.5 of the main report and are:

- Consistent with the UK's 2050 Net Zero and interim, statutory carbon targets.
- Identify three levels of hydrogen use for the South-West of England as part of the wider UK energy system.

This section should be read in conjunction with earlier parts of this document, to gain a full understanding for the context for the scenarios and the pathway for the broader whole energy system in Wales, within the wider context of the rest-of the UK energy transition. These three scenarios provide the basis for a strong role for hydrogen. Other scenarios will see less use and some more.

This is the first-time whole system energy modelling has been linked to sub-regional strategic network modelling analysis, to start to understand the potential shape and nature of the Wales and West Utilities (WWU) gas grid in 2050. This is network analysis and insights, based upon whole system modelling and there will be practicalities and engineering constraints faced by hydrogen network conversion. These considerations are further assessed in the sub-regional Conceptual Plans produced by Costain in section 20.5, below.

This analysis does not replace the need for detailed network modelling and engineering-based feasibility and design but are intended as the basis for analysis and discussion.

20.4. STRATEGIC PLAN INSIGHTS

The key insights for gas and hydrogen networks in North Wales, identified through this Strategic Plan analysis are:

- A high proportion of domestic and business gas network connections are retained in the scenarios, driven by the significant uptake of hybrid heating systems (i.e., heat pumps providing baseload heat and hydrogen boilers providing peaking) and standalone hydrogen boilers. Despite this similarity, the proportion of these systems which are hybrid rather than standalone boilers, is significantly higher in the ELE scenario than in BAL and HYD, and the annual hydrogen consumption is correspondingly lower, as a greater proportion of baseline heat demand is met by electricity.
- Disconnections from the mains gas for heating are driven by switching to district heating networks. District heat is deployed in the most densely built-up areas where it is most economical, and so disconnections from mains gas are concentrated in such areas, too. In BAL, the analysis suggests that in the conurbations around Rhyl and Prestatyn, Llandudno and Colwyn Bay, and Connah's Quay nearly 85% of the dwellings will be on district heat networks by 2050.
- The similarity in the number of retained domestic and business connections and industrial fuel switching patterns translates to almost identical requirements for changes to the network infrastructure by 2050 (lengths of new/repurposed pipe etc.) in all three scenarios despite the substantial variation in the amount of hydrogen consumed for heat. While

uncertainty around the optimality the level of hybrid heating systems deployment in the modelling means that these interventions cannot be interpreted as a 'low-regret' option, it does illustrate how systems with quite different amounts of hydrogen consumption could require similar levels of investment to support the transition from gas.

Nuclear power/hydrogen cogeneration features in the regional modelling for Wales in all three scenarios, and in all three this is concentrated at the Wylfa site in North Wales. Connah's Quay is one of the two indicative sites to which electrolytic hydrogen production capacity has been allocated in Wales, on the basis that grid connected electrolysis near here could complement offshore wind generation. Only the HYD and BAL scenarios feature electrolytic hydrogen production, however.

- Each scenario explored the quantity of network infrastructure required to serve the retained natural gas and new hydrogen demands. The changes needed for North Wales are the same for all three scenarios. A potential opportunity to re-purpose existing natural pipe assets for service in a hydrogen network has been identified. Both the low and medium pressure networks indicate a high proportion of repurposing at 97% (2,277km) and 96% (154km) respectively of existing pipes.

  In the intermediate and high pressure tiers the opportunity is 80% (368km) and 24% (88km) of existing pipelines respectively. This insight is indicative and should be considered in the context of this modelling. A complete view of the feasibility of repurposing these assets will become available once industry technical, safety and network transition studies are completed.

20.4.1. SCENARIO ANALYSIS

The three whole system scenarios used as the basis of the modelling are the High Electrification (ELE), Balanced (BAL) and High Hydrogen (HYD) which are distinguished by several different assumptions summarised in section 6.1.2. The major distinguishing features of the scenarios (i.e., the results of the modelling) are their relative use of the type of heating system present in 2050:

- The ELE scenario sees a prevalence of electrical systems (heat pumps, electric resistive heaters) to provide heat in residential and non-domestic buildings, and hydrogen can operate in peak demand periods but with a limited load factor. This scenario favours hybrid electric-hydrogen[14] systems as a result.
- The BAL scenario, the amount of heat supplied by heat pumps is restricted and hydrogen and electrical systems are set to be equal, reflecting a world where no strong policy is supporting the deployment of heat pumps.
- The HYD scenario assumes that most heat is supplied by hydrogen-based heating systems (hybrid electric-hydrogen systems, hydrogen boilers) and policy supports deployment of hydrogen technology.

Further detail is provided in section 5.5 of the main report.

20.4.1.1. 2050 GASEOUS FUEL SUPPLY, PRODUCTION, AND TRANSMISSION

Across the three scenarios explored in this project, both hydrogen and gas have a role within a Net Zero energy system in North Wales in 2050. The present natural gas NTS does not extend beyond

[14] Hybrid systems use heat pumps to provide baseload heating and hydrogen boilers to provide peaking.

Maelor into the sub region (Figure 79). Supply from this NTS offtake is assumed to be available under all scenarios to the extent that it will meet retained regional natural gas demands in 2050. Given the low quantity of natural gas demand in North Wales, this could be uneconomical for distribution or transmission networks. Any change to this assumption would have a resultant impact on both the retained natural gas network and transition options to a hydrogen network. Further economic analysis assessing the value of demand and costs of network retention is required.

Hydrogen production by electrolysers using nuclear power 'Nuclear Power Hydrogen Cogen' (described in section 6.2.2) is located exclusively in North Wales and present in all three scenarios. Its location is assumed to be in the north-west of the sub region, this has been speculatively located based on the use of facilities in the vicinity of existing nuclear sites. Providing this study with an indication of how the technology could be deployed and interact with hydrogen networks. Further economic and technical studies are required to understand the feasibility of this technology.

Hydrogen production in the opposite side of North Wales to the NTS offtake could provide a west to east supply of hydrogen during transition of the natural gas network. Potentially giving WWU more flexibility for the transition and reducing the quantity of network required for natural gas service during transition. Further engineering analysis is required to understand the scale of opportunity. Additional hydrogen production by electrolysis is present in the BAL and HYD scenarios. The indicative locations for electrolysers were chosen on the assumption that grid-connected electrolysis near connections to offshore wind farms could add value to the system by helping to manage the variable generation at these sites. In North Wales, a site on the north east coast was selected. No hydrogen production in North Wales requires a natural gas supply, limiting the quantity of retained natural gas network required in 2050.

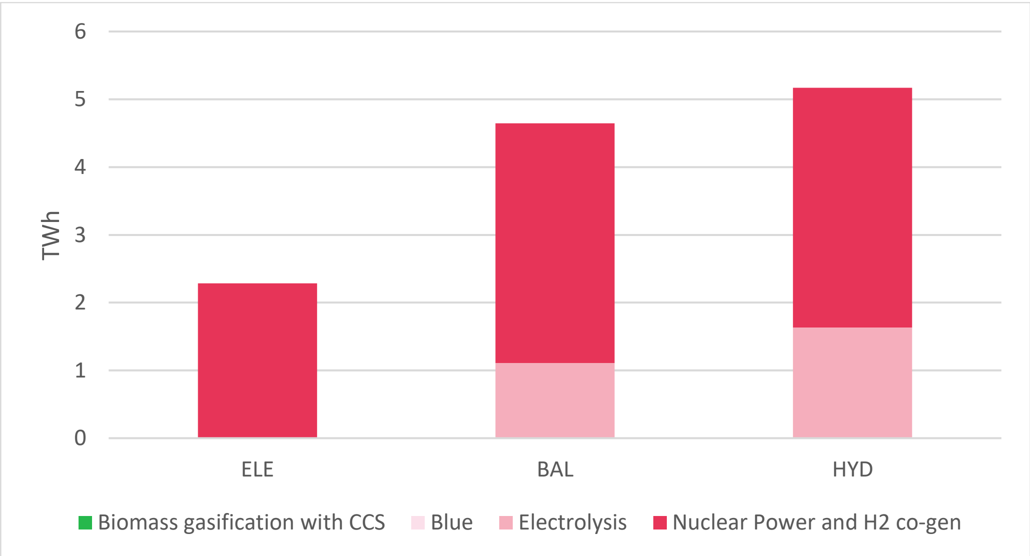


Figure 80: Annual hydrogen production in North Wales in 2050 by scenario (TWh)

As shown in Figure 80, the present national transmission system (NTS) for natural gas does not extend far into North Wales. So, unless a hydrogen NTS is extended beyond the current natural gas NTS into North Wales, all hydrogen consumed in the sub region in 2050 would be supplied by a hydrogen offtake at this point or the production technologies mentioned above.

20.4.1.2. GASEOUS FUEL CONSUMPTION

Industrial

North Wales contains seven large industrial sites in three of the four of the industrial sectors considered to have ongoing natural gas demand in 2050: chemicals, paper mills, and iron, steel, and non-ferrous metals. These are assumed to all remain in 2050 in all scenarios, however their continued operation will ultimately be subject to a range of other economic factors, including the future of the energy system. All seven industrial sites are gathered at the north-east border of North Wales, close to the LTS offtake located close to Wrexham which supplies their natural gas.

It is assumed that all sites in other industrial sectors can switch to hydrogen by 2050, supporting wider network transition. Practically the switchover of industrial demands during network transition is likely to be complex, requiring consideration of both local network and stakeholder factors. Additional commercial and engineering analysis is required to identify interdependencies and understand how these can be managed to optimise network transition. Further details of how industrial demand has been modelled is provided in section 4.

Non-industrial

For the scenarios explored, domestic and commercial gas demand for space heating and hot water is replaced by a combination of hydrogen, electricity, and heat network-based heating solutions. Gas boilers are displaced by hydrogen boilers, hybrid hydrogen heat pumps, heat interface units for heat networks and electric resistive heating. The combination of these is an output of the regional strategic modelling (see section 6.2.7) and depends somewhat on the underlying assumptions informing each scenario.

Typically, in the ELE scenario, the bulk of the heat is supplied by electric heating systems, and hydrogen boilers are limited to backup operation at peak times. the presence of district heating is conditioned by the density type of buildings, making it more economical in denser areas where the transportation losses are reduced. The adoption of heat network is the main driver to disconnection from the gas network in 2050.

From a whole system perspective, hybrid boilers are valuable, reducing the capacity and associated cost of heat pumps whilst mitigating the expense of meeting high electricity peak demands and utilising existing infrastructure assets and low-cost storage. However, further work is required to understand the impact of network maintenance costs and the transitional capital costs to realise least cost system designs.

Notable differences identified between the scenarios include a much higher proportion of total heat production throughout the year due to Hydrogen boilers in HYD than in BAL, and in BAL than in ELE. Based on this analysis, switching from mains gas to district heating is the only driver of disconnection of non-industrial meters considered across all three scenarios.

20.4.1.3. CHANGES TO THE GASEOUS DISTRIBUTION NETWORKS

Non-industrial connections and low-pressure networks

Within North Wales, all three scenarios tested suggest that 2-3% of domestic and commercial connections are removed and the remaining number switch from natural gas to hydrogen. Between 2% and 3% of the Low Pressure (LP) gas network is decommissioned.. Where connections switch away from a hydrogen supply, between 2-3% of homes across all three scenarios, have their heating provided through district heating in 2050 – see section 7 for more detail on the method.

These modelling outputs suggests that large volumes of connections and LP network are retained across the scenarios, care is advised when interpreting this insight. The modelling method used is based on a breakdown of a least cost whole energy system for the UK to a regional level such as North Wales. Resulting in retention of parts of the gaseous network which may be uneconomical in some scenarios. Further technical and economic analysis is required to obtain additional understanding of the interaction between local, regional, and national networks to enable cost optimal system design at each level. The scenarios here have indicated that where volumes of hydrogen reach low levels there could be a requirement to consider economic optimisation by assessment of further options between different levels of geographic granularity.

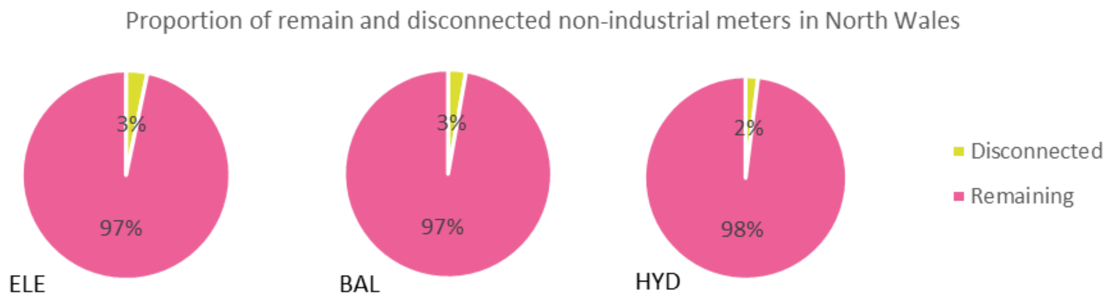


Figure 81 - Non-industrial disconnection and remaining meters in North Wales (total number of meters: 226895)

Service pipes link the LP network to individual properties. An H21 project report[15] suggested a proportion of these could require replacement due to the higher volumetric flows of hydrogen required to supply a given amount of energy. There is significant uncertainty around this issue, and it has been suggested that many of these works could be avoided by various network level solutions, however this could have significant implications for customers. An estimated range of service pipe replacements for North Wales is 137,000 to 139,000 across all three scenarios.

Medium, intermediate and high-pressure networks

Each scenario explored has an associated 'Bill of Quantities', indicating the quantity of infrastructure needed, summarised in Figure 82. This is the same for all three scenarios in North Wales, discussed in section 4. Values are given as a percentage of the length of currently existing network for each respective pressure tiers – these are of 373km for the HP network, 456km for the IP network, and 160km of MP network.

[15] NIA 275 H21 – Hydrogen Ready Services (https://h21.green/app/uploads/2021/02/NIA-275-H21-Hydrogen-Ready-Services-Final-Version.pdf) [Accessed 24/03/2022)

In modelling the transition of networks from the network as it is today to one indicative of that required to serve the 2050 scenarios, the method re-purposes as much of the existing natural gas network for hydrogen service as possible. This was done whilst considering the need to maintain a natural gas supply through the transition and practical switching constraints of connections dependent on a natural gas supply to one receiving hydrogen. The result is an increased quantity of repurposing that is considered generous and reduced amount of new hydrogen. Transition of gas networks is recognised as a highly complex process and further analysis is required to fully understand the influencing factors to inform decisions. The detail of the modelling logic is provided in section 7.

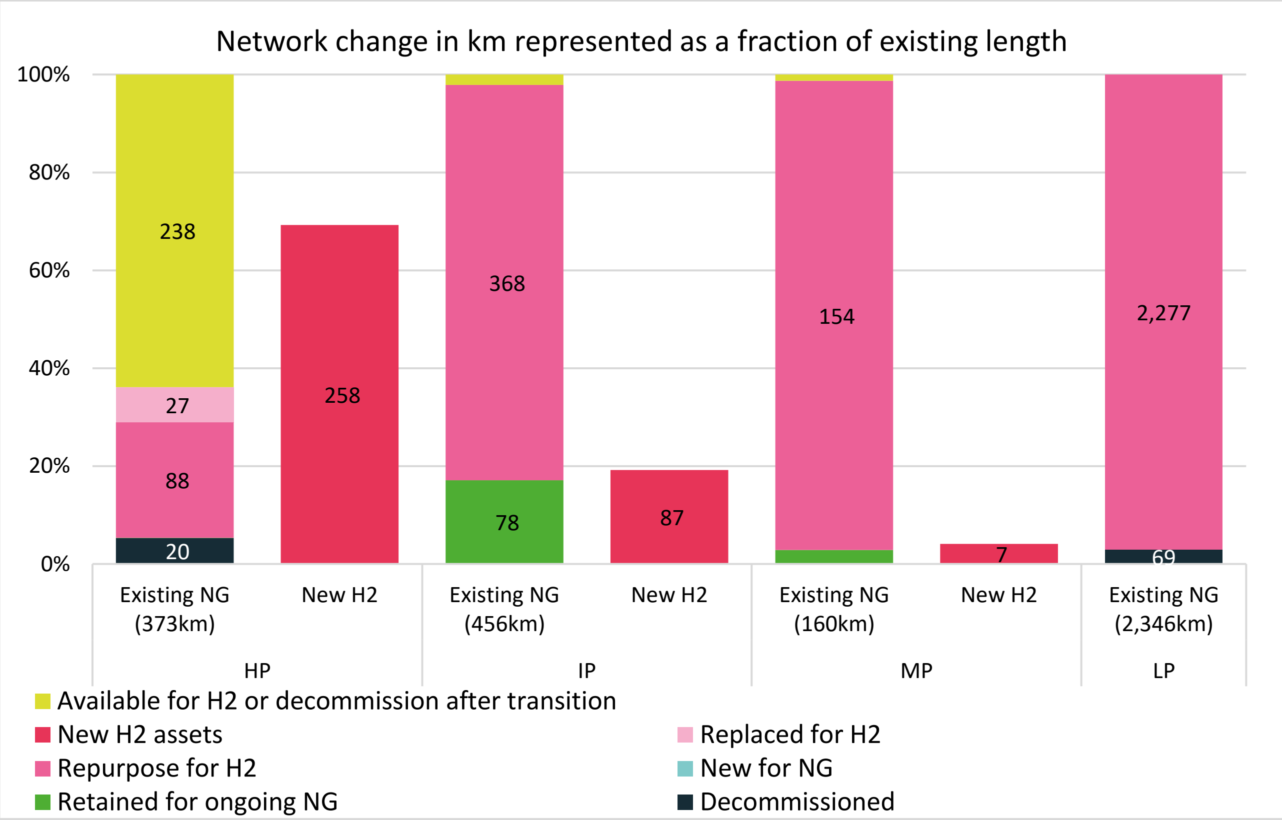


Figure 82: Network changes as a percentage of existing pressure tier length

Medium Pressure

Less than 3% of the length of the current MP network remains on natural gas in 2050. The assets used for this purpose correspond to the last few tens of kilometers between higher pressure tier pipelines, and industrial demand sites. This figure is very low in North Wales because most of these remaining demand sites are directly connected to the IP network. The relatively evenly distribution of demand along the network in addition to a good interconnection within the network results in very low transition constraints at the MP and IP levels but appear the HP level (see below).

As a result, 96% of existing MP pipe could be repurposed for hydrogen service, and new MP pipe for hydrogen service represent around 4%.

Intermediate Pressure

Similar to the MP network, the IP network in North Wales is not constrained by transition needs – only less than a few percent. However as mentioned above, most of the demand is supplied directly at intermediate pressure, resulting in around 17% of the network length that would be retained for ongoing natural gas demand in 2050. These are indicative figures, which could be refined by, more detailed flow analyses.

The remaining 81% of the IP network could be directly repurposed to hydrogen service, corresponding to the need for entirely new hydrogen assets representing around 17% of the existing network length.

***High* Pressure**

There are no retained HP assets for ongoing natural gas demand in 2050: all of the remaining demand is around industrial sites in the north-east of the sub-region and is entirely supplied by IP and MP pipes.

As mentioned above, most of the transitional constraints (high number of connections dependent on a single stretch of pipes, (see section 7) are emerging at the HP level, and close to 65% of the network length would be “available for hydrogen or decommissioned after transition is complete”.

Around 12% of existing hydrogen assets are vintage and would either need to be replaced to serve hydrogen demand (7%) or be decommissioned (5%).

The remaining 24% of the existing network could be repurposed for hydrogen supply by 2050, which means that the need for entirely new hydrogen pipes would represent almost 70% of the existing network length.

20.5. CONCEPTUAL PLAN

The Conceptual Sub Regional Pull Outs are based on engineering analysis which considers the implications of the scenarios for natural gas and hydrogen infrastructure. This provides a basis to understand the decisions which are required around investment in network infrastructure to support decarbonisation and, provide an indicative illustration of the uptake of conversion of Domestic and Commercial meters to hydrogen between 2020 and 2050, across the three scenarios.

20.5.1. KEY INSIGHTS

- Given the proximity of HyNet, to North Wales it is likely to be a net importer of hydrogen in the first years. However, in later years there is a potential for green hydrogen to produced and this could lead to North Wales becoming a net exporter of hydrogen to both the North West of England and Mid Wales. The relatively close proximity of the North Wales supply area to the gas storage facilities in Cheshire will allow this local supply area to have access to these facilities for seasonal and diurnal storage requirements.
- Potential to Repurpose: The majority of the LTS system in North Wales (Figure 55) was constructed from pipe material strength grade of X52 and below. These pipe materials are suited to the transportation of hydrogen. There are relatively few sections of the network in North Wales which are over fifty years old. Some of the older pipelines may also have been used for Towns Gas service, which can also suffer from further degradation due to the effect of hydrogen on the pipe wall. Where these pipelines are to be replaced then it is recommended that they are replaced with pipelines suitably sized and with a pipe material grade which suitable for hydrogen service.
- For all three scenarios in Wales approximately 97-98% of the Domestic and Commercial gas meters are estimated to be retained in 2050.

Table 16. North Wales Meters Converted per 5 Year Cycle

North Wales	Number of Meters Converted per 5 Year Cycle						
	2020	2025	2030	2035	2040	2045	2050
High Electrification	0	0	0	789	236	0	0
Balanced	0	0	271	457	297	0	0
High Hydrogen	0	0	100	559	330	46	0

It can be seen from Table 16 that under the Balanced and High Hydrogen scenarios conversion starts circa 2030, while the High Electrification scenario starts approximately 5 years later. The workforce size requirements to undertake conversion will be similar under all scenarios. Circa 2035 is the peak year for conversion.

- Due in part to the high retention of the Domestic and Commercial customer base, all three scenarios in North Wales will require similar levels of new pipeline infrastructure to enable conversion to hydrogen. In total approximately 115.9 km of new high pressure LTS hydrogen pipeline would be required in North Wales by 2045. Also, they may a requirement for short sections of additional new natural gas pipeline to provide cross connections within the existing network during conversion.

Table 17. North Wales KM of New Hydrogen Pipeline per 5 Year Cycle

North Wales	KM of New Hydrogen Pipeline per 5 Year Cycle						
	2020	2025	2030	2035	2040	2045	2050
High Electrification Scenario	0	0	108.6	0	7.3	0	0
Balanced & High Hydrogen Scenarios	0	0	108.6	0	7.3	0	0

Table 17 details an indicative level of the length of new hydrogen pipeline required in a particular 5 year cycle

20.5.2. BALANCED (BAL)

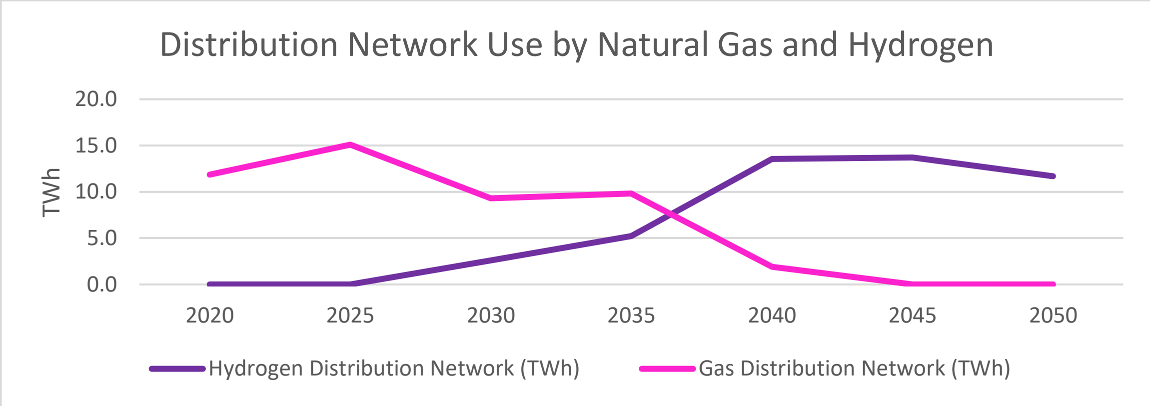
Table 18 shows the forecast hydrogen production and, distribution network consumption of natural gas and hydrogen for the Balanced (BAL) WWU scenario modelled in ESME in Wales. It can be seen that hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Initially hydrogen is supplied to industrial users and starts to be supplied to the distribution system from 2030 with the system supplying the maximum predicted hydrogen demand in 2045. Before consumption drops away towards 2050. Conversion of the Distribution Network is completed shortly after 2040.

Table 18. BAL Hydrogen Production Capacity and Gas Distribution Consumption

	Year						
	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.8	1.2	5.9	11.3	47.8	42.2	33.4
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	2.6	5.2	13.5	13.7	11.7
Natural Gas Consumption from Distribution Network (TWh)	11.9	15.1	9.3	9.8	1.9	0.0	0.0

Figure 83 BAL Wales Distribution Network Use by Natural Gas and Hydrogen



As detailed in Section 10 there are a small number of larger emitters dominate which are generally located in the Deeside / Connah's quay area. The decisions taken by the major emitters to decarbonise their emissions will have a significant impact on the energy transition solutions deployed in the region. Figure 84 shows the NAEI Sector and emission tonnage for the major emitters of carbon dioxide in North Wales.

Figure 84 North Wales - NAEI Large Emitters by Sector and Emissions Tonnage

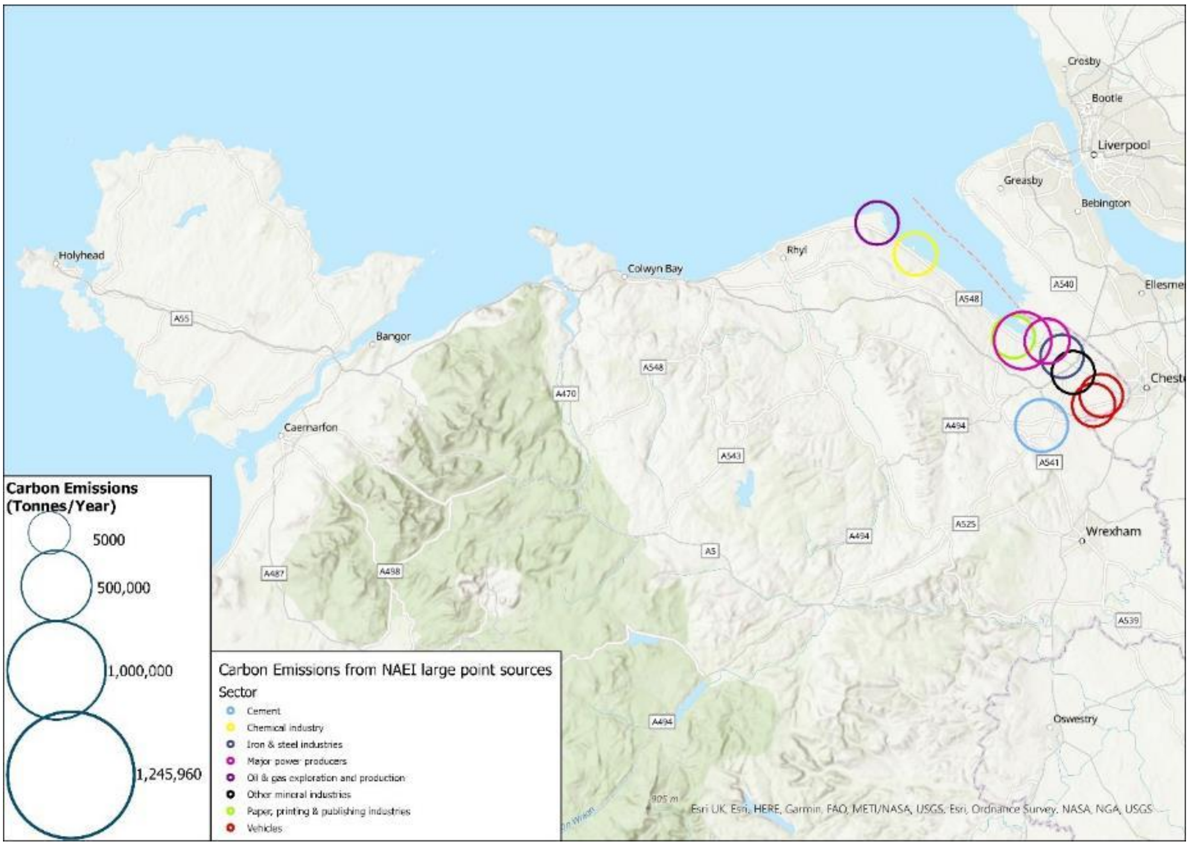


Table 19 shows the forecast number of North Wales meter points that require converting from natural gas and hydrogen on the distribution network for the Balanced (BAL) scenario.

Table 19. BAL North Wales Meters Converted per 5 Year Cycle

	Year						
	2020	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Total - Maelor Coast	0	0	54,291	91,389	59,483	0	0
Meters Converting per Week (40 Wks/Year)	0	0	271	457	297	0	0

It should be noted that the number of meters requiring conversion each week is based on the assumption that conversion will take place outside the peak winter demand supply period i.e. over 40 weeks per year (March to November).

Figure 85 BAL Scenario 2030 – Domestic and Commercial Meters

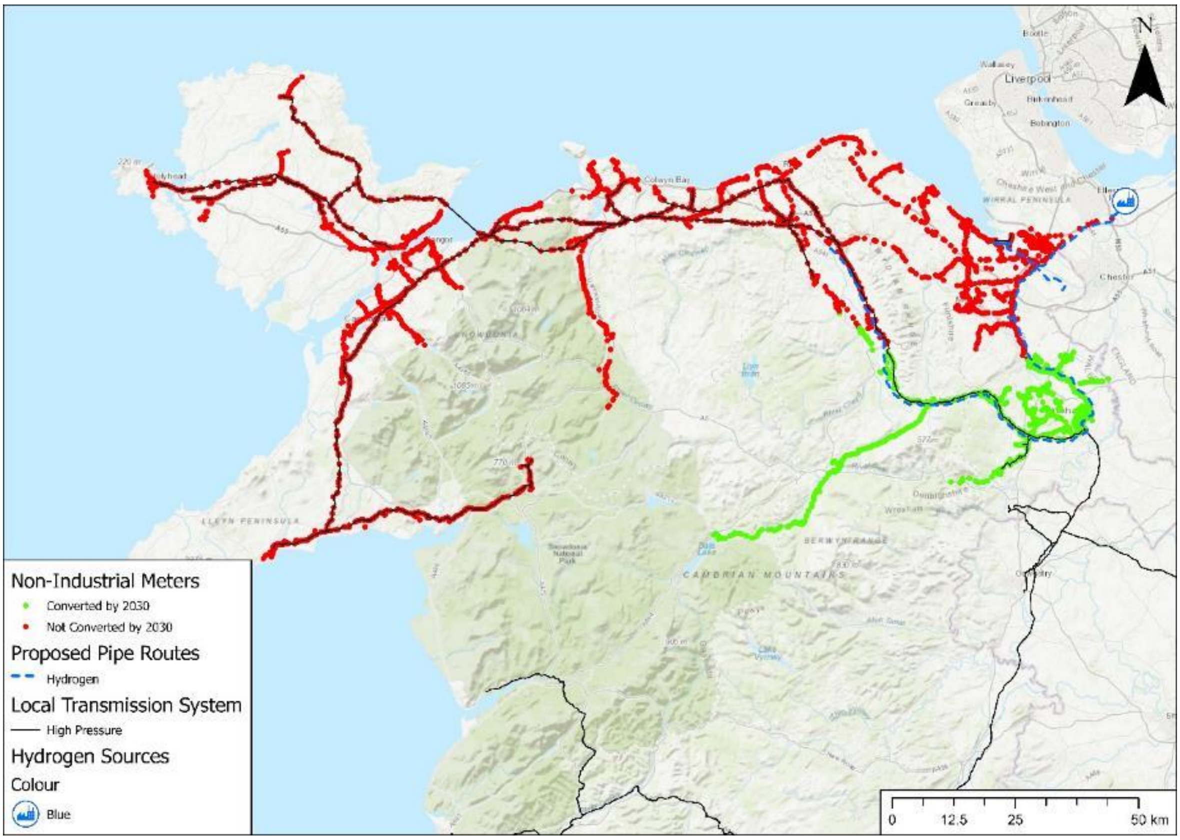


Figure 86 BAL Scenario 2035 – Domestic and Commercial Meters

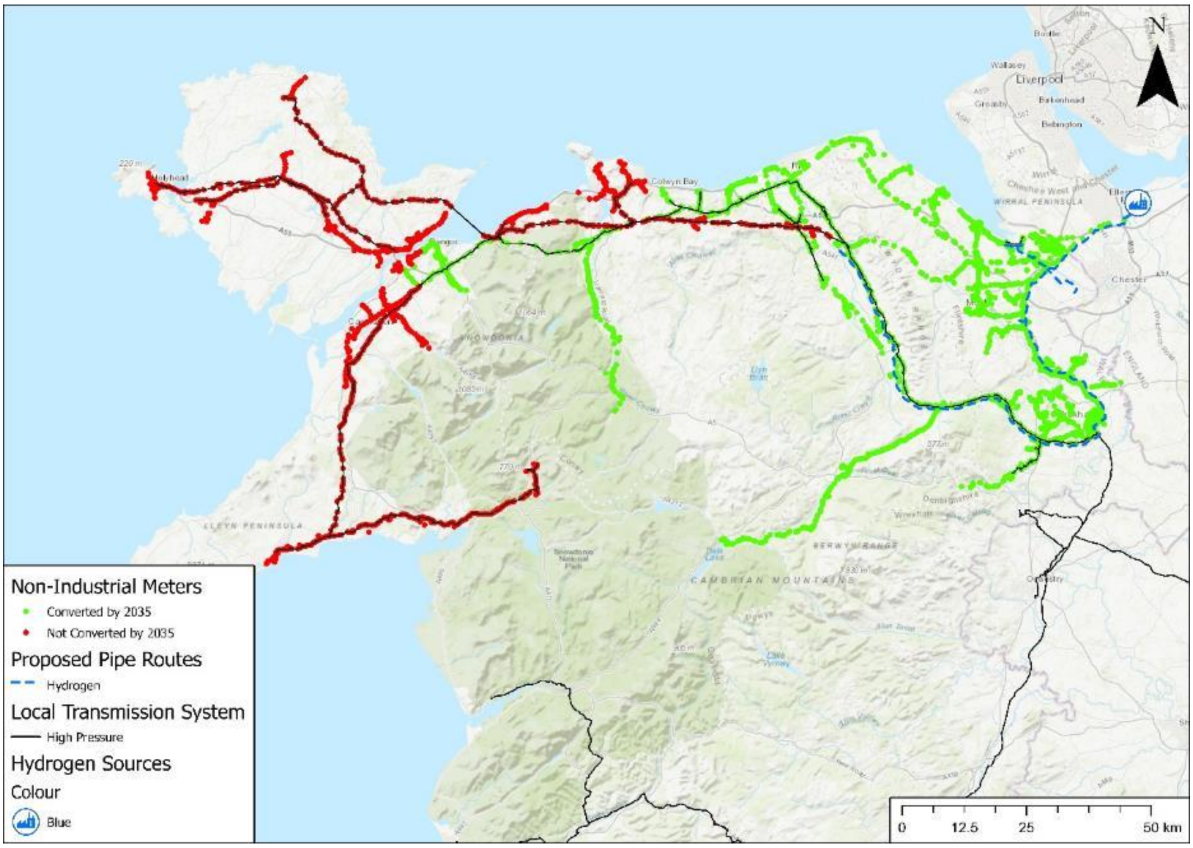
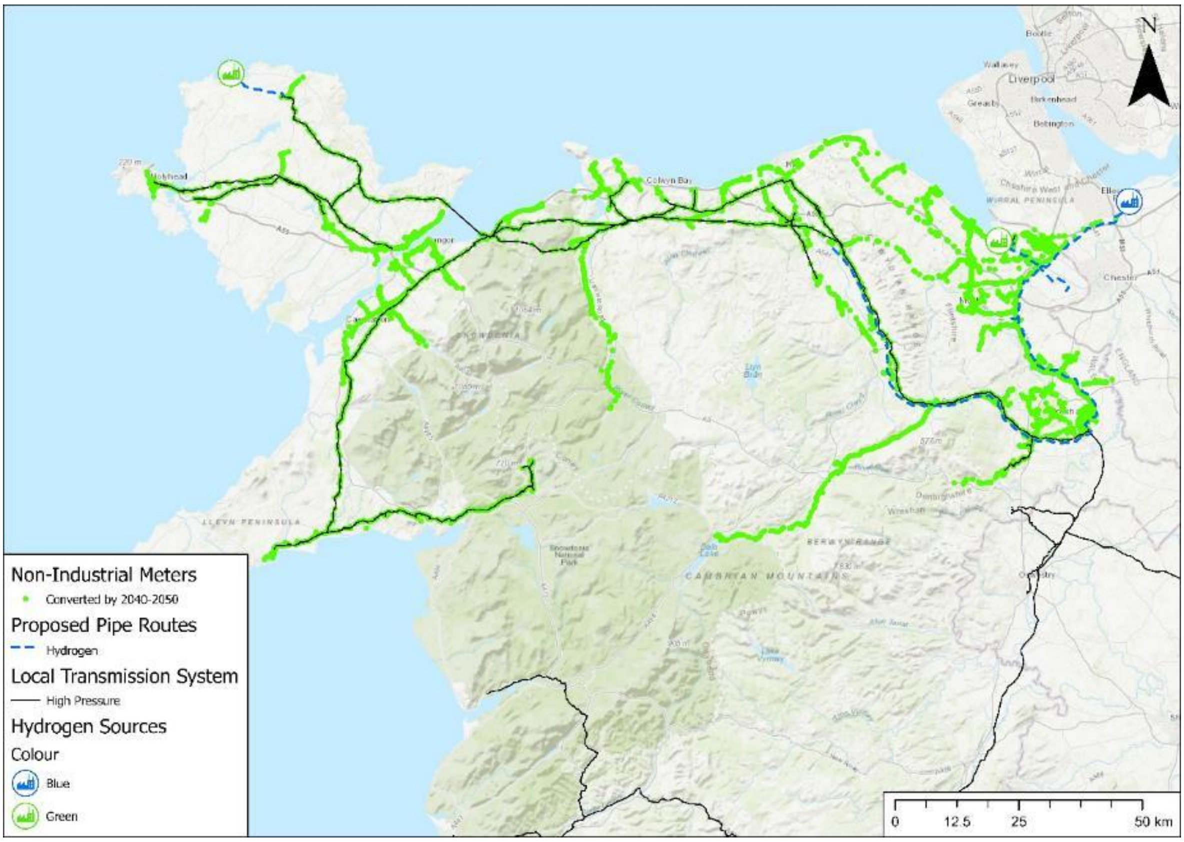


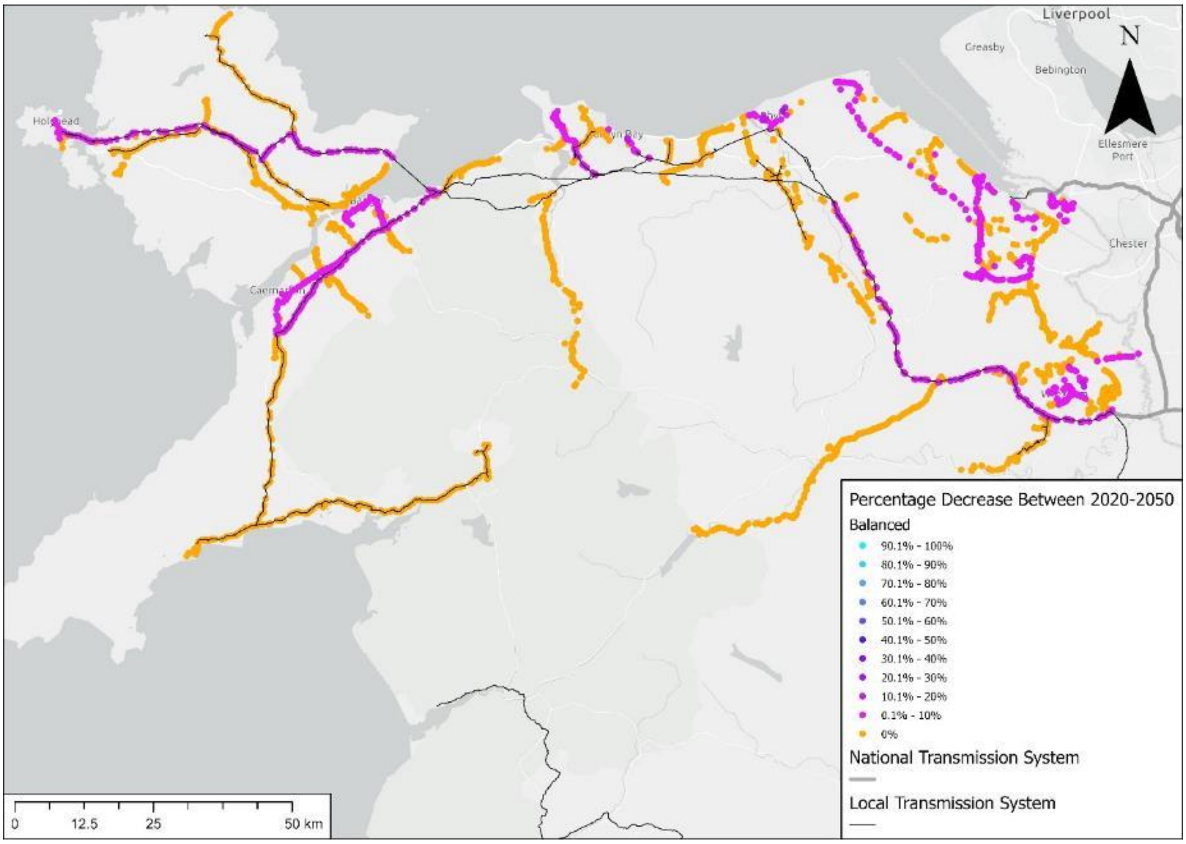
Figure 87 BAL Scenario 2040 – 2050 – Domestic and Commercial Meters



Under the BAL scenario there will be an approximate 5% reduction in the number of non dependent meters.

Figure 88 details the areas where there is predicted to be a fall in the number of customers on the gas system.

Figure 88 BAL Scenario 2050 - Change in the Domestic and Commercial Meters



20.5.3. COMPARISON OF THE THREE SCENARIOS

According to the ESME Whole System Overview (Section 6.2), for all three scenarios hydrogen production ramps up and peaks in similar timescales. Production of hydrogen and hydrogen consumption from the distribution network are broadly similar for High hydrogen (113% of balanced). However, in the High electrification case production of hydrogen and hydrogen consumption from the distribution network is lower than the Balanced scenario (78% of Balanced). As the number of domestic meters is broadly the same across all three scenarios, this would indicate that individual consumption is the primary variable rather than the number of supply points. As can be seen from Figure 88, there are slight falls in the number of domestic meters in the major conurbations and this is broadly reflected across all three scenarios with a slightly greater reduction in the numbers of meters in the High Electrification scenario.

The quantity of new pipeline required will be similar across all three scenarios, due in part to the requirements for the system to be able to supply peak demand. Due to the availability of offshore wind there is potential to potentially produce more hydrogen under the high electrification scenario.

Details of the Conceptual Plan analysis of Electrification and High Hydrogen scenarios can be found in Section E.

SECTION D - SUB-REGIONAL ANALYSIS

MID WALES PULL OUT*

* This sub-regional analysis should be read in conjunction with Parts A, B and C of the report

21. SUB-REGIONAL NETWORK ANALYSIS – MID WALES

This sub-section of the report provides further interpretation for the sub-region of Mid-Wales of the whole systems modelling undertaken by the Energy Systems Catapult (ESC's) in Sections 6 and 7 and the engineering analysis undertaken by Costain in Sections 10 to 16 of the main report.

The Mid-Wales analysis is structured in a similar way to the earlier sections of the report, with the implications of ESC's modelling set out in a Strategic Plan sub-section (see section 21.3) and the Costain engineering analysis set out in a Conceptual Plan section (see section 21.5). In advance of both these sub-sections, an overview of the key features of North Wales is provided (see Section 21.1).

21.1. OVERVIEW OF MID WALES

The Mid Wales sub-region is the part of WWU's Mid Wales license area (Figure 89) served by the southern branch of the High Pressure (HP) network originating at the Maelor National Transmission System (NTS) offtake in the County Borough of Wrexham. Along with the southern part of this borough, it includes large parts of Ceredigion, Powys, and Gwynedd, and portions of Shropshire.

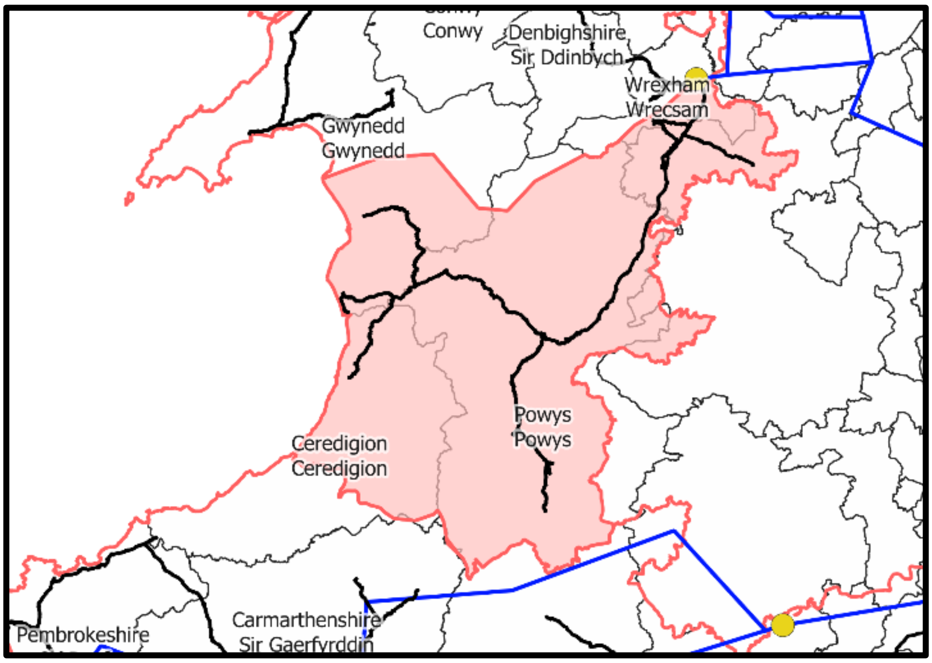


Figure 89: The Mid Wales sub-region at present. The black lines show WWU's high-pressure (HP) network. The approximate route of the national transmission system (NTS) gas pipelines is shown in blue. Yellow circles represent 'offtakes' where gas flows from the NTS to the HP network.

Beyond a pipeline to the offtake in Maelor, there is no NTS in Mid Wales. The local gas distribution network infrastructure serves connections in primarily rural areas across the region. The network configuration is of a linear nature, connecting rural towns to the supply in the northeast of the region.

21.2. KEY INSIGHTS

Analysis undertaken in the Regional Decarbonisation Pathways project has developed a number of key insights for the development of a Net Zero energy system in Mid Wales.

ESC's Strategic Plan (detailed in sections 21.3 to 21.4) found that:

- A high proportion of domestic and business gas network connections are required to be retained under all of the scenarios analysed, driven by the significant uptake of hybrid heating systems and standalone hydrogen boilers. The way the gas grid is used and the volume of hydrogen flowing through it is likely to be very different
- Disconnections from the mains gas for heating are driven by switching to district heating networks. District heat is deployed in the most densely built-up areas where it is most economical, and so disconnections from mains gas are concentrated in such areas, too.
- Across all three scenarios, the quantity of network infrastructure required to serve the retained natural gas and new hydrogen demands in South Wales are the same, though the volume they will supply varies. There is extensive opportunity to use existing infrastructure to serve these demands: both the low and medium pressure networks indicate a high proportion of repurposing.

Costain's Conceptual Plan (detailed in section 21.5) found that:

- The majority of the LTS system in Mid Wales (Figure 55) was constructed from pipe material strength grade of X52 and below. These pipe materials are suited to the transportation of hydrogen and therefore much of the network is suitable for repurposing for hydrogen transportation.
- Due to the small supply volumes and lack of industrial base load, hydrogen production is unlikely to take place in the mid Wales area. Hydrogen is likely to be imported via North Wales.

21.3. STRATEGIC PLAN ANALYSIS (WHOLE SYSTEM MODELLING)

ESC's Strategic Plan analysis has been developed to provide insights into the possible future role of the gas network in Mid-Wales. It uses, as its basis, three whole system energy scenarios developed in collaboration with Wales and West Utilities and Costain, to explore different futures for hydrogen use in the South-West of England and Wales. These three UK-wide, whole energy system scenarios are described in Section 5.5 of the main report and are:

- Consistent with the UK's 2050 Net Zero and interim, statutory carbon targets.
- Identify three levels of hydrogen use for the South-West of England as part of the wider UK energy system.

This section should be read in conjunction with earlier parts of this document, to gain a full understanding for the context for the scenarios and the pathway for the broader whole energy system in Wales, within the wider context of the rest-of the UK energy transition. These three scenarios provide the basis for a strong role for hydrogen. Other scenarios will see less use and some more.

This is the first-time whole system energy modelling has been linked to sub-regional strategic network modelling analysis, to start to understand the potential shape and nature of the Wales and West Utilities (WWU) gas grid in 2050. This is network analysis and insights, based upon whole system modelling and there will be practicalities and engineering constraints faced by hydrogen network conversion. These considerations are further assessed in the sub-regional Conceptual Plans produced by Costain in sections 21.5 below.

This analysis does not replace the need for detailed network modelling and engineering-based feasibility and design but are intended as the basis for analysis and discussion.

21.4. STRATEGIC PLAN KEY INSIGHTS

The key insights for gas and hydrogen networks in Mid-Wales, identified through this Strategic Plan analysis are:

- A high proportion of domestic and business gas network connections are retained in the scenarios, driven by the significant uptake of hybrid heating systems (i.e., heat pumps providing baseload heat and hydrogen boilers providing peaking) and standalone hydrogen boilers. Despite this similarity, the proportion of these systems which are hybrid rather than standalone boilers, is significantly higher in the ELE scenario than in BAL and HYD, and the annual hydrogen consumption is correspondingly lower, as a greater proportion of baseline heat demand is met by electricity.
- District heat is deployed in the most densely built-up areas where it is most economical, and so disconnections from mains gas are concentrated in such areas, too. In BAL, the conurbations around Aberystwyth and Oswestry account for around 90% of the dwellings on district heat networks by 2050.
- The similarity in the number of retained non-industrial connections and industrial fuel switching patterns translates to almost identical requirements for changes to the network infrastructure by 2050 (lengths of new/repurposed pipe etc.) in all three scenarios despite the substantial variation in the amount of hydrogen consumed for heat. While uncertainty around the optimality the level of hybrid heating systems deployment in our modelling means that these interventions cannot be interpreted as a 'low-regret' option, it does illustrate how

systems with quite different amounts of hydrogen consumption could require similar levels of investment to support the transition from gas.

- In all three scenarios, hydrogen production technologies other than electrolysis either require CCS or a site suitable for large scale nuclear plant, and the case for distributed electrolysis is weak due to the decrease in onshore solar and wind generation. Taking these factors into account, our allocation of hydrogen production places no capacity in Mid Wales across the three scenarios. Hydrogen is consumed for heating in Mid Wales in all three scenarios and this is supplied along the existing LTS routes by a mix of new and repurposed pipeline.
- Each scenario explored the quantity of network infrastructure required to serve the retained natural gas and new hydrogen demands. The changes needed for Mid Wales are the same for all three scenarios. A potential opportunity to re-purpose existing natural pipe assets for service in a hydrogen network has been identified. Both the low and medium pressure networks indicate a high proportion of repurposing at 95% (493km) and 100% (93km) respectively of existing pipes.
  In the intermediate and high pressure tiers the opportunity is 80% (368km) and 24% (88km) of existing pipelines respectively. This insight is indicative and should be considered in the context of this modelling. A complete view of the feasibility of repurposing these assets will become available once industry technical, safety and network transition studies are completed.

21.4.1. SCENARIO ANALYSIS

The three whole system scenarios used as the basis of the modelling are the High Electrification (ELE), Balanced (BAL) and High Hydrogen (HYD) which are distinguished by several different assumptions summarised in section 6.1.2. The major distinguishing features of the scenarios (i.e., the results of the modelling) are their relative use of the type of heating system present in 2050:

- The ELE scenario sees a prevalence of electrical systems (heat pumps, electric resistive heaters) to provide heat in residential and non-domestic buildings, and hydrogen can operate in peak demand periods but with a limited load factor. This scenario favours hybrid electric-hydrogen16 systems as a result.
- The BAL scenario, the amount of heat supplied by heat pumps is restricted and hydrogen and electrical systems are set to be equal, reflecting a world where no strong policy is supporting the deployment of heat pumps.
- The HYD scenario assumes that most heat is supplied by hydrogen-based heating systems (hybrid electric-hydrogen systems, hydrogen boilers) and policy supports deployment of hydrogen technology.

Further detail is provided in section 5.5 of the main report.

21.4.1.1. 2050 GASEOUS FUEL SUPPLY, PRODUCTION AND TRANSMISSION

Across the three scenarios explored in this project, both hydrogen and gas have a role within a Net Zero energy system in Mid Wales in 2050. The present natural gas NTS does not extend beyond Maelor into the sub region (Figure 89), supply from this NTS offtake is assumed to be available under all scenarios to the extent that it will meet retained regional natural gas demands in 2050. Given the low quantity of natural gas demand in Mid Wales, this could be uneconomical for

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[16] Hybrid systems use heat pumps to provide baseload heating and hydrogen boilers to provide peaking.

distribution or transmission network. Resulting in impact on retained natural gas network and the transition to hydrogen discussed below. Further economic analysis assessing the value of demand and costs of network retention is required.

Whilst there is hydrogen demand in Mid Wales, the analysis has shown that there are locations within the WWU region which are more suitable for hydrogen production, resulting in no production within the sub region within this analysis. Details of this method are discussed in section 7 of the accompanying report. A 2050 supply of hydrogen to Mid Wales is assumed to be sourced from a hydrogen transmission system offtake in the vicinity of the existing natural gas offtake. All hydrogen consumed in Mid Wales in would be delivered by the distribution network from this supply point.

21.4.1.2. GASEOUS FUEL CONSUMPTION

Our modelling indicates that Mid Wales contains a single large industrial site considered to have ongoing natural gas demand in 2050. This site is assumed to be retained out to 2050, however continued operation will ultimately be subject to a range of other economic factors, including the future of the energy system. It is assumed that all other industrial sites in Mid Wales can, and have, made the switch to hydrogen by 2050 supporting wider network transition. Practically the switchover of industrial demands during network transition is likely to be complex, requiring consideration of both local network and stakeholder factors. Additional commercial and engineering analysis is required to identify interdependencies and understand how these can be managed to optimise network transition. Further details of how industrial demand has been modelled is provided in section 4.

For the scenarios explored, domestic and commercial gas demand for space heating and hot water is replaced by a combination of hydrogen, electricity, and heat network-based heating solutions. Gas boilers are displaced by hydrogen boilers, hybrid hydrogen heat pumps, heat interface units for heat networks and electric resistive heating. The combination of these is an output of the regional strategic modelling (see section 6.2.7) and depends somewhat on the underlying assumptions informing each scenario.

Typically, in the ELE scenario, the bulk of the heat is supplied by electric heating systems, and hydrogen boilers are limited to backup operation at peak times. the presence of district heating is conditioned by the density of buildings, making it more economical in denser areas where the transportation losses are reduced. The adoption of heat network is the main driver to disconnection from the gas network in 2050.

From a whole system perspective, hybrid boilers are valuable, reducing the capacity and associated cost of heat pumps whilst mitigating the expense of meeting high electricity peak demands and utilising existing infrastructure assets and low-cost storage. However, further work is required to understand the impact of network maintenance costs and the transitional capital costs to realise least cost system designs.

Notable differences identified between the scenarios include a much higher proportion of total heat production throughout the year due to Hydrogen boilers in HYD than in BAL, and in BAL than in ELE. Based on this analysis, switching from mains gas to district heating is the only driver of disconnection of non-industrial meters considered across all three scenarios.

21.4.1.3. CHANGES TO THE GASEOUS DISTRIBUTION NETWORKS

Non-industrial connections and low-pressure networks

Within Mid Wales, all three scenarios tested suggest that 6-7% of domestic and commercial connections are removed and the remaining number switch from natural gas to hydrogen. Between 5% and 6% of the Low Pressure (LP) gas network is decommissioned. Where connections switch away from a hydrogen supply, between 5-6% of homes across all three scenarios, they have their heating provided through district heating in 2050 – see section 7 for further explanation.

These modelling outputs suggests that large volumes of connections and LP network are retained across the scenarios, care is advised when interpreting this insight. The modelling method used is based on a breakdown of a least cost whole energy system for the UK to a regional level such as Mid Wales. Resulting in retention of parts of the gaseous network which may be uneconomical in some scenarios. Further technical and economic analysis is required to obtain additional understanding of the interaction between local, regional, and national networks to enable cost optimal system design at each level. The scenarios here have indicated that where volumes of hydrogen reach low levels there could be a requirement to consider economic optimisation by assessment of further options between different levels of geographic granularity.

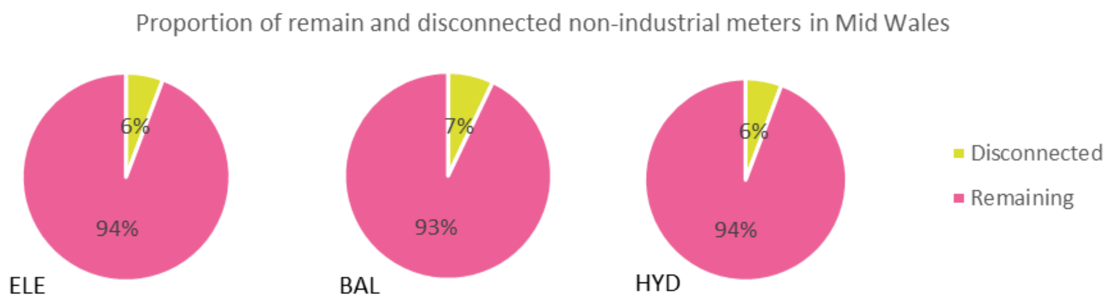

Figure 90: non-industrial disconnected and remaining meters (total number: 45,529)

Service pipes link the LP network to individual properties. A H21 project report[17] suggested a proportion of these could require replacement due to the higher volumetric flows of hydrogen required to supply a given amount of energy. There is significant uncertainty around this issue, and it has been suggested that many of these works could be avoided by various network level solutions, however this could have significant implications for customers. An estimated range of service pipe replacements for Mid Wales is 21,000 to 47,000 across all three scenarios.

Medium, intermediate and high-pressure networks

Each scenario explored has an associated 'Bill of Quantities', indicating the quantity of infrastructure needed, summarised in Figure 91. This is the same for all three scenarios in Mid Wales, discussed in section 7. Values are given as a percentage of the length of currently existing network for each respective pressure tiers – these are of 308km for the HP network, 82km for the IP network, and 93km of MP network.

In modelling the transition of networks from the network as it is today to one indicative of that required to serve the 2050 scenarios, the method re-purposes as much of the existing natural gas

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[17] NIA 275 H21 – Hydrogen Ready Services (https://h21.green/app/uploads/2021/02/NIA-275-H21-Hydrogen-Ready-Services-Final-Version.pdf) [Accessed 24/03/2022]

network for hydrogen service as possible. This was done whilst considering the need to maintain a natural gas supply through the transition and practical switching constraints of connections dependent on a natural gas supply to one receiving hydrogen. The result is an increased quantity of repurposing that is considered generous and reduced amount of new hydrogen. Transition of gas networks is recognised as a highly complex process and further analysis is required to fully understand the influencing factors to inform decisions. The detail of the modelling logic is provided in section 7.

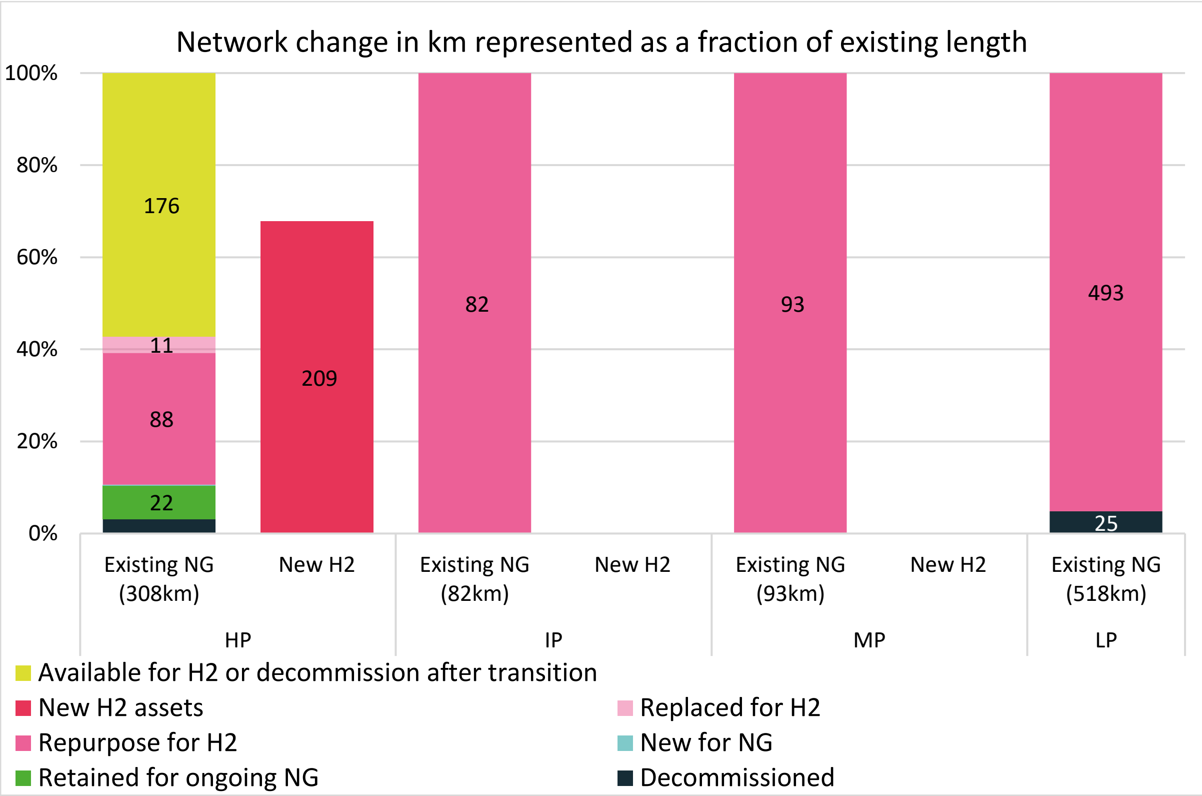


Figure 91: Network changes as a percentage of existing pressure tier length

Medium and Intermediate Pressure

The gas network in Mid Wales is dominated by HP in length, with long sections stretching across the region to supply relatively low demand levels. The MP and IP networks mostly consist of the last kilometers to points of demand. There are occasional IP assets running parallel to HP pipes. In addition, there is only one remaining natural gas demand site in 2050, which is supplied directly by HP. For these reasons, the IP and MP networks are not constrained by remaining ongoing natural gas demand, nor by transition constraints, due to the low number of connections in the area. As a result, the entire MP and IP networks could be repurposed to hydrogen service in 2050, and potentially no additional new build required.

High Pressure

The HP network in Mid-Wales has a nearly perfect radial structure (Figure 89) with long stretches of pipes across the sub-region, linking to the NTS offtake. One implication of this structure is the lack of redundancy, meaning that a large proportion of the connections can depend entirely on a unique section of pipes. This explains the high proportion (nearly 60%) of HP assets required for transition, bearing in mind that these assets would be made available either for reinforcement, storage or decommission in 2050, after the transition. Further detailed network analysis of gas flows would be useful to inform the decision between these possible outcomes.

Around 7% of the HP network length is needed to retain on natural gas, to connect the remaining single large industrial demand with the nearest offtake located at Pentre Maelor.

Slightly more than 5% of the assets are considered vintage and will therefore have to be either replaced for hydrogen service or decommissioned by 2050. Finally, the above leads to around 29% of the existing network which could be repurpose to hydrogen, corresponding to a need for new hydrogen network representing more than 68% of the length of the existing HP network.

21.5. CONCEPTUAL PLAN

The Conceptual Sub Regional Pull Outs are based on engineering analysis which considers the implications of the scenarios for natural gas and hydrogen infrastructure. This provides a basis to understand the decisions which are required around investment in network infrastructure to support decarbonisation and, provide an indicative illustration of the uptake of conversion of Domestic and Commercial meters to hydrogen between 2020 and 2050, across the three scenarios.

21.5.1. KEY INSIGHTS

- Due to the small supply volumes and lack of industrial base load, hydrogen production is unlikely to take place in the mid Wales area. Hydrogen is likely to be imported via North Wales, initially from HyNet in Cheshire and later from hydrogen generation within North Wales once production starts there. The relatively close proximity of the North Wales supply area to the gas storage facilities in Cheshire will allow this local supply area to have access to these facilities for seasonal and diurnal storage requirements.
- Potential to Repurpose: The majority of the LTS system in Mid Wales (Figure 55) was constructed from pipe material strength grade of X52 and below. These pipe materials are suited to the transportation of hydrogen. There are relatively few sections of the network in North Wales which are over fifty years old. Some of the older pipelines may also have been used for Towns Gas service, which can also suffer from further degradation due to the effect of hydrogen on the pipe wall. Where these pipelines are to be replaced then it is recommended that they are replaced with pipelines suitably sized and with a pipe material grade which suitable for hydrogen service.
- Conversion of mid Wales is likely to be driven as sub region of the North Wales area. There is only one major emitter in the area fed by the mid Wales network and they are located close to NTS offtake and the North Wales supply area. Conversion is likely to place as hydrogen becomes available at the Maelor offtake.

Table 20. Mid Wales Meters Converted per 5 Year Cycle

Mid Wales	Number of Meters Converted per 5 Year Cycle						
	2020	2025	2030	2035	2040	2045	2050
High Electrification	0	0	0	0	256	0	0
Balanced	0	0	44	93	104	16	0
High Hydrogen	0	0	55	154	50	0	0

- All three scenarios in Mid Wales will require similar levels of new pipeline infrastructure to enable conversion to hydrogen. In total approximately 120 km of new high pressure LTS hydrogen pipeline would be required in Mid Wales by 2045.

Table 21. Mid Wales Approximate KM of New Hydrogen Pipeline per 5 Year Cycle

Mid Wales	KM of New Hydrogen Pipeline per 5 Year Cycle						
	2020	2025	2030	2035	2040	2045	2050
High Electrification Scenario	0	0	0	88.4	31.5	0	0
Balanced & High Hydrogen Scenarios	0	0	88.4	0	31.5	0	0

21.5.2. BALANCED (BAL)

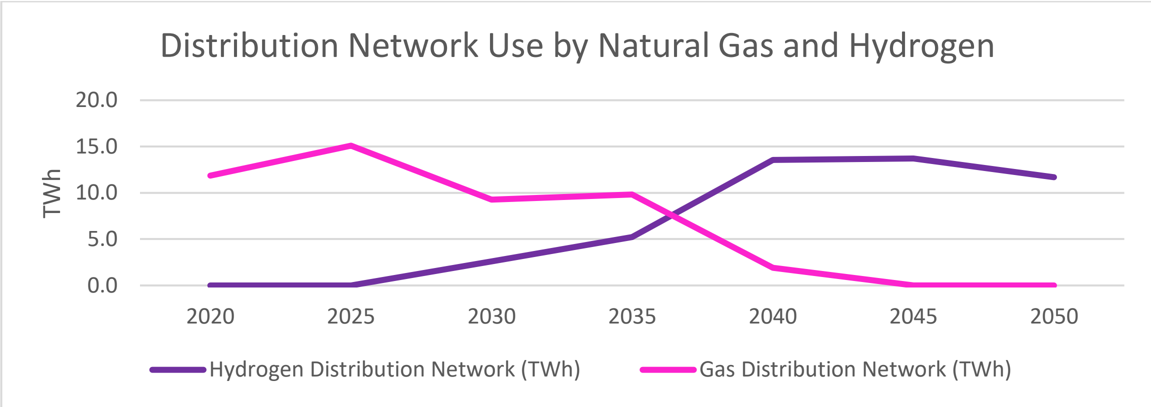
Table 14.3 shows the forecast hydrogen production and, distribution network consumption of natural gas and hydrogen for the Balanced (BAL) WWU scenario modelled in ESME in Wales. It can be seen that Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Initially hydrogen is supplied to industrial users and starts to be supplied to the distribution system from 2030 with the system supplying the maximum predicted hydrogen demand in 2045. Before consumption drops away towards 2050. Conversion of the Distribution Network is completed shortly after 2040.

Table 22. Wales Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

Wales	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.8	1.2	5.9	11.3	47.8	42.2	33.4
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	2.6	5.2	13.5	13.7	11.7
Natural Gas Consumption from Distribution Network (TWh)	11.9	15.1	9.3	9.8	1.9	0.0	0.0

Figure 92 Wales Distribution Network Use by Natural Gas and Hydrogen – Balanced



As detailed in Section 10, there only one large emitter dominate in the area. Figure 93 shows the NAEI Sector and emission tonnage for the major emitters of carbon dioxide in Mid Wales.

Figure 93 Mid Wales - NAEI Large Emitters by Sector and Emissions Tonnage

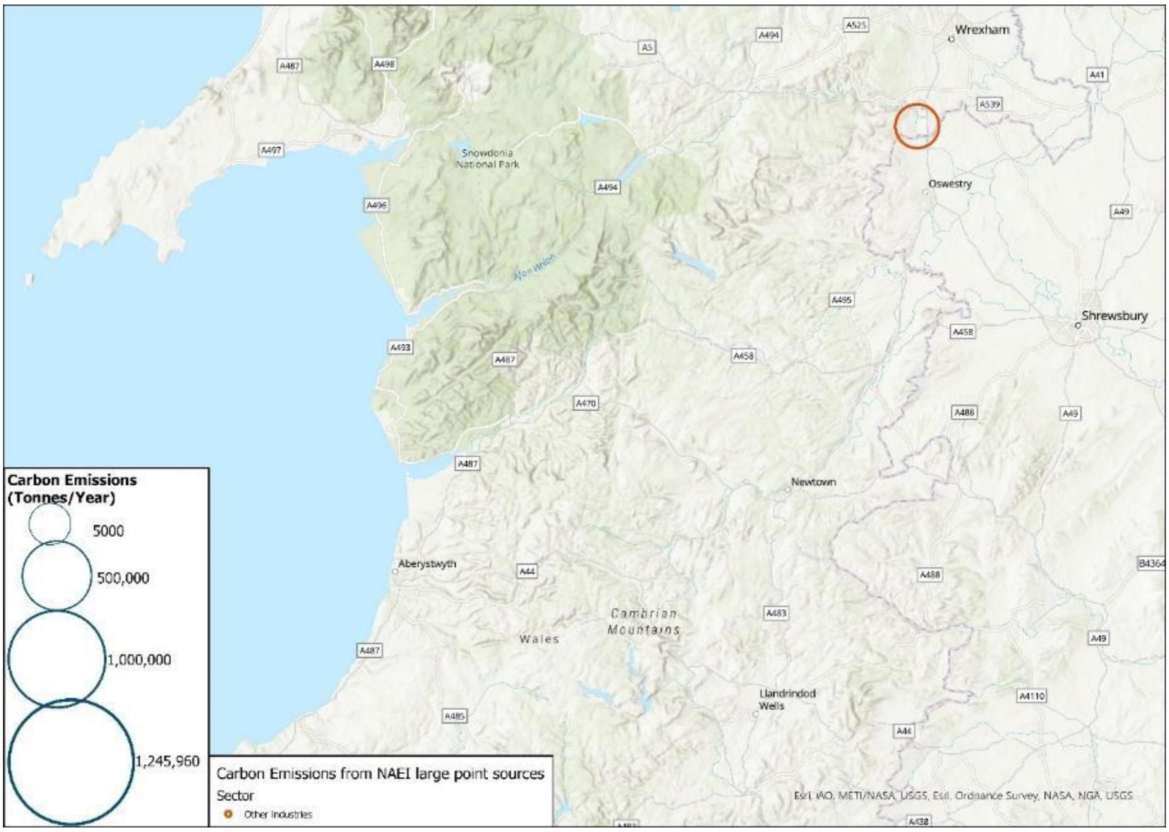


Table 23 shows the forecast number of Mid Wales meter points that require converting from natural gas and hydrogen on the distribution network for the Balanced (BAL) scenario.

Table 23. Mid Wales Meters Converted per 5 Year Cycle – Balanced

Mid Wales	Number of Meters Converted per 5 Year Cycle – Balanced						
	2020	2025	2030	2035	2040	2045	2050
Maelor Mid	0	0	8870	18500	20807	3114	0
Meters Converting per Week (40 Wks/Year)	0	0	44	93	104	16	0

It should be noted that the number of meters requiring conversion each week is based on the assumption that conversion will take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

Figure 94 2030 Balanced - Domestic and Commercial Meters

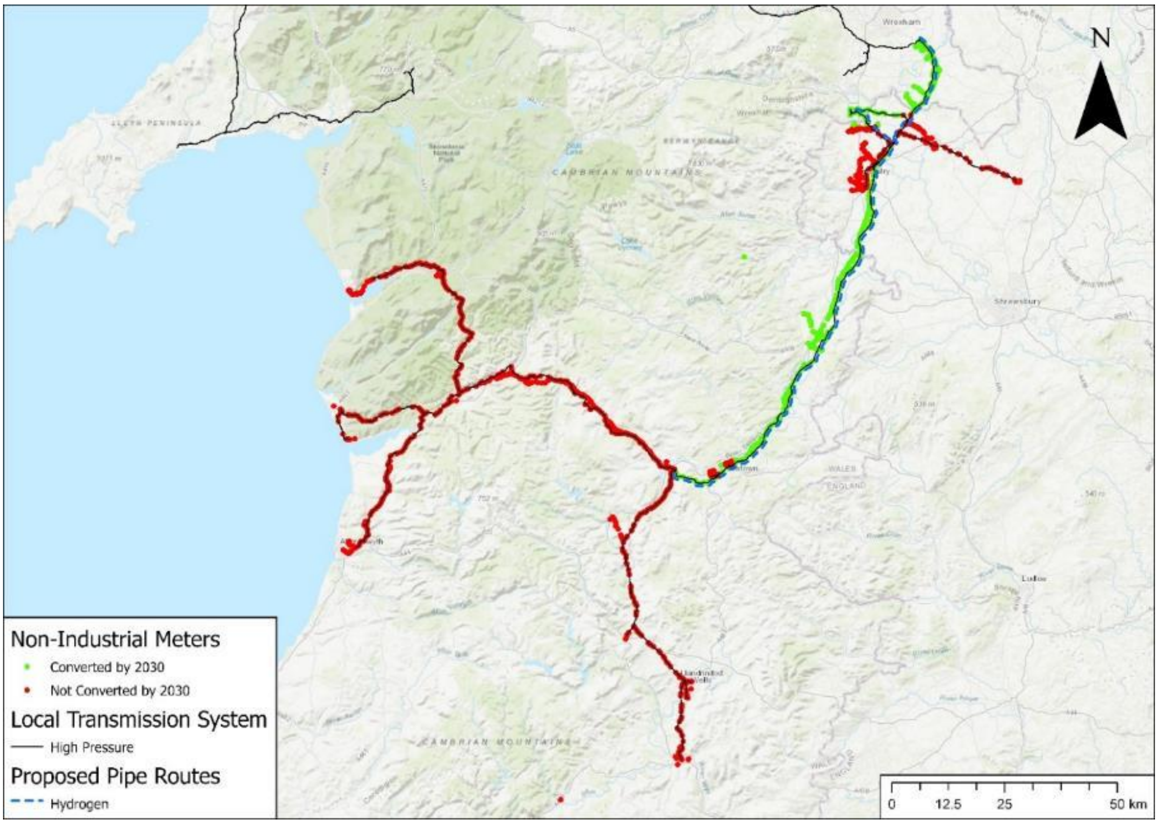


Figure 95 2035 Balanced - Domestic and Commercial Meters

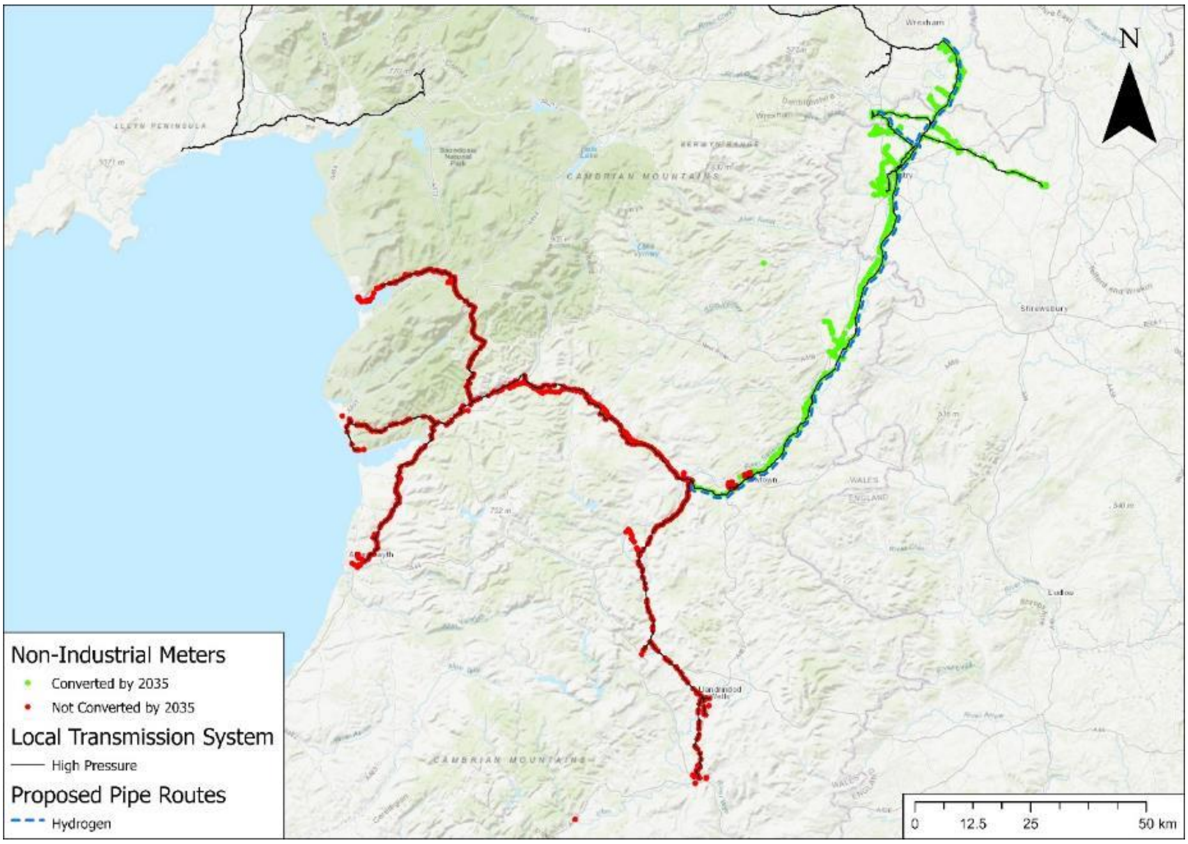


Figure 96 2040 Balanced - Domestic and Commercial Meters

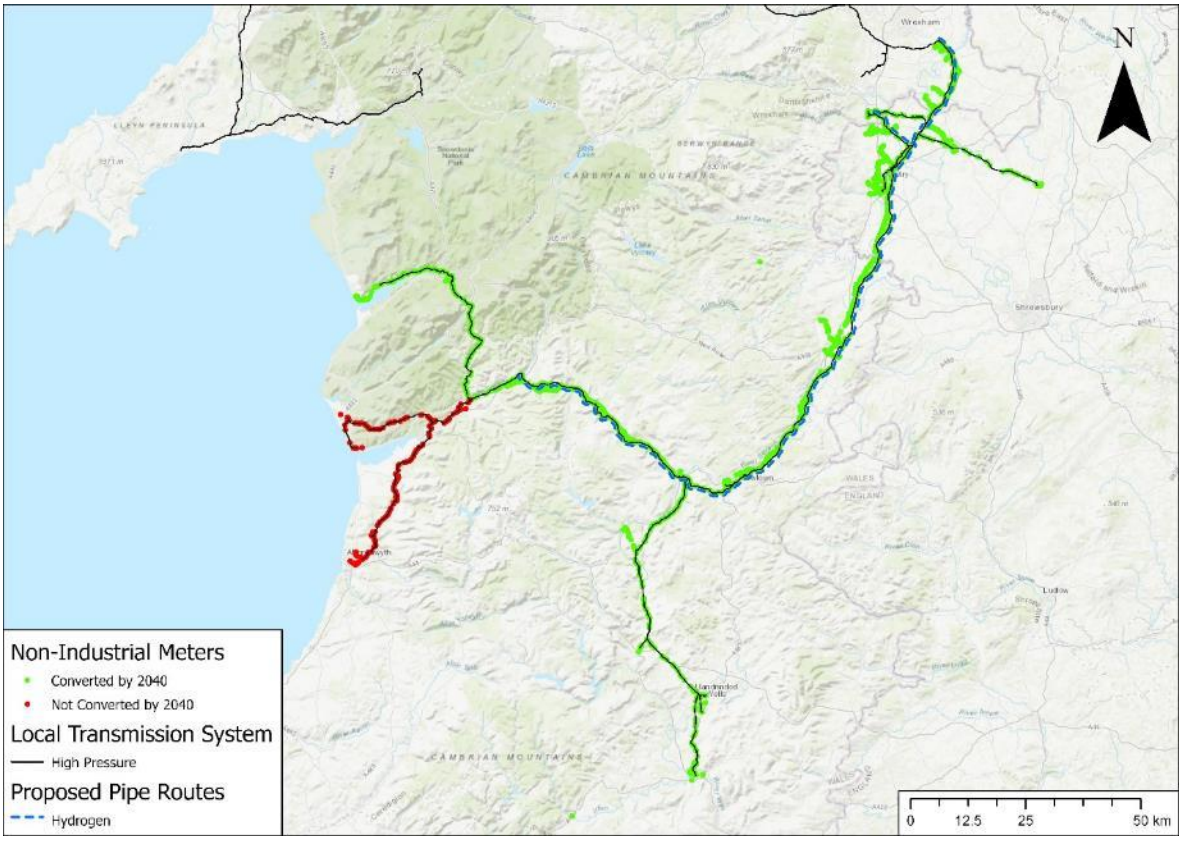


Figure 97 2045 – 2050 Balanced - Domestic and Commercial Meters

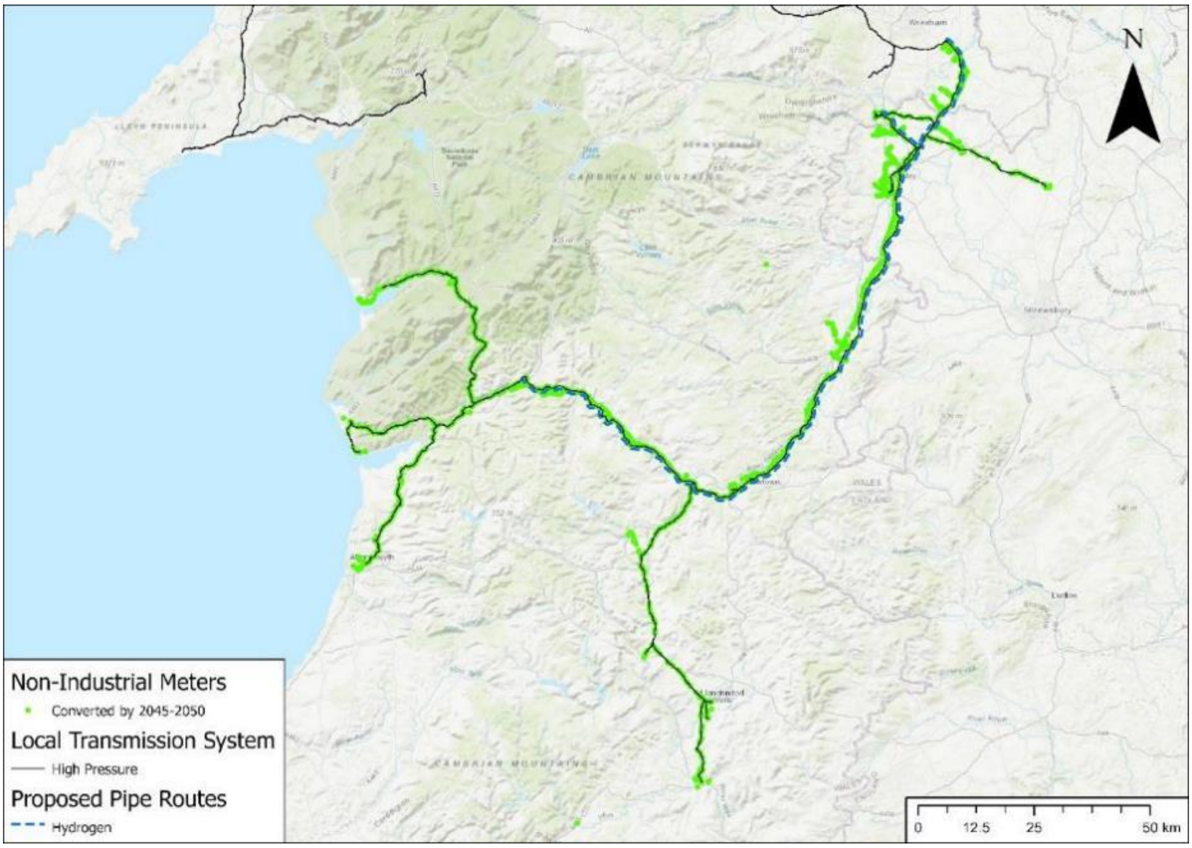
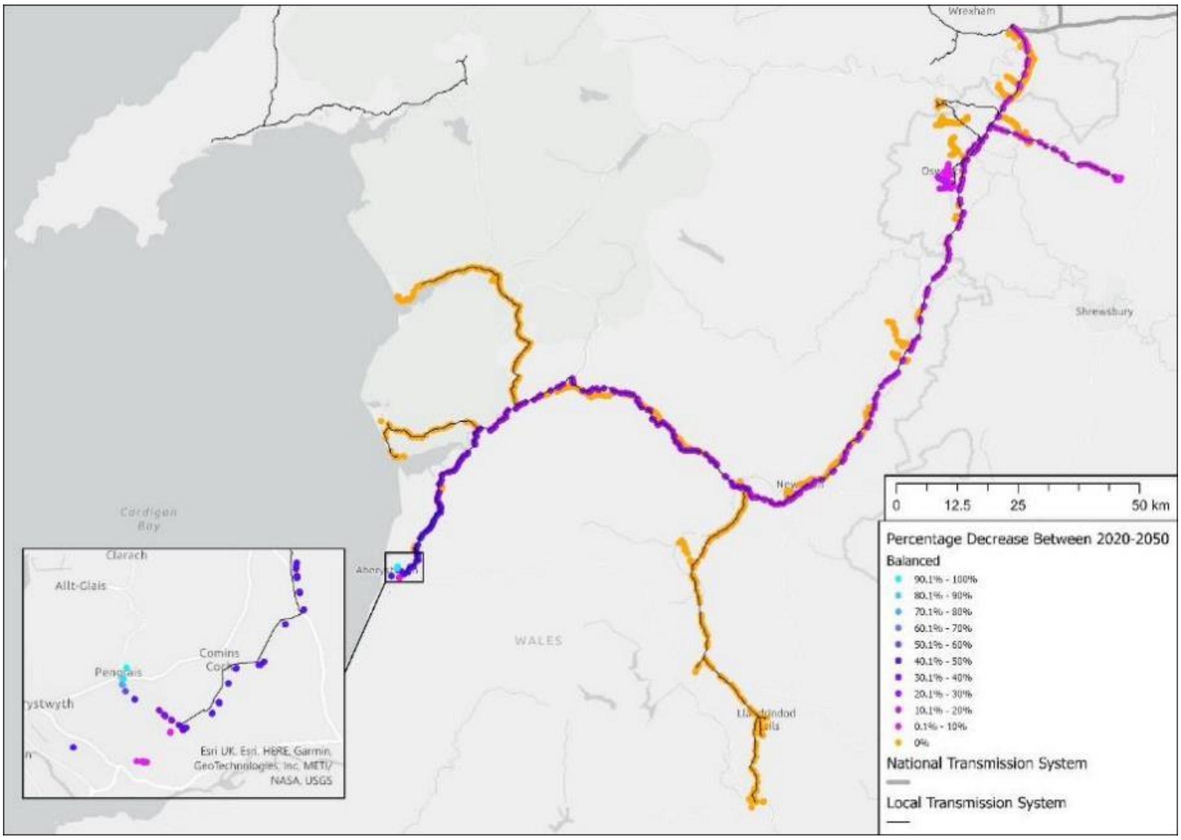


Figure 98 % Change in the Domestic and Commercial Meters – Balanced in 2050



Under the Balanced scenario there will be an approximate 6% reduction in the number of non dependent meters. Figure 98 details the areas where there is predicted to be a fall in the number of customers on the gas system. A higher proportion of meters are lost in the centre of Aberystwyth, where district heating takes over as the source of domestic heat load.

21.5.3. COMPARISON OF THE THREE SCENARIOS

According to the ESME Whole System Overview (Section 6.2), for all three scenarios hydrogen production ramps up and peaks in similar timescales. Production of hydrogen and hydrogen consumption from the distribution network are broadly similar for High hydrogen (113% of balanced). However, in the High electrification case production of hydrogen and hydrogen consumption from the distribution network is lower than the Balanced scenario (78% of Balanced). As the number of domestic meters is broadly the same across all three scenarios, this would indicate that individual consumption is the primary variable rather than the number of supply points. As can be seen from Figure 98, there are falls in the number of domestic meters in the major conurbations and this is broadly reflected across all three scenarios with a slightly greater reduction in the numbers of meters in the High Electrification scenario.

The quantity of new pipeline required will be similar across all three scenarios, due in part to the requirements for the system to be able to supply peak demand. However, for the High Electrification case, pipeline diameters may be slightly smaller than those required for the High Hydrogen and Balanced scenarios.

Details of the Conceptual Plan analysis of Electrification and High Hydrogen scenarios can be found in Section E.

SECTION D -
SUB-REGIONAL ANALYSIS

SOUTH WALES PULL OUT*

* This sub-regional analysis should be read in conjunction with Parts A, B and C of the report

22. SUB-REGIONAL NETWORK ANALYSIS – SOUTH WALES

This sub-section of the report provides further interpretation for the sub-region of South Wales of the whole systems modelling undertaken by the Energy Systems Catapult (ESC's) in Sections 6 and 7 and the engineering analysis undertaken by Costain in Sections 10 to 16 of the main report.

The South Wales analysis is structured in a similar way to the earlier sections of the report, with the implications of ESC's modelling set out in a Strategic Plan sub-section (see section 22.3) and the Costain engineering analysis set out in a Conceptual Plan section (see section 22.5). In advance of both these sub-sections, an overview of the key features of South Wales is provided (see Section 22.1).

22.1. OVERVIEW OF SOUTH WALES

The South Wales sub-region corresponds directly to the WWU South Wales license area (Figure 99). It has the highest population of the sub-regions modelled and currently contains over 900,000 non-industrial gas meter points. It also contains major concentrated industrial sites with considerable energy requirements in the south. Large rural areas define the North and East, including the Brecon Beacons National Park.

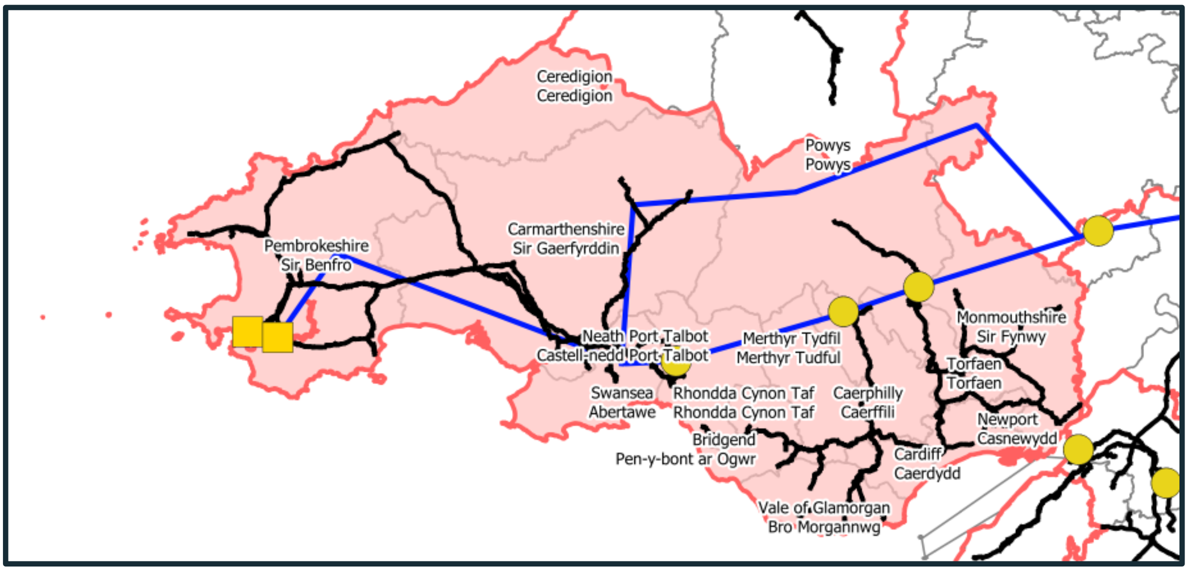


Figure 99: The South Wales sub-region at present. The black lines show WWU's high-pressure (HP) network. The approximate route of the national transmission system (NTS) gas pipelines is shown in blue. Yellow circles represent 'offtakes' where gas flows from the NTS to the HP network. The yellow squares in the west are the two LNG regasification terminals at Milford Haven.

South Wales has well established natural gas infrastructure, including the LNG terminals at Milford Haven in Pembrokeshire. These play an important role in Welsh and UK gas supply and can provide up to 25% of the UK's total demand. The National Transmission System (NTS) runs east to west through the region, providing distribution offtakes in the east. Local gas distribution network infrastructure serves connections in urban, sub-urban and rural areas across the region. Density of network assets are greatest around the conurbations and industrial areas in the south-east of the region, where highly interconnected networks are common. The rural and valley areas are supplied by parts of the network with linear characteristics, as opposed to one which is interconnected.

22.2. KEY INSIGHTS

Analysis undertaken in the Regional Decarbonisation Pathways project has developed a number of key insights for the development of a Net Zero energy system in South Wales.

ESC's Strategic Plan (detailed in sections 22.3 to 22.4) found that:

- A high proportion of domestic and business gas network connections are required to be retained under all of the scenarios analysed, driven by the significant uptake of hybrid heating systems and standalone hydrogen boilers. The way the gas grid is used and the volume of hydrogen flowing through it is likely to be very different.
- Disconnections from the mains gas for heating are driven by switching to district heating networks. District heat is deployed in the most densely built-up areas where it is most economical, and so disconnections from mains gas are concentrated in such areas, too.
- Across all three scenarios, the quantity of network infrastructure required to serve the retained natural gas and new hydrogen demands in South Wales are the same, though the volume they will supply varies. There is extensive opportunity to use existing infrastructure to serve these demands: both the low and medium pressure networks indicate a high proportion of repurposing.

Costain's Conceptual Plan (detailed in section 22.5) found that:

- South Wales is likely to be a potential exporter of hydrogen to England both within the WWU supply area to the South West and to the Midlands. Opportunities for 'blue' production technologies and BECCS appear in Wales and these are concentrated entirely at ports in South Wales. Milford Haven is also one of the indicative sites in Wales to which there is potential for hydrogen production by electrolysis.
- A small number of larger emitters dominate present industrial emissions which are generally located in close proximity to the South Wales coast. The decisions taken by the major emitters to decarbonise their emissions will have a significant impact on the energy transition solutions deployed in the region, and the timing of the infrastructure developments required.

22.3. STRATEGIC PLAN ANALYSIS (WHOLE SYSTEM MODELLING)

ESC's Strategic Plan analysis has been developed to provide insights into the possible future role of the gas network in South Wales. It uses, as its basis, three whole system energy scenarios developed in collaboration with Wales and West Utilities and Costain, to explore different futures for hydrogen use in the South-West of England and Wales. These three UK-wide, whole energy system scenarios are described in Section 5.5 of the main report and are:

- Consistent with the UK's 2050 Net Zero and interim, statutory carbon targets.
- Identify three levels of hydrogen use for the South-West of England as part of the wider UK energy system.

This section should be read in conjunction with earlier parts of this document, to gain a full understanding for the context for the scenarios and the pathway for the broader whole energy system in Wales, within the wider context of the rest-of the UK energy transition. These three scenarios provide the basis for a strong role for hydrogen. Other scenarios will see less use and some more.

This is the first-time whole system energy modelling has been linked to sub-regional strategic network modelling analysis, to start to understand the potential shape and nature of the Wales and West Utilities (WWU) gas grid in 2050. This is network analysis and insights, based upon whole system modelling and there will be practicalities and engineering constraints faced by hydrogen network conversion. These considerations are further assessed in the sub-regional Conceptual Plans produced by Costain in sections 22.5 below.

This analysis does not replace the need for detailed network modelling and engineering-based feasibility and design but are intended as the basis for analysis and discussion.

22.4. STRATEGIC PLAN INSIGHTS

The key insights for gas and hydrogen networks in South Wales, identified through this Strategic Plan analysis are:

- A high proportion of domestic and business gas network connections are retained in the scenarios, driven by the significant uptake of hybrid heating systems (i.e., heat pumps providing baseload heat and hydrogen boilers providing peaking) and standalone hydrogen boilers. Despite this similarity, the proportion of these systems which are hybrid rather than standalone boilers, is significantly higher in the ELE scenario than in BAL and HYD, and the annual hydrogen consumption is correspondingly lower, as a greater proportion of baseline heat demand is met by electricity.
- District heat is deployed in the most densely built-up areas where it is most economical, and so disconnections from mains gas are concentrated in such areas, too. In BAL for example, the Cardiff, Newport, and Swansea Unitary Authorities together contain around 80% of the dwellings on district heat networks by 2050.
- The similarity in the number of retained non-industrial connections and industrial fuel switching patterns translates to almost identical requirements for changes to the network infrastructure by 2050 (lengths of new/repurposed pipe etc.) in all three scenarios despite the substantial variation in the amount of hydrogen consumed for heat. While uncertainty around the optimality the level of hybrid heating systems deployment in our modelling means that these interventions cannot be interpreted as a 'low-regret' option, it does

illustrate how systems with quite different amounts of hydrogen consumption could require similar levels of investment to support the transition from gas.

- Hydrogen production by 'blue' production technologies and BECCS appear in Wales in all three scenarios and in all scenarios, these are concentrated entirely at ports in South Wales on the basis of the availability of infrastructure for the shipping of captured carbon and, in the case of 'blue' production, natural gas supply. Milford Haven is also one of two indicative sites in Wales to which hydrogen production by electrolysis is allocated on the basis that grid connected electrolysis near here would complement offshore wind generation, but this technology only features in the BAL and HYD scenarios.
- Each scenario explored the quantity of network infrastructure required to serve the retained natural gas and new hydrogen demands. The changes needed for South Wales are the same for all three scenarios. A potential opportunity to re-purpose existing natural pipe assets for service in a hydrogen network has been identified. Both the low and medium pressure networks indicate a high proportion of repurposing at 93% (7,929km) and 92% (861km) respectively of existing pipes.

  In the intermediate and high pressure tiers the opportunity is 73% (298km) and 34% (277km) of existing pipelines respectively. This insight is indicative and should be considered in the context of this modelling. A complete view of the feasibility of repurposing these assets will become available once industry technical, safety and network transition studies are completed.

22.4.1. SCENARIO ANALYSIS

The three whole system scenarios used as the basis of the modelling are the High Electrification (ELE), Balanced (BAL) and High Hydrogen (HYD) which are distinguished by several different assumptions, summarised in section 6.1.2. The major distinguishing features of the scenarios (i.e., the results of the modelling) are their relative use of the type of heating system present in 2050:

- The ELE scenario sees a prevalence of electrical systems (heat pumps, electric resistive heaters) to provide heat in residential and non-domestic buildings, and hydrogen can operate in peak demand periods but with a limited load factor. This scenario favours hybrid electric-hydrogen[18] systems as a result.
- The BAL scenario, the amount of heat supplied by heat pumps is restricted and hydrogen and electrical systems are set to be equal, reflecting a world where no strong policy is supporting the deployment of heat pumps, and consumer preference limits their uptake.
- The HYD scenario assumes that most heat is supplied by hydrogen-based heating systems (hybrid electric-hydrogen heating systems and hydrogen boilers) and policy supports deployment of hydrogen technology.

Further detail about the scenarios is provided in section 5.5 of the main report.

22.4.1.1. 2050 GASEOUS FUEL SUPPLY, PRODUCTION AND TRANSMISSION

Across the three scenarios explored in this project, both hydrogen and natural gas have a role within a Net Zero energy system in South Wales in 2050. Natural gas is utilised in industry and for

[18] Hybrid systems use heat pumps to provide baseload heating and hydrogen boilers to provide peaking.

hydrogen production, but a further explanation of its continued use in 2050 is provided in section 6.2.6.

It is assumed that the LNG regasification terminals in Milford Haven remain a significant source of natural gas supply through to 2050 for South Wales and that they remain connected to the rest of the country by the existing NTS. In energy terms, across the three scenarios, they supply between 37 TWh and 41 TWh of natural gas per year in 2050. The only natural gas production, as opposed to import, of methane-based gaseous fuel in Wales is via Anaerobic Digestion (AD), which produces less than 0.25% of the LNG import in each of the three scenarios.

As discussed in section 7, modelling of the Welsh gaseous networks includes flows of natural gas and hydrogen between Wales and adjacent regions of England over separate transmission infrastructure. In all three scenarios, Wales is a net-exporter of both natural gas and hydrogen. The transmission infrastructure and the distribution of production between South and North Wales considered in the models imply that all exports of natural gas and most exports of hydrogen would come from South Wales. A natural gas NTS is assumed to be available under all scenarios to the extent that it will meet residual natural gas demands in 2050, including all offtakes to the distribution system in South Wales.

While some natural gas continues to be used by industry in 2050 across all three scenarios, most natural gas consumed in South Wales is used as a feedstock for 'blue' hydrogen production[19]. This is one of the drivers for retention of the high-pressure tier of the natural gas networks in South Wales in the scenarios explored meaning that in the event the case for blue hydrogen were to change, through influencing factors such as cost of natural gas, a different network requirement may emerge. This could subsequently have an impact on the economics of hydrogen networks and development through the transition.

Blue hydrogen production in Wales has been assumed to be located exclusively in the South Wales subregion. Where it benefits from the natural gas source at Milford Haven, proximity to demand, the existing NTS corridors, and to ports for shipping of captured carbon to potential storage sites located off the coast of the North of England. We have further assumed that this blue hydrogen production capacity would be distributed between indicative sites at Milford Haven, Port Talbot, and Barry. They benefit from some or all the following factors: proximity to population centres, industrial demand nodes, and port infrastructures.

[19] 'Blue' meaning that the production process yields carbon dioxide which is captured and stored.

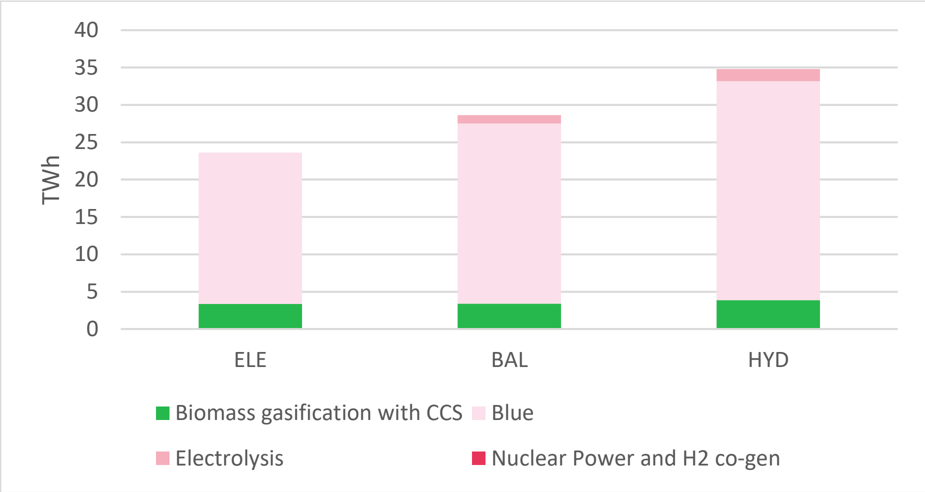


Figure 100: Annual hydrogen production in South Wales in 2050 by scenario (TWh)

Hydrogen production using biomass with carbon capture and storage (CCS) - a negative emissions technology - has been assumed to be distributed in the same way, for similar reasons. 50% of the modelled capacity of green hydrogen production (i.e., by electrolysis) in Wales is assumed to be at Milford Haven. The rationale is that Milford Haven is likely to be near onshoring points for electricity generated by offshore wind farms, particularly in the Celtic Sea. The absence of electrolytic production in the ELE scenario reflects its absence from Wales in this scenario, which is discussed in section 6.2.2.

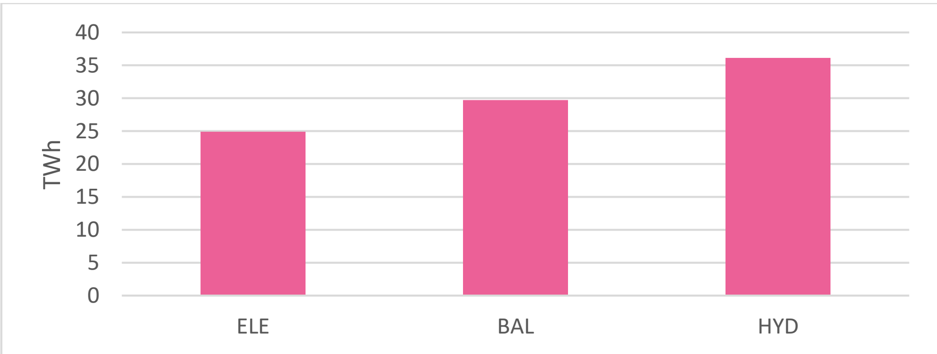


Figure 101: Natural gas consumption from blue hydrogen production in 2050 by scenario (TWh)

It is assumed that a new or repurposed hydrogen NTS is also present in 2050 providing supply to the locale of existing offtake points for onward supply through a hydrogen distribution network. Given the centralised nature of hydrogen production across the scenarios (i.e., predominantly blue hydrogen production), offtakes from the hydrogen NTS represents an important source of hydrogen for the distribution networks.

22.4.1.2. GASEOUS FUEL CONSUMPTION

Industrial

South Wales contains major industrial sites in all four of the industrial sectors considered to have ongoing natural gas demand in 2050: refineries, chemicals, paper mills, and iron, steel, and non-ferrous metals. These are assumed to all remain in 2050 in all scenarios, however their continued operation will ultimately be subject to a range of other economic factors, including the future of the energy system. Further detail on the retained natural gas demand is provided at section 6.2.

It is assumed that all sites in other industrial sectors can switch to hydrogen by 2050, supporting wider network transition. Practically the switchover of industrial demands during network transition is likely to be complex, requiring consideration of both local network and stakeholder factors. Additional commercial and engineering analysis is required to identify interdependencies and understand how these can be managed to optimise network transition. Further details of how industrial demand has been modelled is provided in section 7.2.2.

Non-industrial

For the scenarios explored, domestic and commercial gas demand for space heating and hot water is replaced by a combination of hydrogen, electricity, and heat network-based heating solutions. Gas boilers are displaced by hydrogen boilers, hybrid hydrogen heat pumps, heat interface units for heat networks and electric resistive heating. The combination of these is an output of the regional strategic modelling (see section 6.2.7) and depends somewhat on the underlying assumptions informing each scenario.

Typically, in the ELE scenario, the bulk of the heat is supplied by electric heating systems, and hydrogen boilers are limited to backup operation during higher demand periods. the presence of district heating is conditioned by the density type of buildings, making it more economical in denser areas where the transportation losses are reduced. The adoption of heat network is the main driver to disconnection from the gas network in 2050.

From a whole system perspective, hybrid boilers are valuable, reducing the capacity and associated cost of heat pumps whilst mitigating the expense of meeting high electricity peak demands and utilising existing infrastructure assets and low-cost storage. However, further work is required to understand the impact of network maintenance costs and the transitional capital costs to realise least cost system designs.

Notable differences identified between the scenarios include a much higher proportion of total heat production throughout the year due to Hydrogen boilers in HYD than in BAL, and in BAL than in ELE. Based on this analysis, switching from mains gas to district heating is the only driver of disconnection of non-industrial meters considered across all three scenarios.

22.4.1.3. CHANGES TO THE GASEOUS DISTRIBUTION NETWORKS

Non-industrial connections and low-pressure networks

Within South Wales, all three scenarios tested suggest that 8-9% of domestic and commercial connections are removed and the remaining number switch from natural gas to hydrogen. In all three scenarios, 7% of the Low Pressure (LP) gas network is decommissioned. Where connections switch away from a hydrogen supply, approximately 9% of homes across all three scenarios, have their heating provided through district heating in 2050 – see section 7 for more detail on the method.

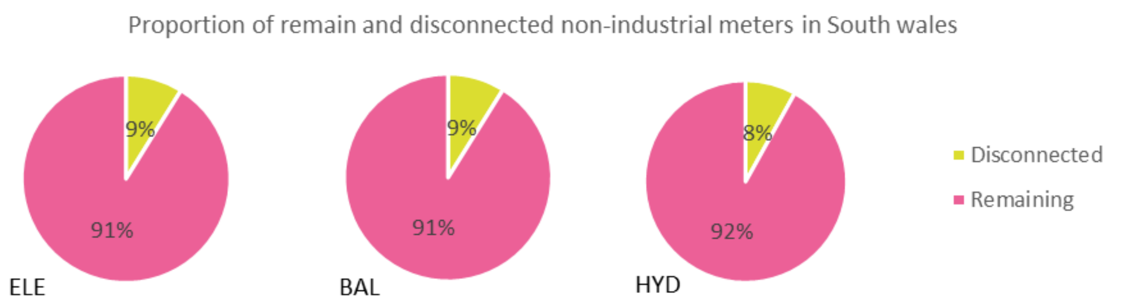


Figure 102 - Non-industrial disconnected and remaining meters in South Wales (total number: 915,454)

These modelling outputs suggests that large volumes of connections and LP gas network are retained across the scenarios, care is advised when interpreting this insight. The modelling method used is based on a breakdown of a least cost whole energy system for the UK to a regional level such as South Wales. Resulting in retention of parts of the gas network which may be uneconomical in some scenarios. Further technical and economic analysis is required to obtain additional understanding of the interaction between local, regional, and national networks to enable cost optimal system design at each level. The scenarios here have indicated that where volumes of hydrogen reach low levels there could be a requirement to consider economic optimisation by assessment of further options between different levels of geographic granularity.

Service pipes link the LP network to individual properties. A H21 project report[20] suggested a proportion of these could require replacement due to the higher volumetric flows of hydrogen required to supply a given amount of energy. There is significant uncertainty around this issue, and it has been suggested that many of these works could be avoided by various network level solutions, however this could have significant implications for customers. An estimated range of service pipe replacements for South Wales is 521,000 to 526,000 across all three scenarios.

[20] NIA 275 H21 – Hydrogen Ready Services (https://h21.green/app/uploads/2021/02/NIA-275-H21-Hydrogen-Ready-Services-Final-Version.pdf) [Accessed 24/03/2022)

Medium, intermediate and high-pressure networks

Each scenario explored has an associated 'Bill of Quantities', indicating the quantity of infrastructure needed, summarised in Figure 103. This is the same for all three scenarios in South Wales, as discussed in Section 7. Values are given as a percentage of the length of currently existing network for each respective pressure tiers – these are of 882km for the HP network, 379km for the IP network, and 937km of MP network.

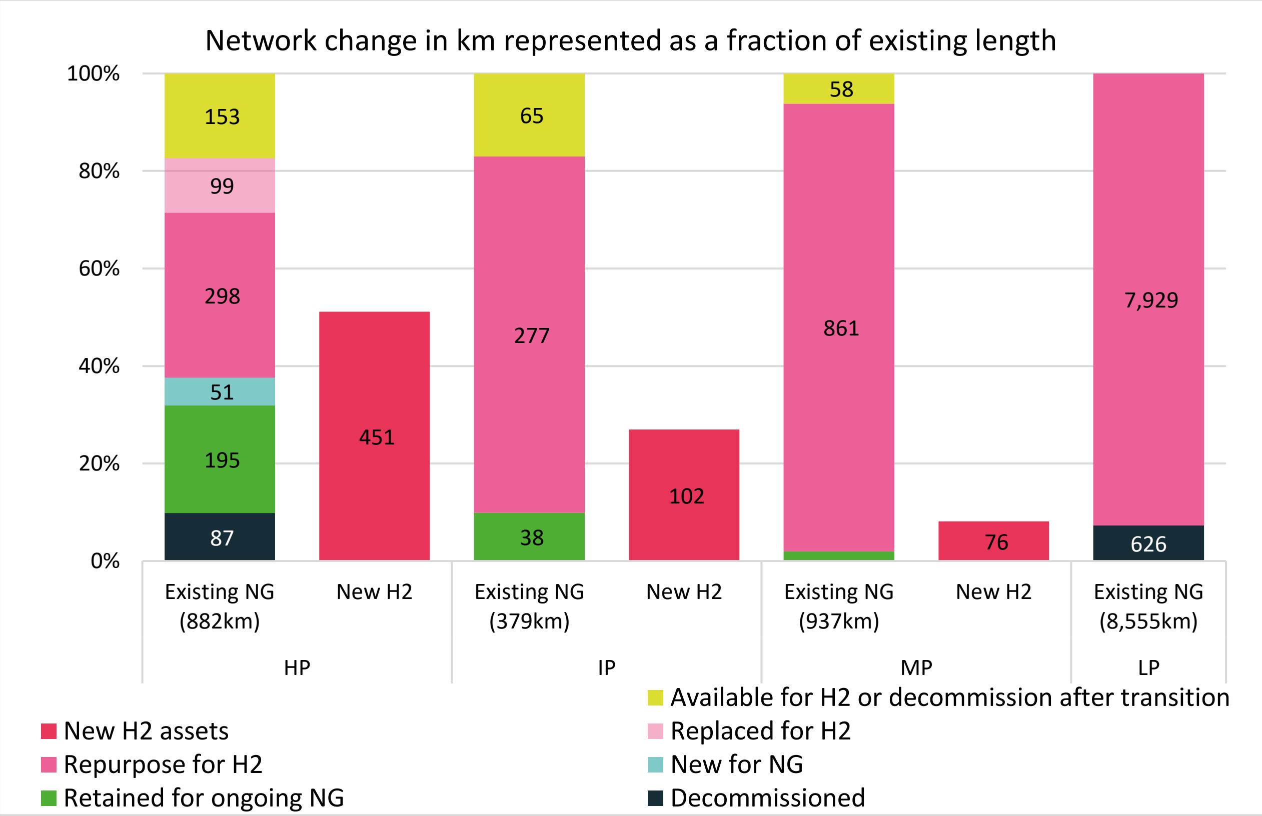


Figure 103: Network changes as a percentage of existing pressure tier length

In modelling the transition of networks from the network as it is today to one indicative of that required to serve the 2050 scenarios, the method re-purposes as much of the existing natural gas network for hydrogen service as possible. This was done whilst considering the need to maintain a natural gas supply through the transition and practical switching constraints of connections dependent on a natural gas supply to one receiving hydrogen. The result is an increased quantity of repurposing that is considered generous and reduced amount of new hydrogen. Transition of gas networks is recognised as a highly complex process and further analysis is required to fully understand the influencing factors to inform decisions. The detail of the modelling logic is provided in section 7.

Medium Pressure

Only around 6% of the length of the currently existing MP network is indicated as continuing to serve natural gas in 2050. The assets used for this purpose are the last few tens of kilometers between higher pressure tier pipelines, and industrial demand sites. In addition, most of these sites represent relatively high demand, hence in some cases are directly connected to the IP network.

A typical section of MP in South Wales provides one of many routes for gas to flow into a connected region of LP gas network. This explains the high percentage (92%) of existing MP pipe which could be "repurposed for hydrogen service", and the correspondingly low quantity of new hydrogen MP assets. This redundancy may allow for the repurposing of these existing assets by sector during the transition, negating the need for new hydrogen assets along similar routes (see section 4 for further details).

Intermediate Pressure

The IP network shows a similar pattern as MP, however with different proportions: around 73% of the network repurposed to hydrogen, 10% retained for ongoing demand and an additional 17% retained for transition. As a result, the new hydrogen IP assets to be built for hydrogen supply in 2050 amount to around 27% of the length of the existing network. This similarity with MP gas network changes is explained by a combination of some IP gas network playing a similar role to MP gas network in some urban areas of South Wales, and to long stretches of existing IP pipes serving only small numbers of non-industrial connections in more rural areas. In the latter case, further detailed flow modelling could help refine the quantity of IP pipe required to enable the transition.

***High* Pressure**

Close to 30% of the HP gas network in South Wales consists of vintage pipelines[21], which are likely to be replaced or decommissioned by 2050, providing an opportunity under these scenarios to ensure new pipelines are ready for a transition to hydrogen. Around 6% of the network length would need to be replaced by new natural gas assets to supply ongoing demand,11% replaced by new pipes supplying hydrogen, and 10% could be directly decommissioned (not needed for ongoing demand nor for transition). Around 22% of the existing HP gas network could be retained to supply natural gas demand in 2050, and an additional 17% for transition requirements.

As mentioned earlier, this last figure is due to linear sections of the network being the only route supplying large numbers of connections, which constrain the transition logistics, as explained in section 4. By 2050, once the transition is complete, this 17% could be made available for reinforcement or storage in the hydrogen network, or alternatively decommissioned.

This results in 34% of the HP gas network that could be repurposed for hydrogen supply, leading to the need for completely new hydrogen pipes with a total length equivalent to more than 50% of the existing network length.

[21] 'Vintage pipelines' refers to pipelines, and pipeline sections, commissioned prior to the early 1970s.

22.5. CONCEPTUAL PLAN

The Conceptual Sub Regional Pull Outs are based on engineering analysis which considers the implications of the scenarios for natural gas and hydrogen infrastructure. This provides a basis to understand the decisions which are required around investment in network infrastructure to support decarbonisation and, provide an indicative illustration of the uptake of conversion of Domestic and Commercial meters to hydrogen between 2020 and 2050, across the three scenarios.

22.5.1. INSIGHTS SUMMARY – SOUTH WALES

- Given the proximity of LNG importation terminals into Milford Haven and the location of major industries. South Wales is likely to be a potential exporter of hydrogen to England both within the WWU supply area to the South West and to the Midlands.
- Potential to Repurpose: The majority of the LTS system in South Wales (Figure 56) was constructed from pipe material strength grade of X52 and below. These pipe materials are suited to the transportation of hydrogen however, where pipelines have been constructed of higher strength grade then further work may be required to be undertaken prior to conversion to confirm their suitability. There are also a number of sections of the LTS network in South Wales which are over fifty years old and may potentially reach the end of the pipelines useable life shortly. Some of these older pipelines may also have been used for Towns Gas service, which can also suffer from further degradation due to the effect of hydrogen on the pipe wall. Where these pipelines are to be replaced then it is recommended that they are replaced with pipelines suitably sized and with a pipe material grade which suitable for hydrogen service.
- For all three scenarios in Wales approximately 91-92% (Section 7 ESC) of the Domestic and Commercial gas meters are estimated to be retained in 2050.

Table 24. South Wales Meters Converted per 5 Year Cycle

South Wales	Number of Meters Converted per 5 Year Cycle						
	2020	2025	2030	2035	2040	2045	2050
High Electrification	0	0	0	1283	2899	431	0
Balanced	0	0	721	511	2867	110	0
High Hydrogen	0	0	679	489	2903	176	0

It can be seen from Table 24 that under the Balanced and High Hydrogen scenarios conversion starts circa 2030, while the High Electrification scenario starts approximately 5 years later. The workforce size requirements to undertake conversion will be similar under all scenarios. Circa 2040 is the peak year for conversion, where the conversion rate is slightly above the recommended number of 2500 per week.

- Due in part to the high retention of the Domestic and Commercial customer base, all three scenarios in South Wales will require similar levels of new pipeline infrastructure to enable conversion to hydrogen. In total approximately 377 km of new high pressure LTS hydrogen pipeline would be required in South Wales by 2045. Also, an additional 75 km of new natural gas pipeline would be required to either feed natural gas to hydrogen production facilities or provide cross connections within the existing network during conversion.

Table 25. South Wales KM of New Hydrogen Pipeline per 5 Year Cycle

South Wales	KM of New Hydrogen Pipeline per 5 Year Cycle						
	2020	2025	2030	2035	2040	2045	2050
High Electrification Scenario	0	0	0	237.8	139.0	0	0
Balanced & High Hydrogen Scenarios	0	0	76.2	161.6	72.9	66.1	0

Table 25 details an indicative level of the length of new hydrogen pipeline required in a particular 5 year cycle.

22.5.2. BALANCED (BAL)

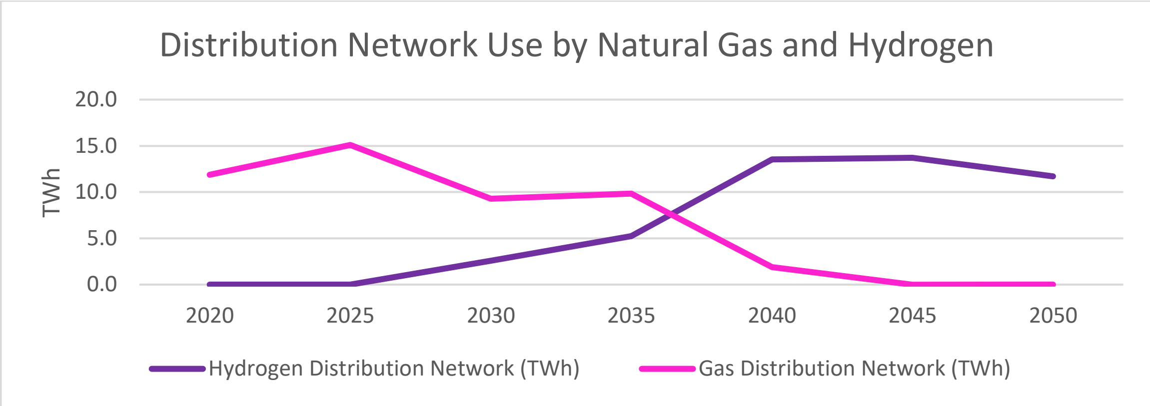
Table 18 shows the forecast hydrogen production and, distribution network consumption of natural gas and hydrogen for the Balanced (BAL) WWU scenario modelled in ESME in Wales. It can be seen that Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Initially hydrogen is supplied to industrial users and starts to be supplied to the distribution system from 2030 with the system supplying the maximum predicted hydrogen demand in 2045. Before consumption drops away towards 2050. Conversion of the Distribution Network is completed shortly after 2040.

Table 26. Wales Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

Wales	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.8	1.2	5.9	11.3	47.8	42.2	33.4
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	2.6	5.2	13.5	13.7	11.7
Natural Gas Consumption from Distribution Network (TWh)	11.9	15.1	9.3	9.8	1.9	0.0	0.0

Figure 104 Wales Distribution Network Use by Natural Gas and Hydrogen – Balanced



As detailed in Section 10, a small number of larger emitters dominate present industrial emissions in South Wales, with the top three industrial emitters contributing by up to 80% of the total industrial emissions. The decisions taken by the major emitters to decarbonise their emissions will have a significant impact on the energy transition solutions deployed in the region. Figure 105 shows the NAEI Sector and Emission Tonnage for the major emitters of carbon dioxide in South Wales.

Figure 105 South Wales - NAEI Large Emitters By Sector and Emissions Tonnage

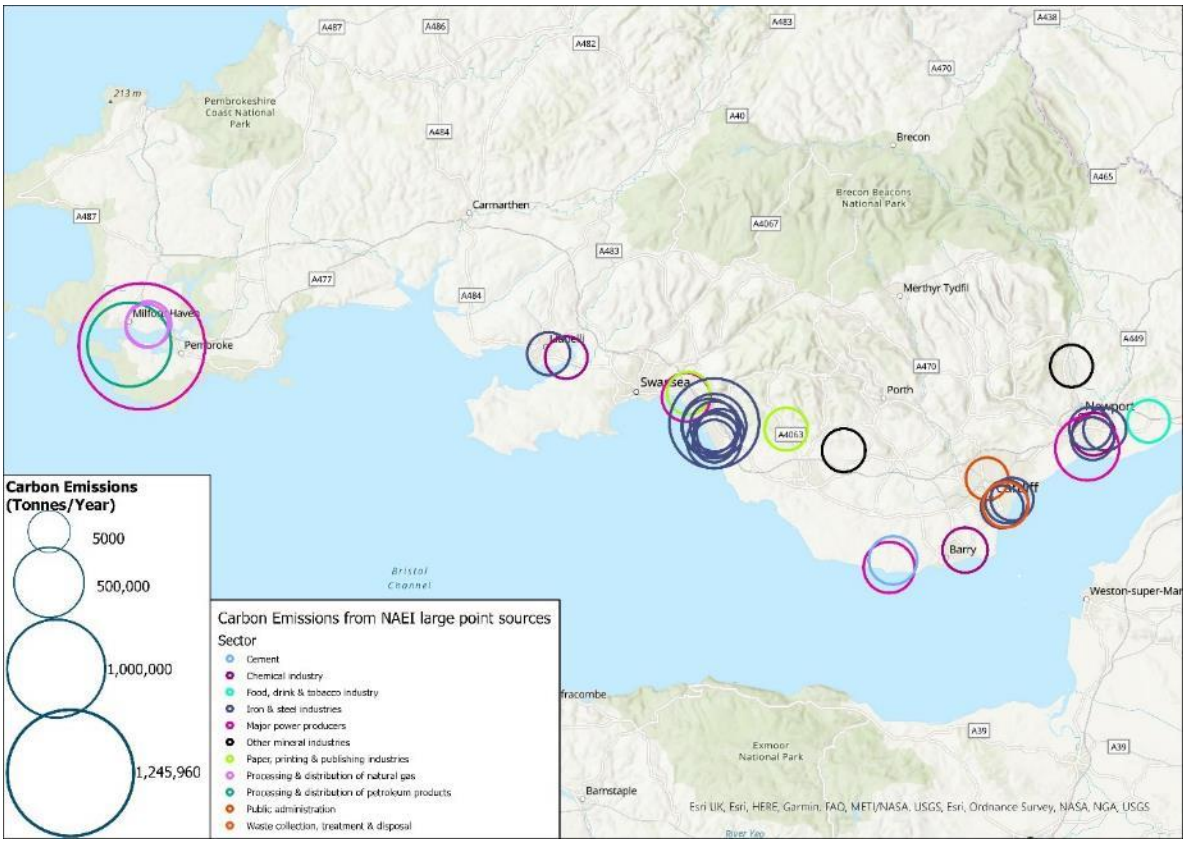


Table 27 shows the forecast number of South Wales meter points that require converting from natural gas and hydrogen on the distribution network for the Balanced (BAL) scenario.

Table 27. South Wales Meters Converted per 5 Year Cycle – Balanced

South Wales	Number of Meters Converted per 5 Year Cycle – Balanced						
	2020	2025	2030	2035	2040	2045	2050
Dowlais	0	0	0	78158	387523	0	0
Dyffryn	0	0	144209	24035	32416	0	0
Gilwern	0	0	0	0	153545	21964	0
Total	0	0	144209	102193	573485	21964	0
Meters Converting per Week (40 Wks/Year)	0	0	721	511	2867	110	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period i.e. over 40 weeks per year (March to November).

In 2040 the number of meters requiring conversion is higher than the recommended figure of 2500 from the HYDROGEN1 Project, therefore either an additional conversion team will be required, or a number of meters scheduled for 2040 would have to be push back into 2045.

Figure 106 2030 Balanced - Domestic and Commercial Meters

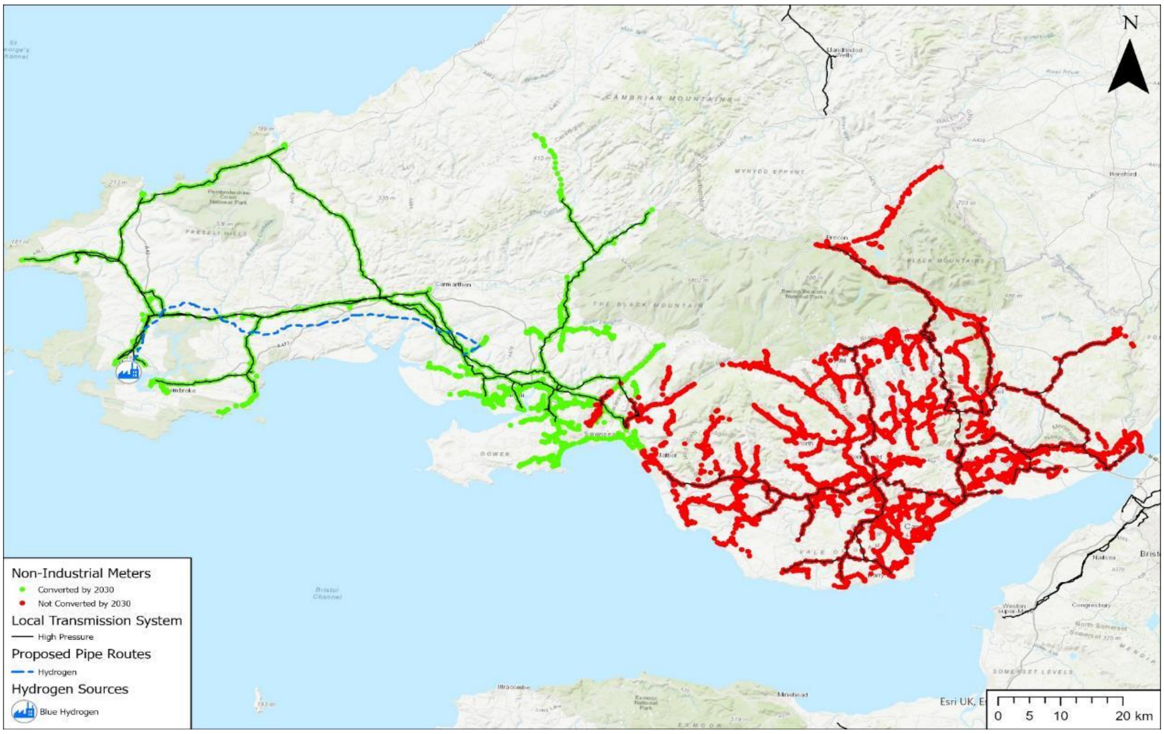


Figure 107 2035 Balanced - Domestic and Commercial Meters

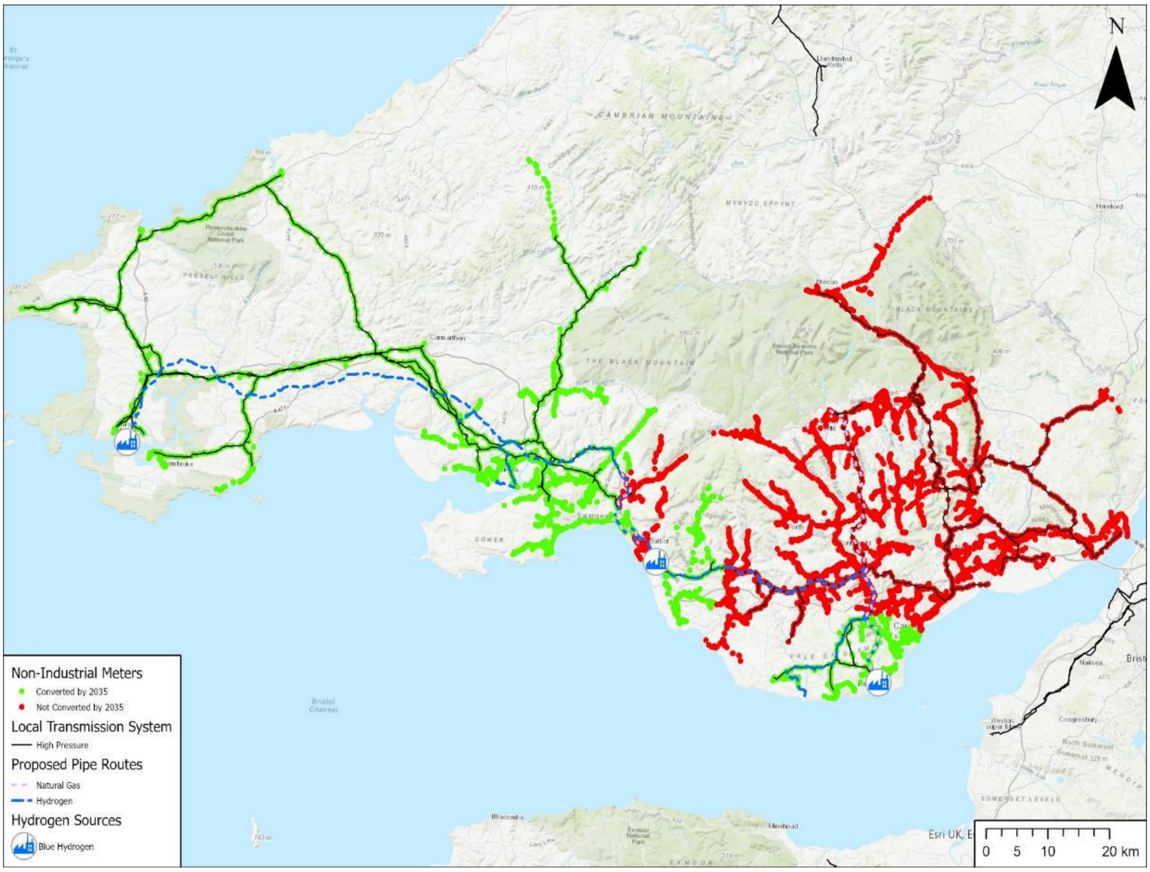


Figure 108 2040 Balanced - Domestic and Commercial Meters

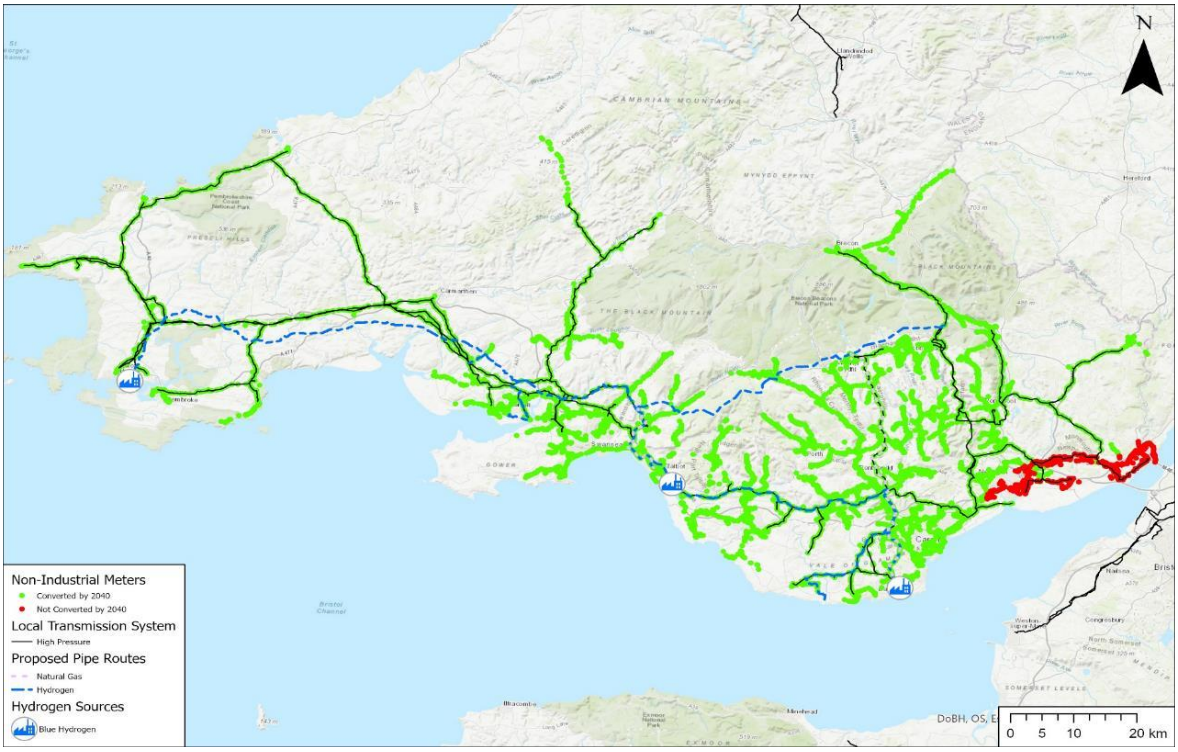


Figure 109 2045 – 2050 Balanced - Domestic and Commercial Meters

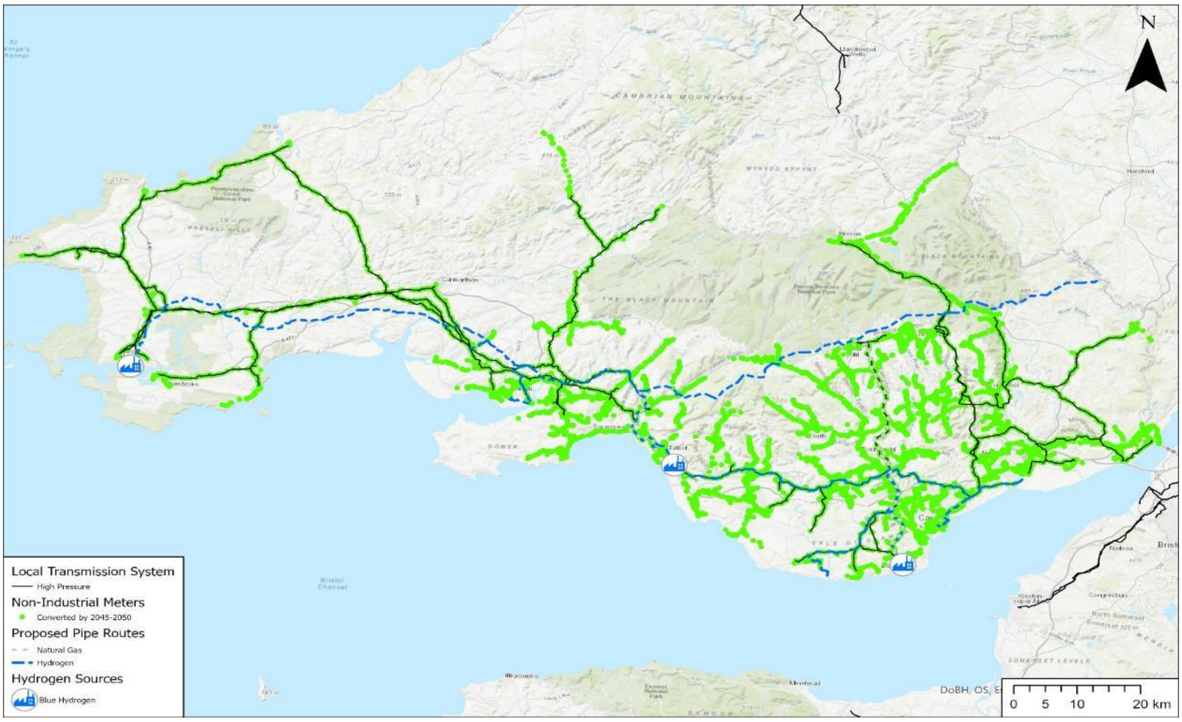
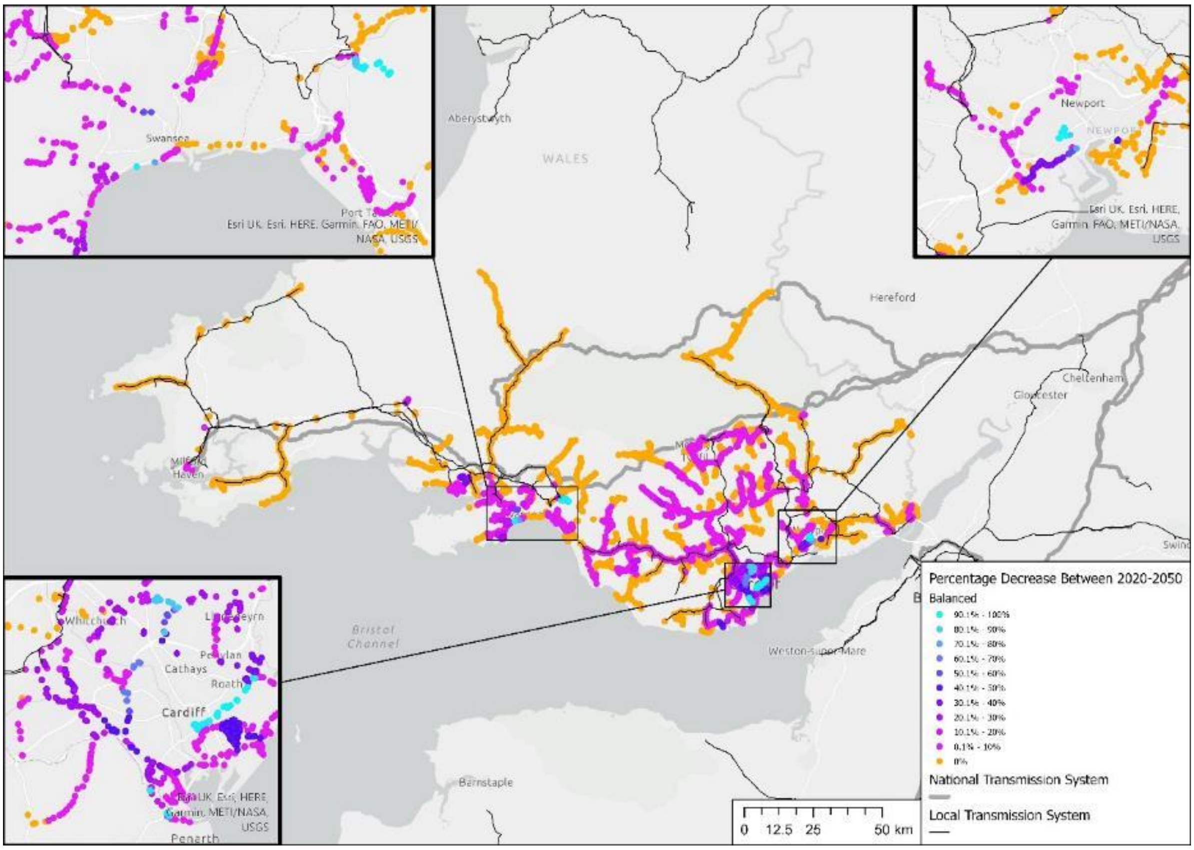


Figure 110 % Change in the Domestic and Commercial Meters – Balanced in 2050



Under the Balanced scenario there will be an approximate 8% reduction in the number of non dependent meters. Figure 110 details the areas where there is predicted to be a fall in the number of customers on the gas system. A higher proportion of meters are lost in the centre of a number of the major conurbations, where district heating takes over as the source of domestic heat load.

22.5.3. COMPARISON OF THE THREE SCENARIOS

According to the ESME Whole System Overview (Section 0), for all three scenarios hydrogen production ramps up and peaks in similar timescales. Production of hydrogen and hydrogen consumption from the distribution network are broadly similar for High hydrogen (110% of balanced). However, in the High electrification case, production of hydrogen and hydrogen consumption from the distribution network is lower than the Balanced scenario (75% of Balanced). As the number of domestic meters is broadly the same across all three scenarios, this would indicate that individual consumption is the primary variable rather than the number of supply points. As can be seen from Figure 14.48, there are falls in the number of domestic meters in the major conurbations and this is broadly reflected across all three scenarios with a slightly greater reduction in the numbers of meters (9% v 8%) in the High Electrification scenario.

The quantity of new pipeline required will be similar across all three scenarios, due in part to the requirements for the system to be able to supply peak demand. However, for the High Electrification case, pipeline diameters may be slightly smaller than those required for the High Hydrogen and Balanced scenarios.

Details of the Conceptual Plan analysis of Electrification and High Hydrogen scenarios can be found in Section E.

SECTION D -
SUB-REGIONAL ANALYSIS

GLOUCESTERSHIRE, NORTH SOMERSET, SOMERSET, WECA AND WILTSHIRE PULL OUT*

* This sub-regional analysis should be read in conjunction with Parts A, B and C of the report

23. SUB-REGIONAL NETWORK ANALYSIS – GLOUCESTERSHIRE, NORTH SOMERSET, SOMERSET, WECA AND WILTSHIRE

This sub-section of the report provides further interpretation for the sub-region of Gloucestershire, North Somerset, Somerset, West of England Combined Authority (WECA) and Wiltshire of the whole systems modelling undertaken by the Energy Systems Catapult (ESC's) in Sections 6 and 7 and the engineering analysis undertaken by Costain in Sections 10 to 16 of the main report. The Gloucestershire, North Somerset, Somerset, WECA and Wiltshire analysis is structured in a similar way to the earlier sections of the report, with the implications of ESC's modelling set out in a Strategic Plan sub-section (see section 23.2) and the Costain engineering analysis set out in a Conceptual Plan section (see section 23.5). In advance of both these sub-sections, an overview of the key features of North Wales is provided (see Section 23.1).

23.1. OVERVIEW OF GLOUCESTERSHIRE, NORTH SOMERSET, SOMERSET, WECA AND WILTSHIRE

The modelling used as the basis for the sub-regions analysed in this section is applied directly to the geographical area of WECA in its entirety, almost all of the County of Somerset, almost all of Gloucestershire, the entirety of Swindon and the majority of Wiltshire, as well as small parts of West Berkshire, Oxfordshire, Warwickshire, Worcestershire, and Herefordshire. In the analysis presented here, this area is split into the five sub-regions shown (shaded red) on the map (Figure 111).

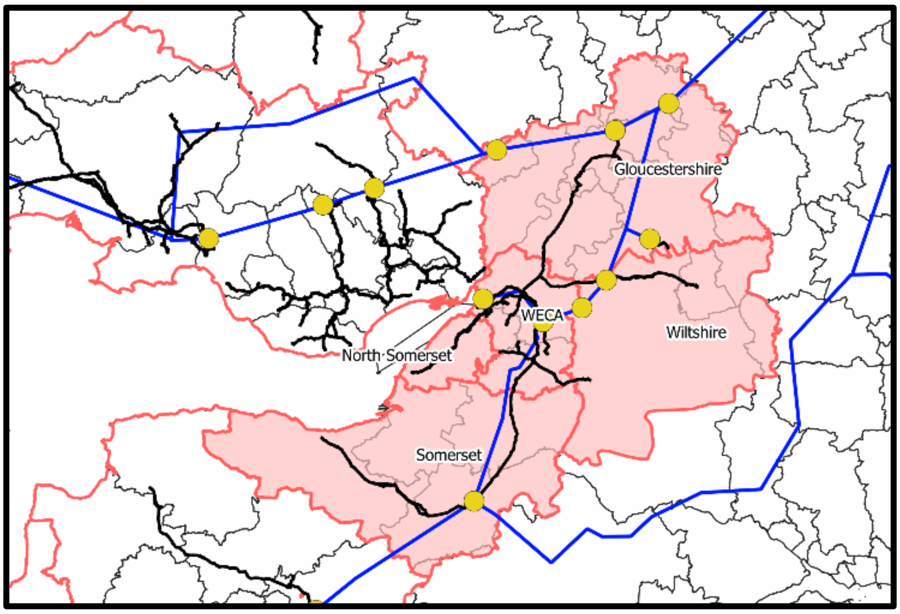


Figure 111: The five sub-regions covered by this pull-out section. The black lines show WWU's high-pressure (HP) network. The approximate route of the national transmission system (NTS) gas pipelines is shown in blue. Yellow circles represent 'offtakes' where gas flows from the NTS to the HP network.

Existing local natural gas infrastructure in the regions discussed is supplied by the National Transmission (NTS) pipelines running north to south from Gloucestershire and entering the Somerset sub-region in the south-east. Local gas distribution network infrastructure serves connections in urban, sub-urban and rural areas across the region. The large urban areas of Cheltenham, Gloucester, Bristol, Bath and Swindon, Weston Super-Mare and Taunton have the most interconnected gas distribution networks across the regions. Large rural areas are served in Gloucestershire, Wiltshire and Somerset, where linear network configuration is more common.

23.2. KEY INSIGHTS

Analysis undertaken in the Regional Decarbonisation Pathways project has developed a number of key insights for the development of a Net Zero energy system in Gloucestershire, North Somerset, Somerset, WECA and Wiltshire.

ESC's Strategic Plan (detailed in sections 23.3 to 23.4) found that:

- A high proportion of domestic and business gas network connections are required to be retained under all of the scenarios analysed, driven by the significant uptake of hybrid heating systems and standalone hydrogen boilers. The way the gas grid is used and the volume of hydrogen flowing through it is likely to be very different.
- Disconnections from the mains gas for heating are driven by switching to district heating networks. District heat is deployed in the most densely built-up areas where it is most economical, and so disconnections from mains gas are concentrated in such areas, too.
- Across all three scenarios, the quantity of network infrastructure required to serve the retained natural gas and new hydrogen demands in Gloucestershire, North Somerset, Somerset, WECA and Wiltshire are the same, though the volume they will supply varies. There is extensive opportunity to use existing infrastructure to serve these demands: both the low and medium pressure networks indicate a high proportion of repurposing.

Costain's Conceptual Plan (detailed in section 23.5) found that:

- Although a major hydrogen producing region the WECA, Gloucester, Wiltshire, And Somerset area is likely to still be a net importer of hydrogen. Probably from the South Wales area. There is the potential for the development of "blue" hydrogen production in Avonmouth due to the availability of CCS shipping and natural gas infrastructure. There are also opportunities for nuclear power and hydrogen cogeneration in all scenarios, this capacity is likely to be concentrated at the Hinkley site.
- There are a small number of larger emitters who dominate. The decisions taken by the major emitters to decarbonise their emissions will have a significant impact on the energy transition solutions deployed in the region, and the timing of the infrastructure developments required.

23.3. STRATEGIC PLAN ANALYSIS (WHOLE SYSTEM MODELLING)

ESC's Strategic Plan analysis has been developed to provide insights into the possible future role of the gas network in Gloucestershire, North Somerset, Somerset, the WECA and Wiltshire. It uses, as its basis, three whole system energy scenarios developed in collaboration with Wales and West Utilities and Costain, to explore different futures for hydrogen use in the South-West of England and Wales. These three UK-wide, whole energy system scenarios are described in Section 5.5 of the main report and are:

- Consistent with the UK's 2050 Net Zero and interim, statutory carbon targets.
- Identify three levels of hydrogen use for the South-West of England as part of the wider UK energy system.

This section should be read in conjunction with earlier parts of this document, to gain a full understanding for the context for the scenarios and the pathway for the broader whole energy system in the South West of England, within the wider context of the rest-of the UK energy transition. These three scenarios provide the basis for a strong role for hydrogen. Other scenarios will see less use and some more.

This is the first-time whole system energy modelling has been linked to sub-regional strategic network modelling analysis, to start to understand the potential shape and nature of the Wales and West Utilities (WWU) gas grid in 2050. This is network analysis and insights, based upon whole system modelling and there will be practicalities and engineering constraints faced by hydrogen network conversion. These considerations are further assessed in the sub-regional Conceptual Plans produced by Costain in sections 23.5 below.

This analysis does not replace the need for detailed network modelling and engineering-based feasibility and design but are intended as the basis for analysis and discussion.

23.4. STRATEGIC PLAN INSIGHTS

The key insights for gas and hydrogen networks in Gloucestershire, North Somerset, Somerset, West of England Combined Authority (WECA) and Wiltshire, identified through this Strategic Plan analysis are:

- A high proportion of domestic and business gas network connections are retained in all three scenarios, driven by the significant uptake of hybrid heating systems (i.e., heat pumps providing baseload heat and hydrogen boilers providing peaking) and standalone hydrogen boilers. Despite this similarity, the proportion of these systems which are hybrid rather than standalone boilers, is significantly higher in the ELE scenario than in BAL and HYD, and the annual hydrogen consumption is correspondingly lower, as a greater proportion of baseline heat demand is met by electricity.
  District heat is deployed in the most densely built-up areas where it is most economical, and so disconnections from mains gas are concentrated in such areas, too., leading to significant variation in the percentage of non-industrial connections retained across the sub-regions covered in this pull-out: WECA has the most disconnections (66% retained by 2050) and Wiltshire the least (95% retained by 2050).
- Some of the areas covered in this pull-out exhibit relatively large variation across scenarios in the number of non-industrial meters disconnected (38% in ELE vs. 31% in HYD) and in the length of LP network decommissioned when compared to those in other sub-regions. As in other areas, there is greater variation the annual hydrogen *consumption* through these

connections due to greater use of hybrid heat pump / boiler systems in ELE than other scenarios. However, the changes required in the network at medium pressure (MP) and above by 2050 (lengths of new/repurposed pipe etc.) are still virtually the same across scenarios. In particular, in the dense urban areas where disconnections are concentrated there are rarely any connections which depend exclusively on a single branch of MP network for gas supply, and so it is already possible to avoid the need for entirely new hydrogen network to support the piece-meal transition of these areas, even if there are no disconnections.

- Large scale nuclear cogeneration of power and hydrogen appears in the South West region in all three scenarios and in all scenarios this capacity is entirely concentrated at the Hinkley and Oldbury sites (in Somerset and WECA) for the purposes of our modelling. All three scenarios feature "blue" hydrogen production in the South West region, and Avonmouth is the main site in the South West to which this is allocated in our scenarios, on the basis of the availability of CCS shipping and natural gas infrastructure.
- Each scenario explored the quantity of network infrastructure required to serve the retained natural gas and new hydrogen demands. The changes needed across all the areas covered in the pull-out are the same for all three scenarios. A potential opportunity to re-purpose existing natural pipe assets for service in a hydrogen network has been identified.
  Both the low and medium pressure networks indicate a high proportion of repurposing, the intermediate and high-pressure tiers offer a less opportunity of existing pipelines, but sill material for IP. The respective figures for each area and pressure tier is provided in the table below. This insight is indicative and should be considered in the context of this modelling. A complete view of the feasibility of repurposing these assets will become available once industry technical, safety and network transition studies are completed.

Sub Region	Low Pressure	Medium Pressure	Intermediate Pressure	High Pressure
Gloucestershire	88% (2507km)	87% (475km)	62% (112km)	0% (0km)
North Somerset	86% (685km)	94% (131km)	66% (14km)	27% (14km)
Somerset	88% (1589km)	85% (552km)	53% (17km)	19% (22km)
WECA	66% (1969km)	85% (306km)	71% (17km)	42% (78km)
Wiltshire	89% (1759km)	84% (433km)	74% (94km)	36% (21km)

Table 28 – Gloucestershire, North Somerset, Somerset, WECA AND Wiltshire, sub-regions potential pipe and pipeline re-purposing.

23.4.1. SCENARIO ANALYSIS

The three whole system scenarios used as the basis of the modelling are the High Electrification (ELE), Balanced (BAL) and High Hydrogen (HYD) which are distinguished by several different assumptions summarised in section 6.1.2. The major distinguishing features of the scenarios (i.e., the results of the modelling) are their relative use of the type of heating system present in 2050:

- The ELE scenario sees a prevalence of electrical systems (heat pumps, electric resistive heaters) to provide heat in residential and non-domestic buildings, and hydrogen can operate in peak demand periods but with a limited load factor. This scenario favours hybrid electric-hydrogen[22] systems as a result.

[22] Hybrid systems use heat pumps to provide baseload heating and hydrogen boilers to provide peaking.

- The BAL scenario, the amount of heat supplied by heat pumps is restricted and hydrogen and electrical systems are set to be equal, reflecting a world where no strong policy is supporting the deployment of heat pumps.
- The HYD scenario assumes that most heat is supplied by hydrogen-based heating systems (hybrid electric-hydrogen systems, hydrogen boilers) and policy supports deployment of hydrogen technology.

Further detail is provided in section 5.5 of the main report.

23.4.1.1. 2050 GASEOUS FUEL SUPPLY, PRODUCTION AND TRANSMISSION

Across the three scenarios explored, both hydrogen and gas have a role within a Net Zero energy system in Gloucestershire, Somerset and WECA in 2050. North Somerset and Wiltshire, both have hydrogen demand, but do not have any retained natural gas demand in 2050. Natural gas is utilised in industry and for hydrogen production, but a further explanation of its continued use in 2050 is provided in section 6.2.6.

Given that all three scenarios have retained natural gas demand, an NTS is assumed to be available to the extent that it will meet retained natural gas demands in 2050 in Gloucestershire, Somerset and WECA. Specific changes to national transmission assets have not been assessed as part of this analysis. However, retained distribution networks indicate that all of the NTS offtakes across the sub-regions would be needed to supply natural gas in 2050 for each scenario explored. Although North Somerset and Wiltshire do not have retained natural gas demand in 2050, retention of NTS assets is required to supply the adjacent sub regions.

Within the sub regions with retained natural gas demands, some of this is used by industry in 2050 across all three scenarios. However, most natural gas consumed in WECA is used as a feedstock for 'blue' hydrogen production[23]. There is no blue hydrogen produced in Gloucestershire, North Somerset, or Wiltshire. WECA benefits from, proximity to industrial demand, population centre of Bristol, the existing NTS corridor and port of Avonmouth for shipping of captured carbon to potential storage sites located off the coast of the North of England.

Blue hydrogen production is one of the drivers for retained natural gas networks in the scenarios explored. This means that if the case for blue hydrogen were to change through influencing factors such as cost of natural gas, a different network requirement may emerge. This could subsequently have an impact on the economics of hydrogen networks and development through the transition.

In addition to the blue hydrogen, hydrogen production by electrolysers using nuclear power 'Nuclear Power Hydrogen Cogen' described in section 6.2.2, is located in the north of the WECA region and Somerset. These have been speculatively located based on the use of facilities in the vicinity of existing nuclear sites, providing this study with an indication of how the technology could be deployed and interact with hydrogen networks. Further economic and technical studies are required to understand the feasibility of this technology.

[23] 'Blue' meaning that the production process yields carbon dioxide which is captured and stored.

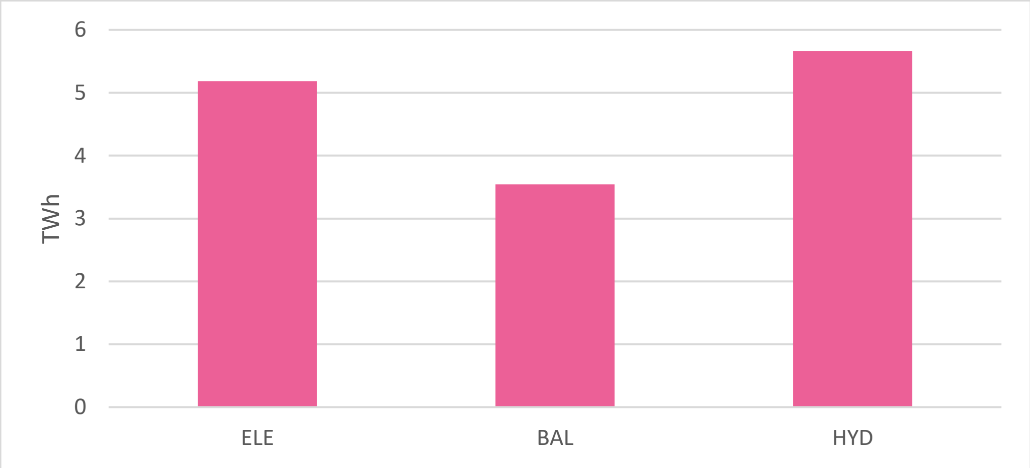


Figure 112: Natural gas consumption from blue hydrogen production in 2050 by scenario (TWh). Only WECA contains hydrogen production that uses natural gas as a feedstock ('blue' hydrogen production).

In addition to the blue hydrogen, hydrogen production by electrolysers using nuclear power 'Nuclear Power Hydrogen Cogen' described in section 6.2.2, is located in the north of the WECA region and Somerset. These have been speculatively located based on the use of facilities in the vicinity of existing nuclear sites, providing this study with an indication of how the technology could be deployed and interact with hydrogen networks. Further economic and technical studies are required to understand the feasibility of this technology.

Figure 113: Annual hydrogen production in WECA (top) and Somerset (Ex. North) (bottom) in 2050 by scenario.

Analysis has shown that WECA and Somerset have the more suitable locations for hydrogen production, resulting in no hydrogen production in North Somerset, Gloucestershire or Wiltshire.

Across all the scenarios explored in this project, hydrogen has a role within each of the five sub-regions of discussed in this pull-out. A hydrogen transmission system is assumed to be the primary source of hydrogen to the local distribution system, supplied through offtakes in the vicinity of existing natural gas offtakes. Hydrogen production is assumed to feed into the respective hydrogen network pressure tiers and could play a role supplying demand in the vicinity of the locations.

23.4.1.2. GASEOUS FUEL CONSUMPTION

Industrial

All the industries located in Wiltshire and North Somerset are within sectors suitable for decarbonisation through hydrogen, and therefore there is no remaining industrial natural gas demand in these sub regions in any of the scenarios in 2050. The detail of the assumptions used to obtain remaining industrial natural gas demand is given in section 7.

Gloucestershire, Somerset and WECA contain major industrial sites in two of the four industrial sectors considered to have ongoing natural gas demand in 2050, as described in section 4: paper mills (in all three) and chemicals (in Gloucestershire only). These are assumed to all be retained out to 2050, however their continued operation will ultimately be subject to a range of other economic factors, including the future of the energy system.

It is assumed that all sites in other industrial sectors can switch to hydrogen by 2050, supporting wider network transition. Practically the switchover of industrial demands during network transition is likely to be complex, requiring consideration of both local network and stakeholder factors. Additional commercial and engineering analysis is required to identify interdependencies and understand how these can be managed to optimise network transition. Further details of how industrial demand has been modelled is provided in section 7.2.2.

Non-industrial

For the scenarios explored, domestic and commercial gas demand for space heating and hot water is replaced by a combination of hydrogen, electricity, and heat network-based heating solutions. Gas boilers are displaced by hydrogen boilers, hybrid hydrogen heat pumps, heat interface units for heat networks and electric resistive heating. The combination of these is an output of the regional strategic modelling (see section 6.2.12) and depends somewhat on the underlying assumptions informing each scenario.

Typically, in the ELE scenario, the bulk of the heat is supplied by electric heating systems, and hydrogen boilers are limited to backup operation at peak times. The presence of district heating is conditioned by the density of buildings, making it more economical in denser areas where the transportation losses are reduced. The adoption of heat network is the main driver to disconnection from the gas network in 2050.

From a whole system perspective, hybrid boilers are valuable, reducing the capacity and associated cost of heat pumps whilst mitigating the expense of meeting high electricity peak demands and utilising existing infrastructure assets and low-cost storage. However, further work is required to understand the impact of network maintenance costs and the transitional capital costs to realise least cost system designs.

Notable differences identified between the scenarios include a much higher proportion of total heat production throughout the year due to Hydrogen boilers in HYD than in BAL, and in BAL than in ELE. Based on this analysis, switching from mains gas to district heating is the only driver of disconnection of non-industrial meters considered across all three scenarios.

23.4.1.3. CHANGES TO THE GASEOUS DISTRIBUTION NETWORKS

Non-industrial connections and low-pressure networks

Given the relative density of heat demand, WECA has the highest proportion of dwellings connected to district heat networks; over 30% by 2050 across all three scenarios. This then corresponds to a relatively high proportion homes and commercial buildings disconnecting from the gas network; 31-38% across the scenarios. These figures are particularly consistent across the scenarios for WECA since it has a particularly small fraction of dwellings already off the gas network.

The length of low-pressure gas network decommissioned by 2050 is similar across the three scenarios in WECA (26-34%), with least decommissioning in the HYD scenario. The slightly lower relative reduction in LP network length as compared to non-industrial meters is due to the disconnections being concentrated in the dense areas most suitable for district heat. Where the length of LP pipe per connection is lower than average for the sub-region.

These modelling outputs suggests that large volumes of connections and LP network are retained across the scenarios, care is advised when interpreting this insight. The modelling method used is based on a breakdown of a least cost whole energy system for the UK to the sub regions discussed in this section. Resulting in retention of parts of the gaseous network which may be uneconomical in some scenarios. Further technical and economic analysis is required to obtain additional understanding of the interaction between local, regional, and national networks to enable cost optimal system design at each level. The scenarios here have indicated that where volumes of hydrogen reach low levels there could be a requirement to consider economic optimisation by assessment of further options between different levels of geographic granularity.

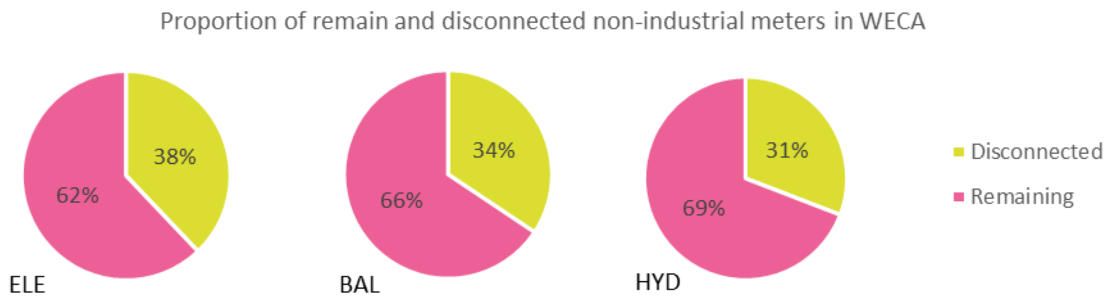


Figure 114 -WECA Non-industrial disconnected and remaining meters (total number: 351,923)

Aside from WECA, all regions have similar levels of LP gas network decommissioning and non-industrial connection removal – with slightly less of each in the HYD scenario.

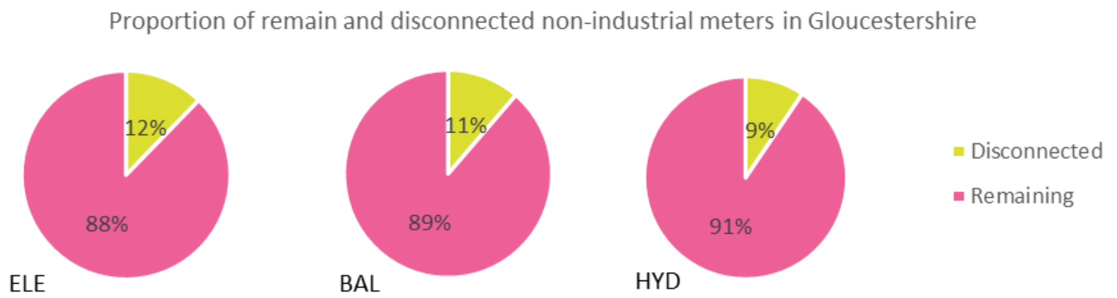


Figure 115 – Gloucestershire Non-industrial disconnected and remaining meters (total number: 258,524)

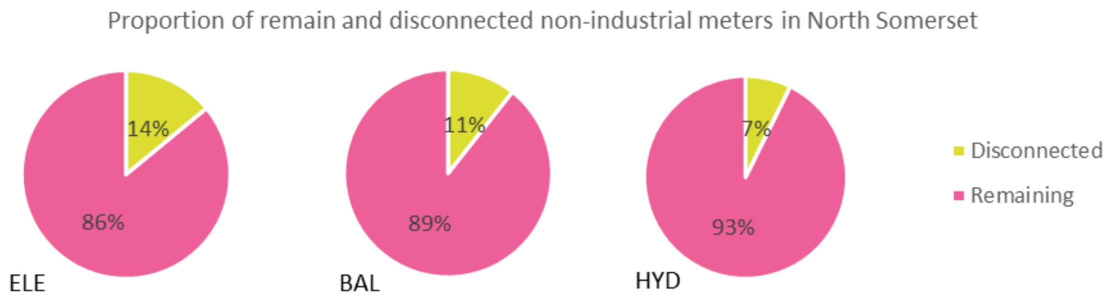


Figure 116 – North Somerset Non-industrial disconnected and remaining meters (total number: 85,265)

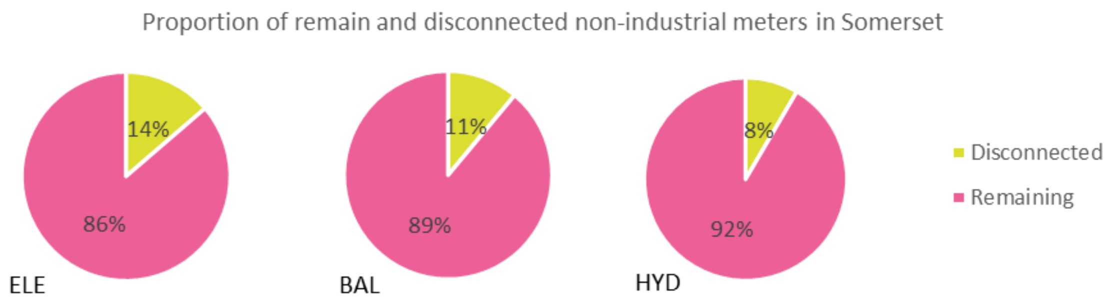


Figure 117 – Somerset Non-industrial disconnected and remaining meters (total number: 176,500)

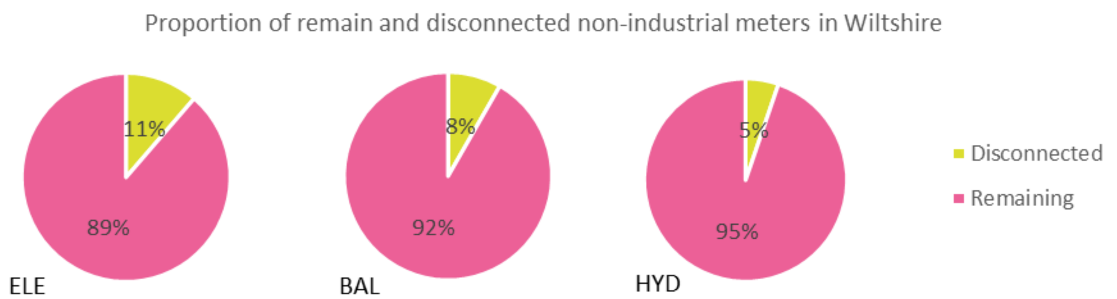


Figure 118 – Wiltshire Non-industrial disconnected and remaining meters (total number: 211,903)

Service pipes link the LP network to individual properties. An H21 project report[24] suggested a proportion of these could require replacement due to the higher volumetric flows of hydrogen required to supply a given amount of energy. There is significant

[24] NIA 275 H21 – Hydrogen Ready Services (https://h21.green/app/uploads/2021/02/NIA-275-H21-Hydrogen-Ready-Services-Final-Version.pdf) [Accessed 24/03/2022)

uncertainty around this issue, and it has been suggested that many of these works could be avoided by various network level solutions, however this could have significant implications for customers. An estimated range of service pipe replacements for the sub regions are provided below:

Sub Region	Lower	Upper
Gloucestershire	142,000	146,000
North Somerset	46,000	49,000
Somerset	95,000	101,000
WECA	137,000	152,000
Wiltshire	117,000	125,000

Table 29: Indicative service pipe replacement volumes

Medium, intermediate and high-pressure networks

Each scenario explored has an associated 'Bill of Quantities', indicating the quantity of infrastructure needed, summarised in the Figure 119 to Figure 123. This is the same for all three scenarios in Gloucestershire, North Somerset, Somerset, WECA and Wiltshire. Values are given as a percentage of the length of currently existing network for each respective pressure tiers. The total network lengths for the 5 sub-regions considered are of 2,104km for the HP network, 384km for the IP network, and 475km of MP network. The lengths of networks of each sub-regions are indicated on their corresponding chart.

In modelling the transition of networks from the network as it is today to one indicative of that required to serve the 2050 scenarios, the method re-purposes as much of the existing natural gas network for hydrogen service as possible. This was done whilst considering the need to maintain a natural gas supply through the transition and practical switching constraints of connections dependent on a natural gas supply to one receiving hydrogen. The result is an increased quantity of repurposing that is considered generous and reduced amount of new hydrogen. Transition of gas networks is recognised as a highly complex process and further analysis is required to fully understand the influencing factors to inform decisions. The detail of the modelling logic is provided in section 7.

Gloucestershire

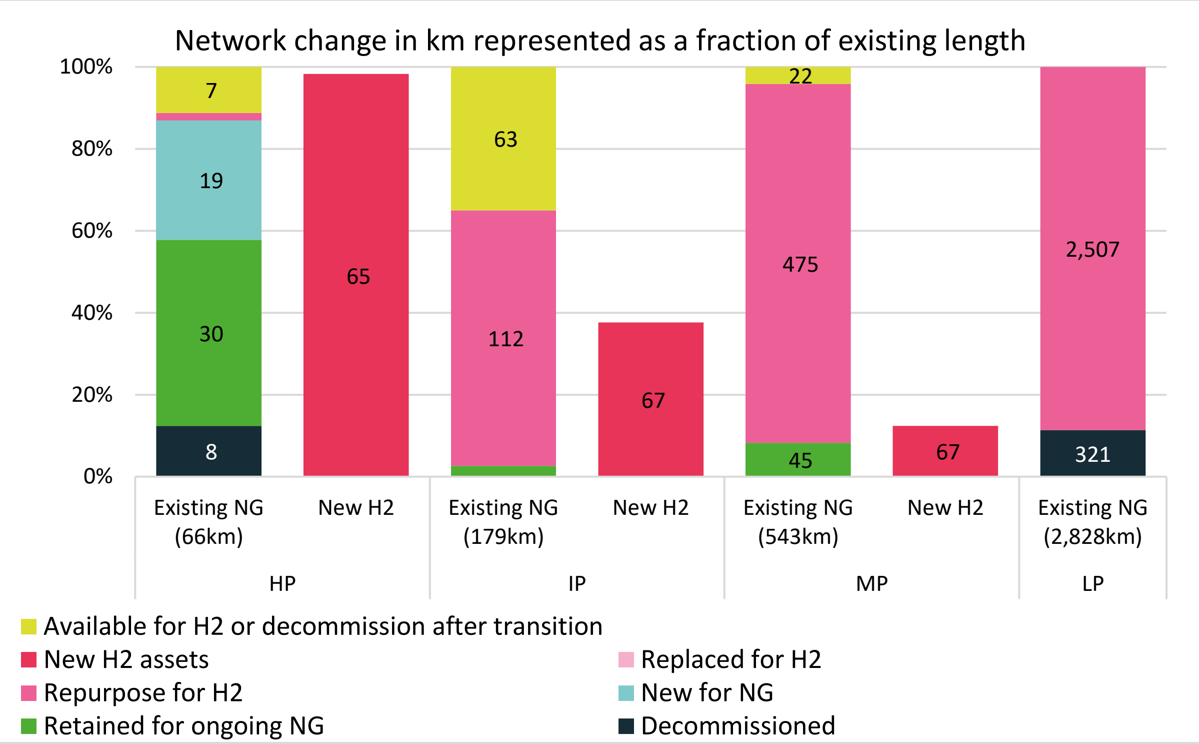


Figure 119: Network changes as a percentage of existing pressure tier length in Gloucestershire

Medium Pressure

The MP network assets needed to be retained on natural gas service in 2050 represent less than 10% of the existing network length. They correspond to the last tens of kilometers between remaining industrial sites and the supply from higher pressure tiers to connect back to the offtake.

Around 4% correspond to network sections on which the number of dependent connections is too high for the transition to hydrogen to happen directly (the threshold for connections is discussed in section 7). These assets are assumed to remain in service for the duration of the transition but will ultimately be made available for reinforcement or decommission (which should be decided by further studies e.g., flow analysis).

The remaining 88% of the MP network could be repurposed to hydrogen by 2050 without further constraints and the necessary new built hydrogen assets correspond to a total of around 12% of the network length.

Intermediate Pressure

More than two thirds of the IP network would have to be retained to allow smooth transition. As for the MP network, such assets are the unique route to supply high numbers of customers, making it a challenge to switch to hydrogen in one go. After the transition, such assets could be made available for reinforcement or decommissioning (the detail of which may be informed by further studies out of the scope of the present project).

A large majority of the remaining two thirds of the IP network could be repurposed directly to hydrogen service, thanks to higher network redundancy, allowing the option of transition, due to low connection numbers.

As a result, new hydrogen assets required to both the transition and further ongoing service, represent just under 40% of the existing network length.

High Pressure

The HP network in Gloucestershire is relatively short and a single offtake (out of three) supplies the 4 industrial sites with remaining natural gas demand in 2050. As a result, the HP network needed for natural gas service in 2050 would correspond to 75% of the existing network. More specifically, 45% of the existing network would remain in service for natural gas demand, while an additional 29% corresponds to vintage assets which would require replacement for ongoing natural gas service. The rest of the vintage assets which are not needed for natural gas service in 2050, 12% of the existing network, would be decommissioned.

An additional 11% of the existing HP network may be needed for the duration of the transition to hydrogen, as it directly supplies high numbers of connections. As a result, less than 3% of the existing HP network could be directly available for transition to hydrogen, leading to the need for entirely new hydrogen assets representing very close to the entire existing HP network.

Wiltshire

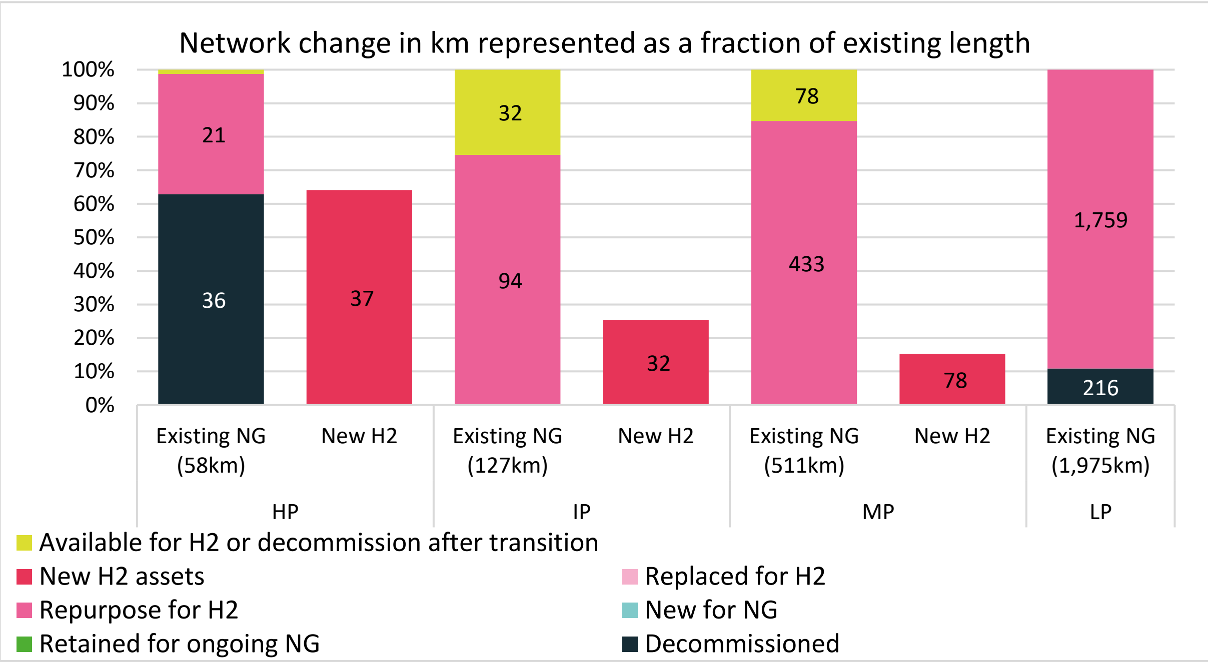


Figure 120: Network changes as a percentage of existing pressure tier length in Wiltshire

Medium and Intermediate Pressure

A quarter of the IP network in Wiltshire could be needed for the transition to hydrogen, due to higher levels of connections dependent on a single section of the network and reduced network redundancy. The same constraints would apply to 15% of the MP network. Such would be made available for reinforcement or decommission, once the transition is complete, by 2050.

For both pressure tiers, the remaining of the existing network could be repurposed to hydrogen, as there is no remaining natural gas demand in Wiltshire 2050. New hydrogen assets 25% of the IP and 15% of the MP network lengths are required. These assets are assumed to be installed in parallel to existing natural gas routes as explained in section 7.

High Pressure

The HP network is mainly split between two outcomes. Two thirds of the assets are 'vintage' and therefore would be decommissioned by 2050. The remaining third will be repurposed for hydrogen by 2050, as no other constraints apply on it. As a result, the new hydrogen pipelines required would correspond to about 64% of the length of the existing networks.

Somerset

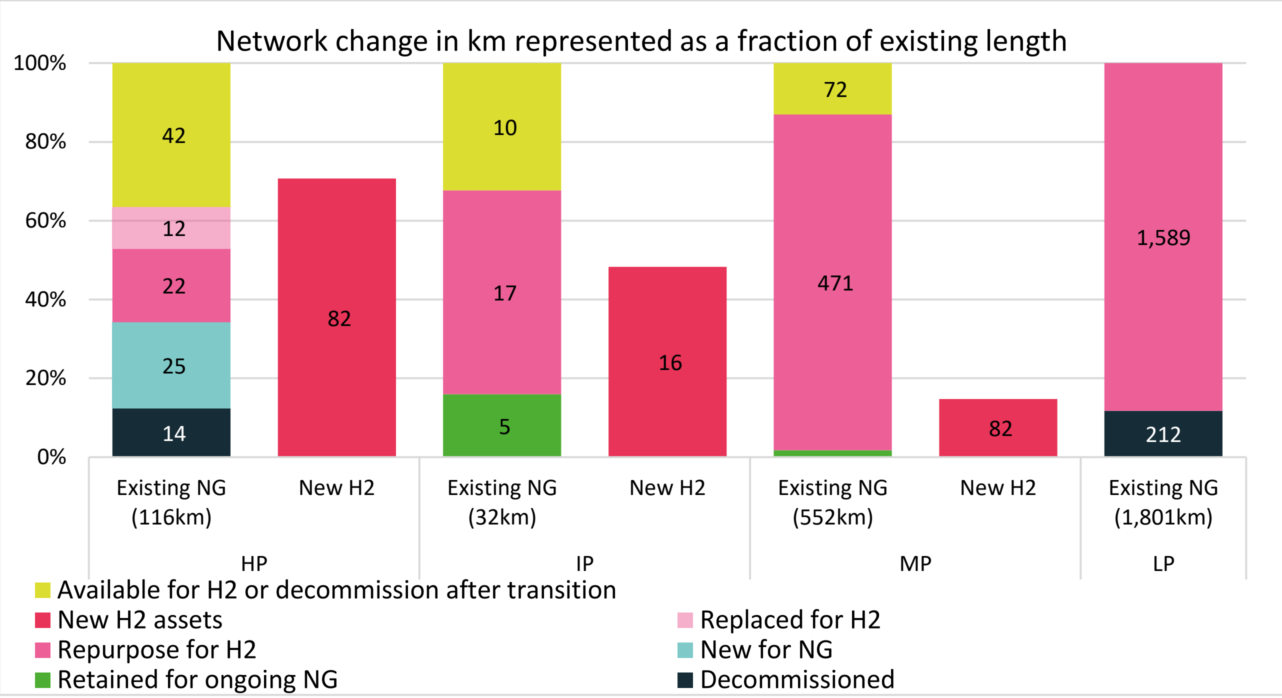


Figure 121: Network changes as a percentage of existing pressure tier length in Somerset

Medium Pressure

In Somerset, assets constrained by transition needs represent 13% of the network length. Such assets are the unique route to a large number of connections, making a straightforward transition challenging (see section 4 for details). Such assets are therefore retained on natural gas until the transition is operated, after which they could either be decommissioned, or used for reinforcement.

The remaining of the MP network (around 85%) could be available for direct repurpose to hydrogen supply, resulting in a need for new hydrogen pipes that would represent around 15% of the existing network length. Only one natural gas demand site remains in 2050, leading to less than 3% of the MP network could be required for ongoing demand, corresponding to the last kilometers to connect it to higher pressure tiers.

Intermediate Pressure

The ongoing industrial need for natural gas would drive the requirement for 16% of the IP network to remain on natural gas service in 2050. An additional 32% of the IP network length would remain on natural gas demand for some time, in order to allow for the transition of zones in which the dependent connection on given pipes is too high. These assets would be made available for reinforcement or decommission by 2050, once the transition is operated.

The remaining half of the IP network could be directly repurposed to hyd234ogen service, which would mean that the need for entirely new hydrogen pipes would be equivalent to just under half of the existing IP network length.

High Pressure

Across all three scenarios, 44% of the HP pipelines are considered 'vintage' and would need replacement to serve the remaining ongoing natural gas demand at industrial sites, 22% would be replaced by new natural gas assets to ensure ongoing supply, 11% would be replaced for hydrogen service, and the last 12% decommissioned directly.

In addition, 36% of the HP network will likely be required to support the continuation of gas supply to those that need it during the transition from gas to hydrogen. This relatively high proportion stems from the configuration of the HP network in Somerset.

As a result of the above, the need for new hydrogen network represents more than 70% of the length of the existing HP network.

North Somerset

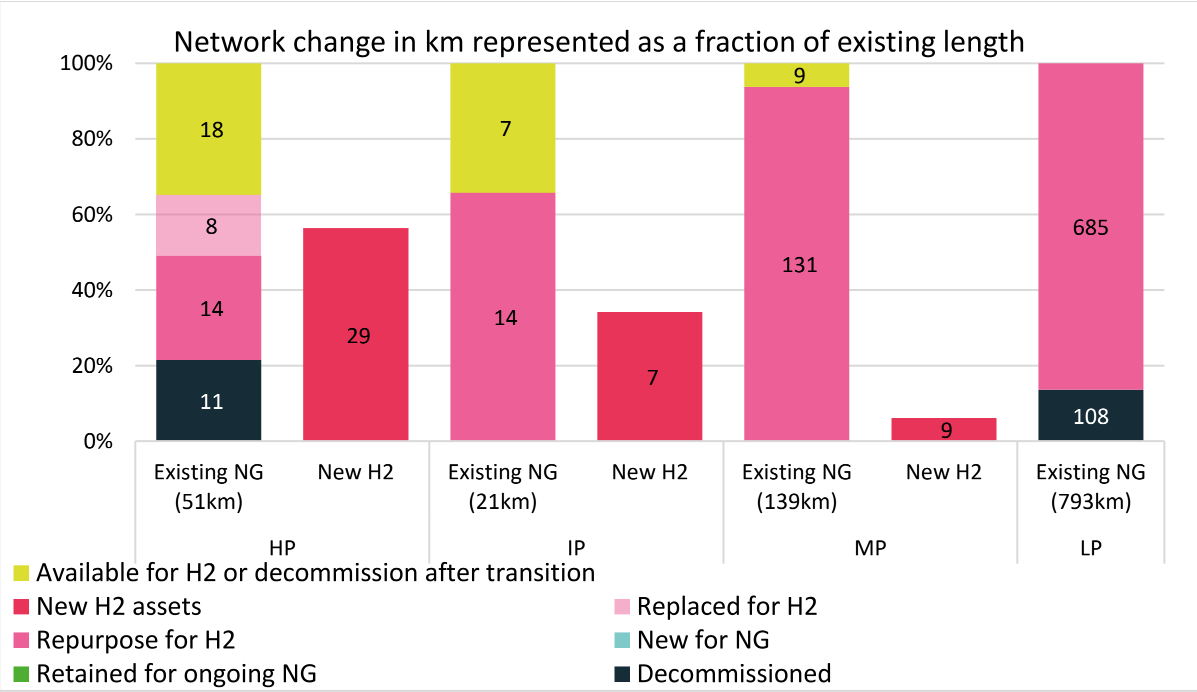


Figure 122: Network changes as a percentage of existing pressure tier length in North Somerset

The North Somerset sub-region does not include any remaining natural gas demand in 2050. As a result, its existing network is repurposed, decommissioned of maintained to provide storage to the gas network.

Medium Pressure

Most of the existing MP network (94%) could be repurposed to hydrogen by 2050. The remaining 6% is required to ensure continuation of gas supply to those that need it during the conversion to hydrogen networks. After transition is complete these can either be kept for reinforcement or decommissioned by 2050. New hydrogen pipe would have to be built along this same 6% pipes to allow for the transition.

Intermediate Pressure

The IP network in North Somerset is relatively short, and consists of individual sections across the sub-region, used to connect between MP and HP. As a result, around a third of the existing network would be needed to remain on natural gas for the duration of the transition, and an equivalent amount of new hydrogen IP would need to be built to supply hydrogen.

High Pressure

Around 38% of the HP network are 'vintage' pipelines and will therefore be decommissioned by 2050. More specifically around 16% would need to be replaced by hydrogen pipelines, while 22% should be decommissioned. Around 35% of the HP network corresponds to routes that are supplying areas above the connection's threshold. These assets would therefore have to be kept on natural gas during the time necessary to operate the transition to hydrogen, after which they could be made available for either reinforcement, storage or decommission (The actual outcome for each of these assets could be informed by more detailed studies such as flow analysis). As a result, the need for entirely new hydrogen pipes would correspond to around 56% of the length of the existing network.

WECA

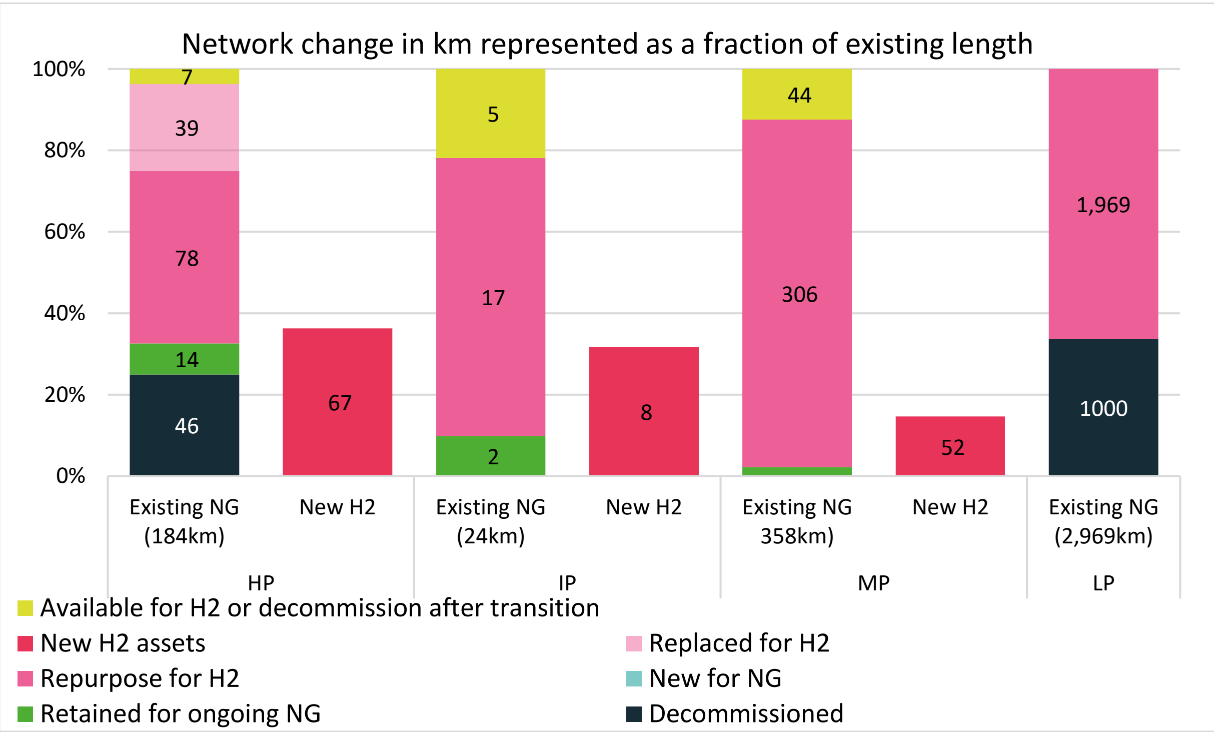


Figure 123: Network changes as a percentage of existing pressure tier length in WECA

A high proportion of the distribution network in WECA serves urban areas with a highly interconnected network.

Medium Pressure

The MP network located around the Bristol area is relatively dense and interconnected, meaning the level of redundancy is high and the quantity of pipes which are the unique supply to a high number of connections is low. Only 12% of the network would be required to remain on natural gas for the duration of the transition because of this constraint.

Less than 3% of the MP network would be required to sustain ongoing natural gas demand in 2050. This corresponds to the last few kilometers to reach the only remaining industrial demand site in the East of the WECA area.

As a result of expected low need for ongoing supply and transition, 85% of the existing MP could be repurposed to hydrogen service. The need for new hydrogen assets would therefore correspond to around 15% of the existing network length.

Intermediate Pressure

The IP network in WECA is short, relative to other pressure tiers and mostly consists of branches between MP and HP sections. Hence, the 10% that could be retained for ongoing natural gas demand only correspond to a stretch of a few kilometers, on the route that supplies the remaining industrial natural gas demand. Nearly a quarter (22%) would be required for the transition, corresponding to assets which are the unique route to supply a too high number of connections (as explained in section 7). These assets could either be decommissioned or used to reinforce the 2050 hydrogen network, after the transition is operated. The remaining 68% of the IP network could be repurposed for hydrogen supply. As a result, the new hydrogen assets needed in 2050 would represent more than 30% of the existing network.

High Pressure

The HP network in WECA has a relatively strongly interconnected structure, in comparison to other sub-regions studied. As a result, only 8% of its length would be needed for ongoing natural gas demand, and a further 4% for transition, due to constraints caused by high numbers of connections dependent on a single section of the network. A total of 46% of the pipelines could be decommissioned by 2050 because considered ‘vintage’. More specifically, 21% could be replaced for use in the hydrogen network, and 25% decommissioned without the need for replacement. This would leave around 42% of the existing network to be directly converted to hydrogen supply. As a result. The need for newly built hydrogen assets could amount to around 36% of the length of existing natural gas network.

23.5. CONCEPTUAL PLAN

The Conceptual Sub Regional Pull Outs are based on engineering analysis which considers the implications of the scenarios for natural gas and hydrogen infrastructure. This provides a basis to understand the decisions which are required around investment in network infrastructure to support decarbonisation and, provide an indicative illustration of the uptake of conversion of Domestic and Commercial meters to hydrogen between 2020 and 2050, across the three scenarios.

23.5.1. INSIGHTS SUMMARY – WECA, GLOUCESTER, WILTSHIRE AND SOMERSET

- Although a major hydrogen producing region the WECA, Gloucester, Wiltshire, And Somerset area is likely to still be a net importer of Hydrogen. Probably from the South Wales area. The network in this area is also likely to transport outward hydrogen to Devon and Cornwall.
- Potential to Repurpose: The majority of the LTS system in WECA, Gloucester, Wiltshire, And Somerset area (Figure 57) was constructed from pipe material strength grade of X52 and below. These pipe materials are suited to the transportation of hydrogen however, where pipelines have been constructed of higher strength grade then further work may be required to be undertaken prior to conversion to confirm their suitability. There are also a number of sections of the LTS network in this area which are over fifty years old and may potentially reach the end of the pipelines useable life shortly. Some of these older pipelines may also have been used for Towns Gas service, which can also suffer from further degradation due to the effect of hydrogen on the pipe wall. Where these pipelines are to be replaced then it is recommended that they are replaced with pipelines suitably sized and with a pipe material grade which suitable for hydrogen service.

Table 30. WECA, Gloucester, Wiltshire and Somerset Meters Converted per 5 Year Cycle

WECA, Glous, Wilts & Somerset	Number of Meters Converted per 5 Year Cycle						
	2020	2025	2030	2035	2040	2045	2050
High Electrification	0	0	0	1340	3134	0	0
Balanced	0	0	875	1831	1917	0	0
High Hydrogen	0	0	1153	1948	1522	0	0

- It can be seen from Table 30 that under the Balanced and High Hydrogen scenarios conversion starts circa 2030, while the High Electrification scenario starts approximately 5 years later. The workforce size requirements to undertake conversion will be similar for Balanced and High Hydrogen. However High Electrification has a peak conversion in 2040, where the conversion rate is slightly above the recommended number of 2500 per week.
- All three scenarios in South Wales will require similar levels of new pipeline infrastructure to enable conversion to hydrogen. In total approximately 535.6 km of new high pressure LTS hydrogen pipeline would be required in South Wales by 2045. Also, an additional 75 km of new natural gas pipeline would be required to either feed natural gas to hydrogen production facilities or provide cross connections within the existing network during conversion.

Table 31. WECA, Gloucester, Wiltshire and Somerset KM of New Hydrogen Pipeline per 5 Year Cycle

WECA, Glous, Wilts & Somerset	KM of New Hydrogen Pipeline per 5 Year Cycle						
	2020	2025	2030	2035	2040	2045	2050
High Electrification Scenario	0	0	0	78.1	457.5	0	0
Balanced & High Hydrogen Scenarios	0	0	66.8	255.6	213.2	66.1	0

Table 25 details an indicative level of the length of new hydrogen pipeline required in a particular 5 year cycle.

23.5.2. BALANCED (BAL)

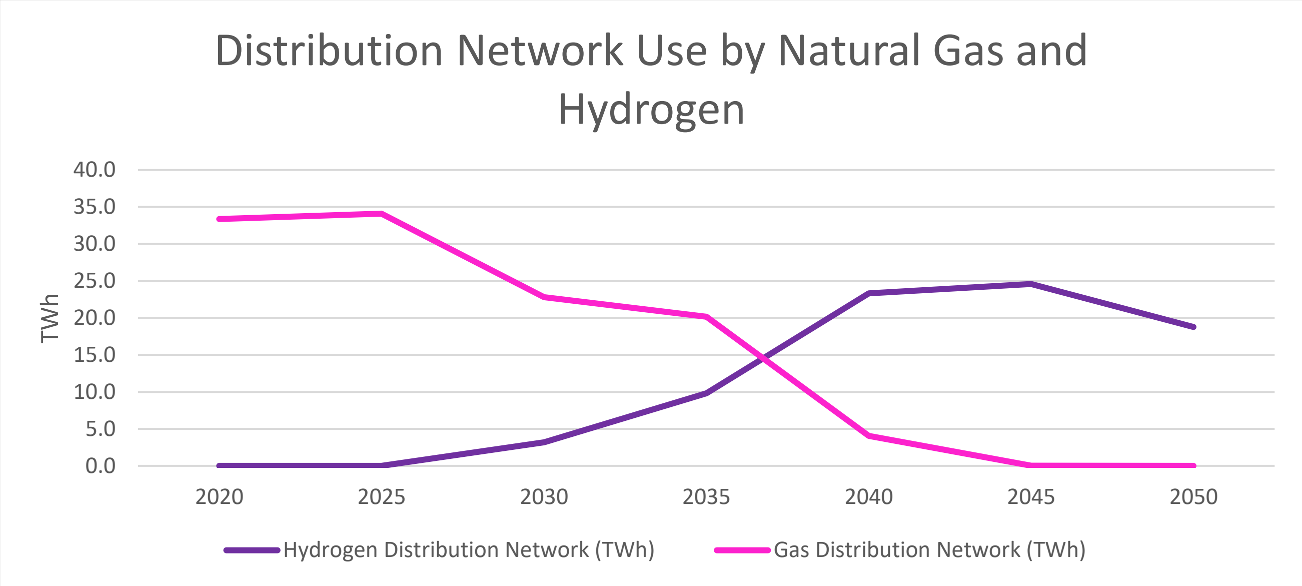
Table 18 shows the forecast hydrogen production and, distribution network consumption of natural gas and hydrogen for the Balanced (BAL) WWU scenario modelled in ESME in the South West. It can be seen that Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Initially hydrogen is supplied to industrial users and starts to be supplied to the distribution system before 2030 with the system supplying the maximum predicted hydrogen demand in 2045. Before consumption drops away towards 2050. Conversion of the Distribution Network is completed shortly after 2040.

Table 32. South West Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

South West	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.0	0.0	4.7	14.3	15.0	13.9	13.9
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	3.2	9.8	23.3	24.6	18.8
Natural Gas Consumption from Distribution Network (TWh)	33.4	34.1	22.8	20.1	4.0	0.0	0.0

Figure 124 South West Distribution Network Use by Natural Gas and Hydrogen – Balanced



As detailed in Section 10, a small number of larger emitters dominate present industrial emissions in the WECA, Gloucester, Wiltshire and Somerset area. There are a small concentration of these in the Bristol / Avonmouth area a number of single large emitters spread out along the River Severn and in the Trowbridge area. The decisions taken by the major emitters to decarbonise their emissions will have a significant impact on the energy transition solutions deployed in the region. Figure 125 shows the NAEI Sector and Emission Tonnage for the major emitters of carbon dioxide in WECA, Gloucester, Wiltshire and Somerset.

Figure 125 WECA, Gloucester, Wiltshire and Somerset – NAEI Large Emitters By Sector and Emissions Tonnage

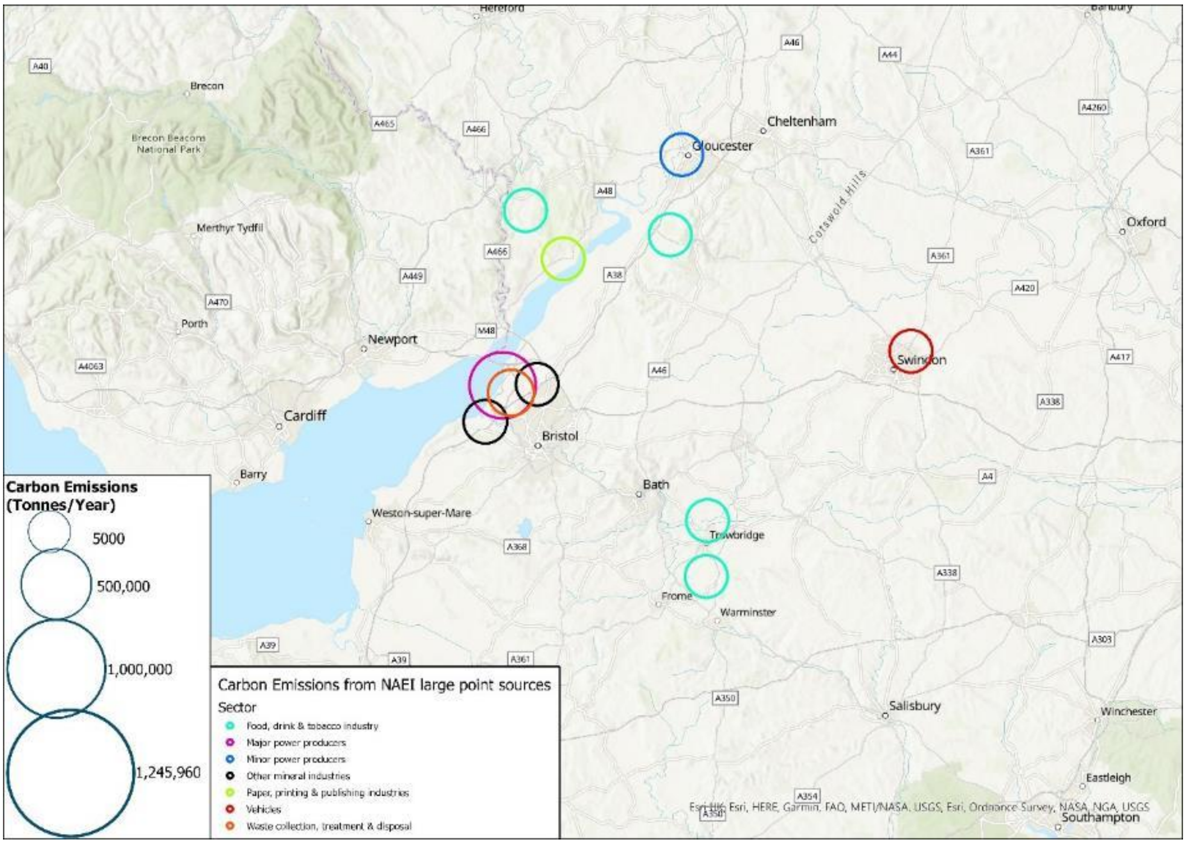


Table 33. WECA, Gloucester, Wiltshire and Somerset Meters Converted per 5 Year Cycle – Balanced

South West	Number of Meters Converted per 5 Year Cycle – Balanced						
	2020	2025	2030	2035	2040	2045	2050
Cirencester	0	0	0	43450	0	0	0
Easton Grey	0	0	0	90973	0	0	0
Evesham	0	0	0	0	39377	0	0
Fiddington	0	0	0	2251	144393	0	0
Ilchester	0	0	0	0	175158	0	0
Littleton Drew	0	0	0	6789	0	0	0
Seabank	0	0	175035	101958	0	0	0
Pucklechurch	0	0	0	120845	0	0	0
Ross	0	0	0	0	24441	0	0
Total	0	0	175035	366267	383367	0	0
Meters Converting per Week (40 Wks/Year)	0	0	875	1831	1917	0	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period i.e. over 40 weeks per year (March to November).

Figure 126 2030 Balanced – Domestic and Commercial Meters

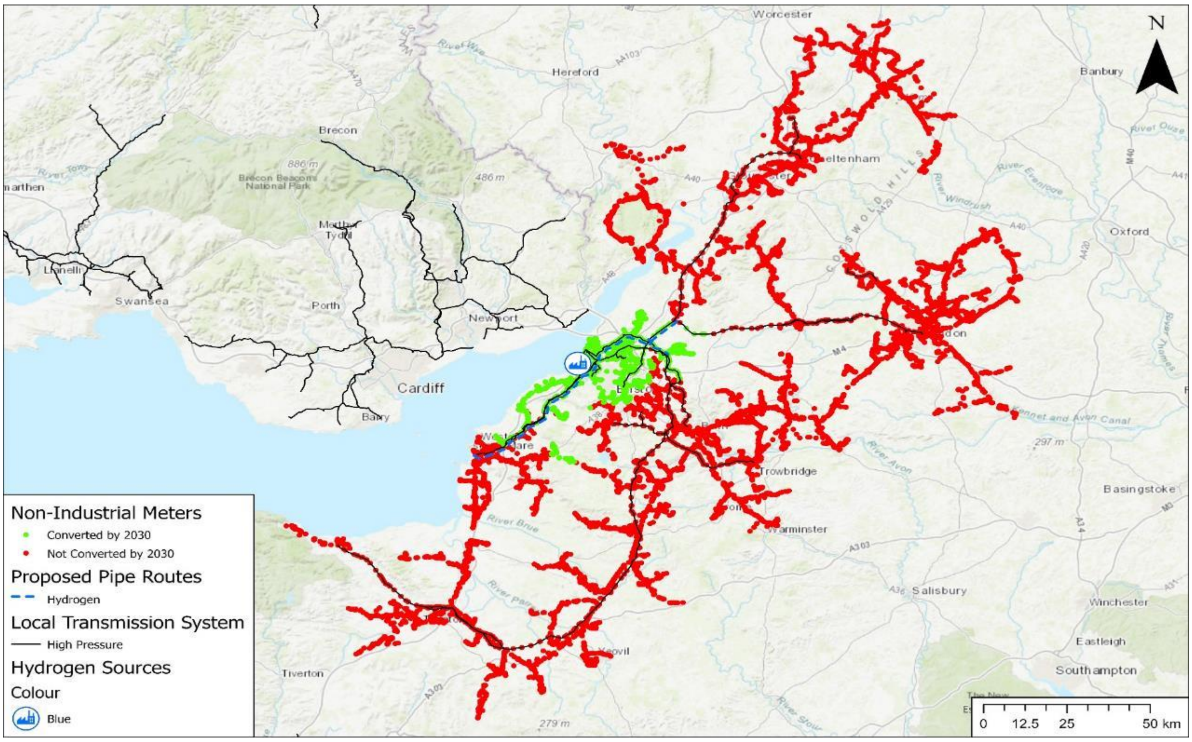


Figure 127 2035 Balanced – Domestic and Commercial Meters

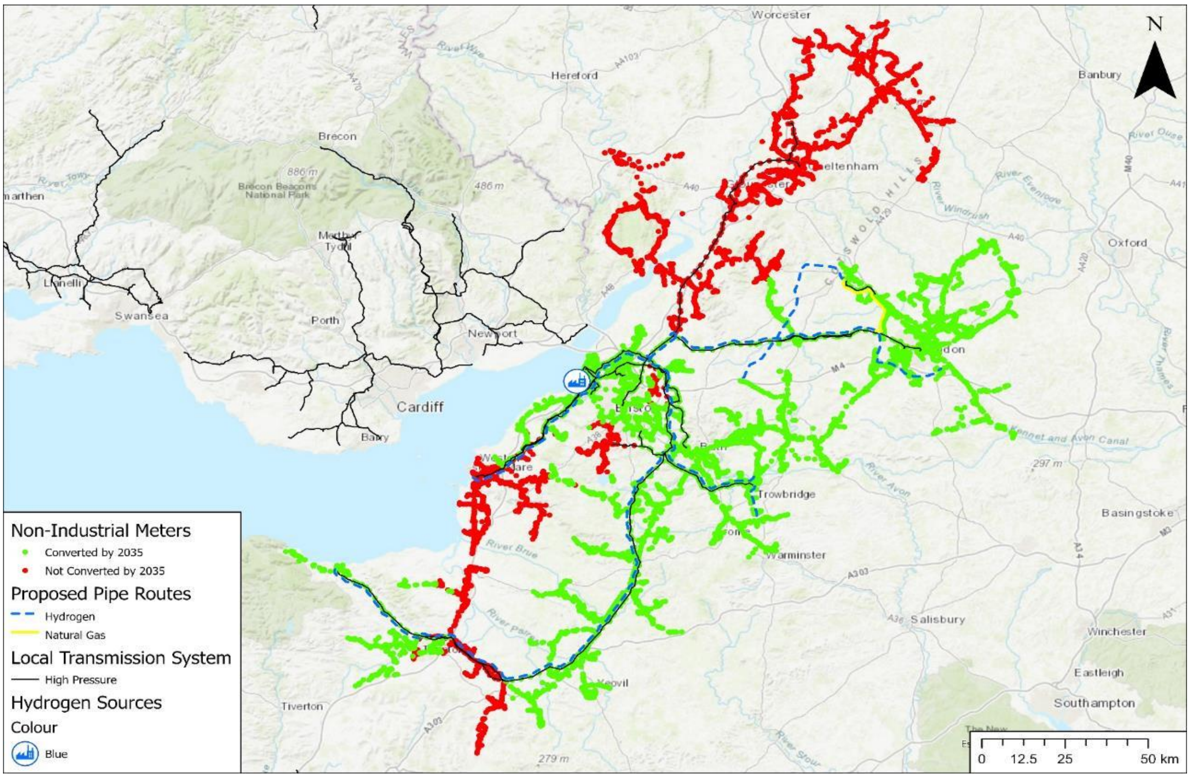


Figure 128 2040 – 2050 Balanced – Domestic and Commercial Meters

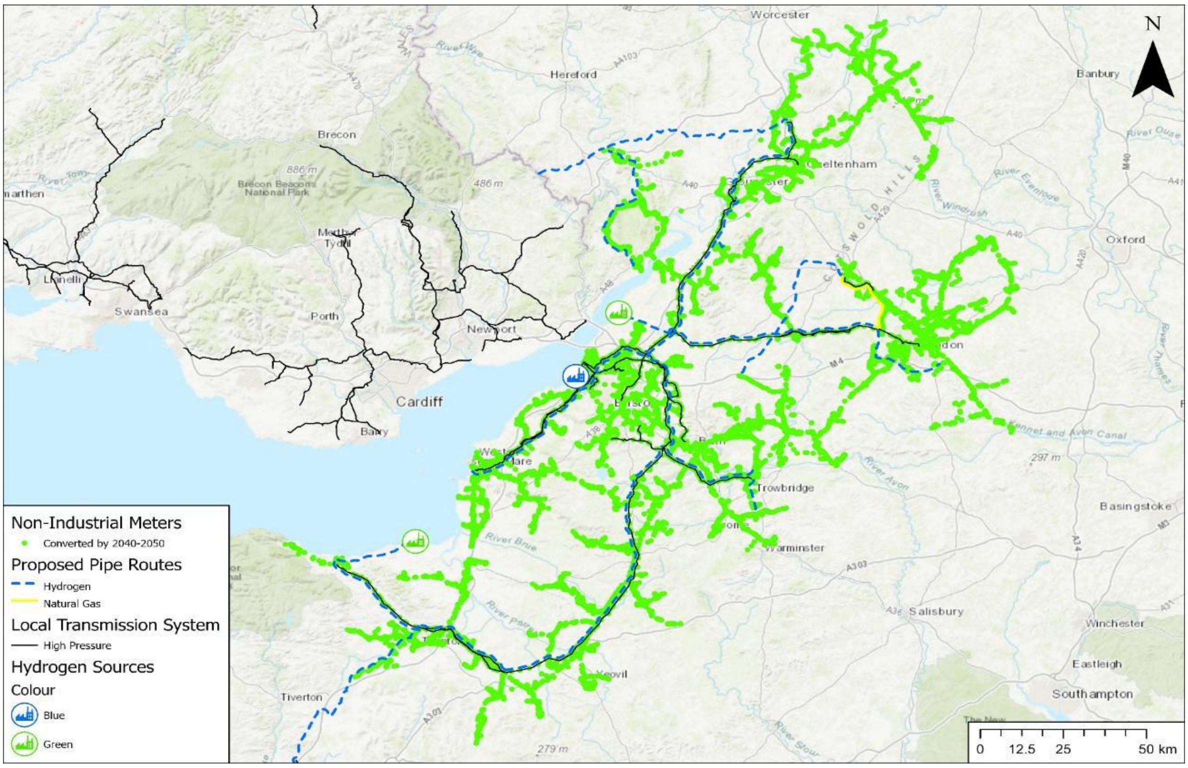
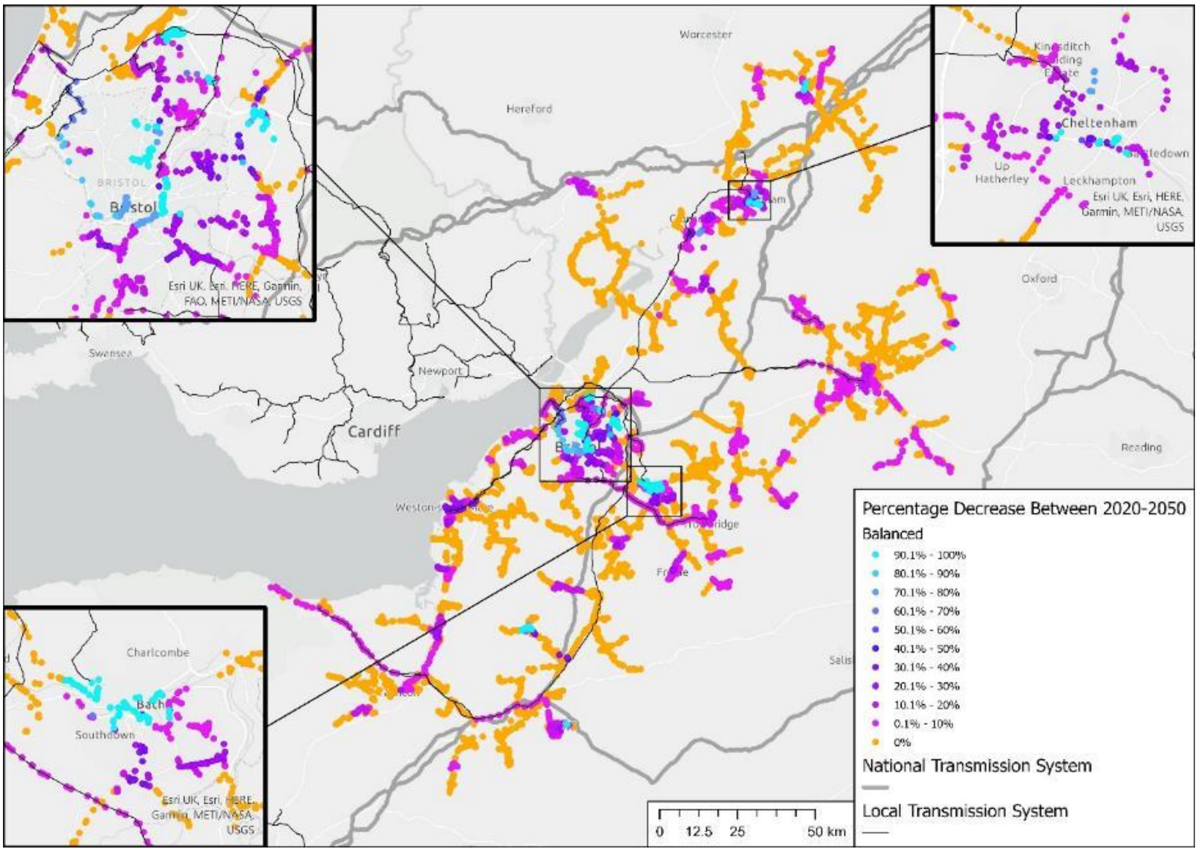


Figure 129 % Change in the Domestic and Commercial Meters – Balanced in 2050



Under the Balanced scenario there will be an approximate 35% reduction in the number of non dependent meters. Details the areas where there is predicted to be a fall in the number of customers on the gas system. A higher proportion of meters are lost in the centre of a number of the major conurbations, where district heating takes over as the source of domestic heat load.

23.5.3. COMPARISON OF THE THREE SCENARIOS

According to the ESME Whole System Overview (Section 6), for all three scenarios hydrogen production ramps up and peaks in similar timescales. Production of hydrogen and hydrogen consumption from the distribution network are broadly similar for High Hydrogen (101% of balanced). However, in the High electrification case, production of hydrogen and hydrogen consumption from the distribution network is lower than the Balanced scenario (73% of Balanced).

As can be seen from Figure 129, there are falls in the number of domestic meters in the major conurbations and this is broadly reflected across all three scenarios with a slightly greater reduction in the numbers of meters in the High Electrification scenario.

The quantity of new pipeline required will be similar across all three scenarios, due in part to the requirements for the system to be able to supply peak demand. However, for the High Electrification case, pipeline diameters may be slightly smaller than those required for the High Hydrogen and Balanced scenarios.

Details of the Conceptual Plan analysis of Electrification and High Hydrogen scenarios can be found in Section E.

SECTION D - SUB-REGIONAL ANALYSIS

DEVON PULL OUT*

* This sub-regional analysis should be read in conjunction with Parts A, B and C of the report

24. SUB-REGIONAL NETWORK – DEVON

This sub-section of the report provides further interpretation for the sub-region of Devon of the whole systems modelling undertaken by the Energy Systems Catapult (ESC's) in Sections 6 and 7 and the engineering analysis undertaken by Costain in Sections 10 to 16 of the main report.

The Devon analysis is structured in a similar way to the earlier sections of the report, with the implications of ESC's modelling set out in a Strategic Plan sub-section (see section 24.2) and the Costain engineering analysis set out in a Conceptual Plan section (see section 24.5). In advance of both these sub-sections, an overview of the key features of North Wales is provided (see Section 24.1).

24.1.OVERVIEW OF DEVON

The modelling used as the basis for this Devon sub-regional analysis is applied directly to the geographical area of the County of Devon which is inside WWU's South-West license area, and this includes almost the entire county.

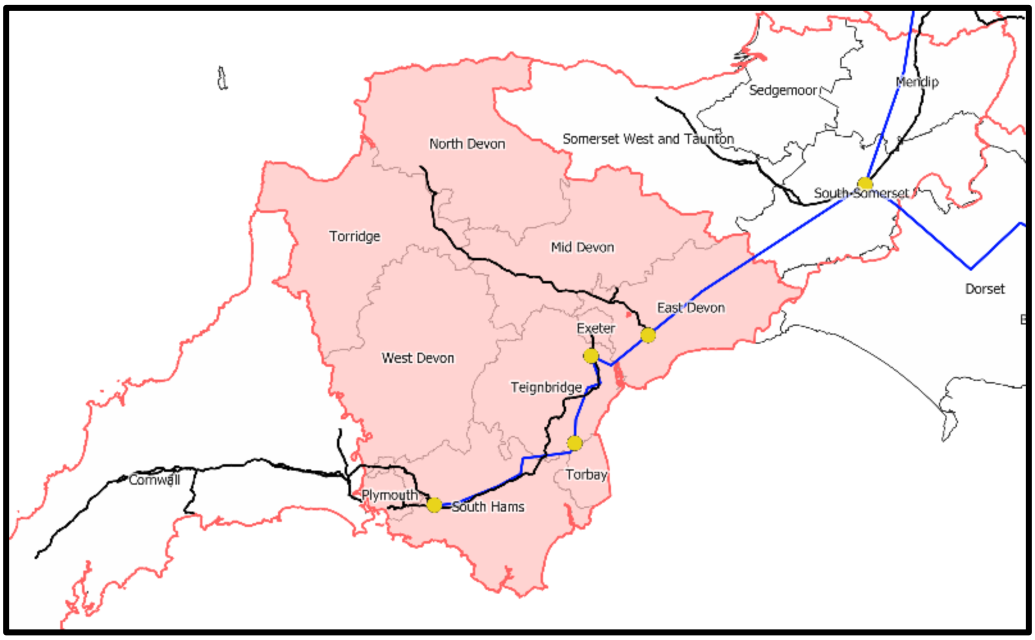


Figure 130: The Devon sub-region at present. The black lines show WWU's high-pressure (HP) network. The approximate route of the national transmission system (NTS) gas pipelines is shown in blue. Yellow circles represent 'offtakes' where gas flows from the NTS to the HP network.

Natural gas demand in Devon is supplied by a sole National Transmission System (NTS) pipeline from eastern part of the county to the offtake at Plymouth. Four LTS offtakes, close to the urban centres of the county supply the local distribution system owned and operated by WWU. The network in the south is focused on supply of urban centres with an interconnected network at the lower pressure tiers. In the northwest of the subregion the network is of linear nature supplying rural areas.

24.2. KEY INSIGHTS

Analysis undertaken in the Regional Decarbonisation Pathways project has developed a number of key insights for the development of a Net Zero energy system in Devon.

ESC's Strategic Plan (detailed in sections 24.3 to 24.4) found that:

- A high proportion of domestic and business gas network connections are required to be retained under all of the scenarios analysed, driven by the significant uptake of hybrid heating systems and standalone hydrogen boilers. The way the gas grid is used and the volume of hydrogen flowing through it is likely to be very different
- Disconnections from the mains gas for heating are driven by switching to district heating networks. District heat is deployed in the most densely built-up areas where it is most economical, and so disconnections from mains gas are concentrated in such areas, too.
- Across all three scenarios, the quantity of network infrastructure required to serve the retained natural gas and new hydrogen demands in North Wales are the same, though the volume they will supply varies. There is extensive opportunity to use existing infrastructure to serve these demands: both the low and medium pressure networks indicate a high proportion of repurposing.

Costain's Conceptual Plan (detailed in t section 24.5) found that:

- Devon is likely to be a net importer of hydrogen. Opportunities for 'blue' hydrogen production, exist near Plymouth on the basis of the availability of shipping infrastructure. There is also potential for hydrogen production via electrolysis.
- There are a small number of larger emitters. The decisions taken by the major emitters to decarbonise their emissions will have a significant impact on the energy transition solutions deployed in the region, and the timing of the infrastructure developments required.

24.3. STRATEGIC PLAN ANALYSIS (WHOLE SYSTEM MODELLING)

ESC's Strategic Plan analysis has been developed to provide insights into the possible future role of the gas network in Devon. It uses, as its basis, three whole system energy scenarios developed in collaboration with Wales and West Utilities and Costain, to explore different futures for hydrogen use in the South-West of England and Wales. These three UK-wide, whole energy system scenarios are described in Section 5.5 of the main report and are:

- Consistent with the UK's 2050 Net Zero and interim, statutory carbon targets.
- Identify three levels of hydrogen use for the South-West of England as part of the wider UK energy system.

This section should be read in conjunction with earlier parts of this document, to gain a full understanding for the context for the scenarios and the pathway for the broader whole energy system in the South-West of England, and the rest-of the UK. These three scenarios provide the basis for a strong role for hydrogen. Other scenarios will see less use and some more.

This is the first-time whole system energy modelling has been linked to sub-regional strategic network modelling analysis, to start to understand the potential shape and nature of the Wales and West Utilities (WWU) gas grid in 2050. This is network analysis and insights, based upon whole system modelling and there will be practicalities and engineering constraints faced by hydrogen network conversion. These considerations are further assessed in the sub-regional Conceptual Plans produced by Costain in sections 24.5 below.

This analysis does not replace the need for detailed network modelling and engineering-based feasibility and design but are intended as the basis for analysis and discussion.

24.4. STRATEGIC PLAN INSIGHTS

The key insights for gas and hydrogen networks in Devon, identified through this Strategic Plan analysis are:

- A high proportion of domestic and business gas network connections are retained in all three scenarios, driven by the significant uptake of hybrid heating systems (i.e., heat pumps providing baseload heat and hydrogen boilers providing peaking) and standalone hydrogen boilers. Despite this similarity, the proportion of these systems which are hybrid rather than standalone boilers, is significantly higher in the ELE scenario than in BAL and HYD, and the annual hydrogen consumption is correspondingly lower, as a greater proportion of baseline heat demand is met by electricity.
  District heat is deployed in the most densely built-up areas where it is most economical, and so disconnections from mains gas are concentrated in such areas, too.. In BAL, the conurbations around Plymouth, Exeter, and Torquay account for just over 85% of district heat networks by 2050.
- The similarity in the number of retained non-industrial connections and industrial fuel switching patterns translates to almost identical requirements for changes to the network infrastructure by 2050 (lengths of new/repurposed pipe etc.) in all three scenarios despite the substantial variation in the amount of hydrogen consumed for heat. While uncertainty around the optimality the level of hybrid heating systems deployment in our modelling means that these interventions cannot be interpreted as a 'low-regret' option, it does illustrate how systems with quite different amounts of hydrogen consumption could require similar levels of investment to support the transition from natural gas.

We have allocated all hydrogen production by BECCS in the South West region, and a portion of the 'blue' hydrogen production, to an indicative site near Plymouth on the basis of the availability of shipping infrastructure for captured carbon and, in the case of 'blue' production, natural gas supply. Production by electrolysis in the South West region is concentrated at this site, but this technology only features in the BAL and HYD scenarios.

- Each scenario explored the quantity of network infrastructure required to serve the retained natural gas and new hydrogen demands. The changes needed for Devon are the same for all three scenarios. A potential opportunity to re-purpose existing natural pipe assets for service in a hydrogen network has been identified. Both the low and medium pressure networks indicate a high proportion of repurposing at 84% (3,855km) and 84% (627km) respectively of existing pipes.
  In the intermediate and high pressure tiers the opportunity is 49% (75km) and 4% (7km) of existing pipelines respectively. This insight is indicative and should be considered in the context of this modelling. A complete view of the feasibility of repurposing these assets will become available once industry technical, safety and network transition studies are completed.

24.4.1. SCENARIO ANALYSIS

The three whole system scenarios used as the basis of the modelling are the High Electrification (ELE), Balanced (BAL) and High Hydrogen (HYD) which are distinguished by several different assumptions summarised in section 6.1.2. The major distinguishing features of the scenarios (i.e., the results of the modelling) are their relative use of the type of heating system present in 2050:

- The ELE scenario sees a prevalence of electrical systems (heat pumps, electric resistive heaters) to provide heat in residential and non-domestic buildings, and hydrogen can operate in peak demand periods but with a limited load factor. This scenario favours hybrid electric-hydrogen[25] systems as a result.
- The BAL scenario, the amount of heat supplied by heat pumps is restricted and hydrogen and electrical systems are set to be equal, reflecting a world where no strong policy is supporting the deployment of heat pumps.
- The HYD scenario assumes that most heat is supplied by hydrogen-based heating systems (hybrid electric-hydrogen systems, hydrogen boilers) and policy supports deployment of hydrogen technology.

Further detail is provided in section 5.5 of the main report.

24.4.1.1. 2050 GASEOUS FUEL SUPPLY, PRODUCTION AND TRANSMISSION

Across the three scenarios explored in this project, both hydrogen and gas have a role within a Net Zero energy system in Devon in 2050. Natural gas is utilised in industry and for hydrogen production, but a further explanation of its continued use in 2050 is provided in section 6.2.6.

Given that all three scenarios have retained natural gas demand in 2050, an NTS is assumed to be available. Specific changes to national transmission assets have not been assessed as part of this analysis, however retained distribution networks indicate that two (Aylesbeare and Choakford) of the four existing NTS offtakes in Devon are required to supply natural gas in 2050 under each scenario. This results from remaining natural gas demand in 2050 in Cullompton, Bradninch and

[25] Hybrid systems use heat pumps to provide baseload heating and hydrogen boilers to provide peaking.

South Molton. A third offtake (Kenn) is required to supply natural gas during the transition but may not be needed by 2050.

Plymouth's proximity to port facilities and existing energy infrastructure makes it well placed to be a hub for hydrogen production. All hydrogen production is therefore proposed to be located in the vicinity of Plymouth for this investigation, including biomass with CCS, Blue hydrogen and electrolysis. All three technologies provide a supply of hydrogen in the BAL and HYD scenarios, however electrolysis is not present in the ELE scenario. This is likely due to the reduced demand for hydrogen in this scenario.

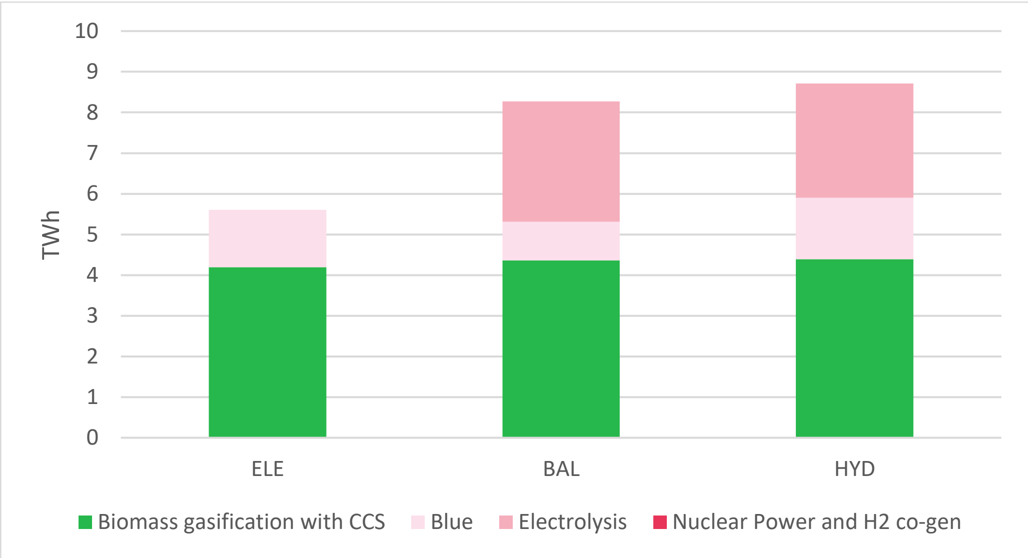


Figure 131: Annual hydrogen production in Devon in 2050 by scenario (TWh)

While some natural gas continues to be used by industry in 2050 across all three scenarios, most natural gas consumed in Devon is used as a feedstock for 'blue' hydrogen production[26]. This is one of the main drivers for retained natural gas networks in Devon in the scenarios explored, meaning that if the case for blue hydrogen were change through influencing factors such as cost of natural gas, a different network requirement is likely to emerge. This could subsequently have an impact on the economics of hydrogen networks and development through the transition.

[26] 'Blue' meaning that the production process yields carbon dioxide which is captured and stored.

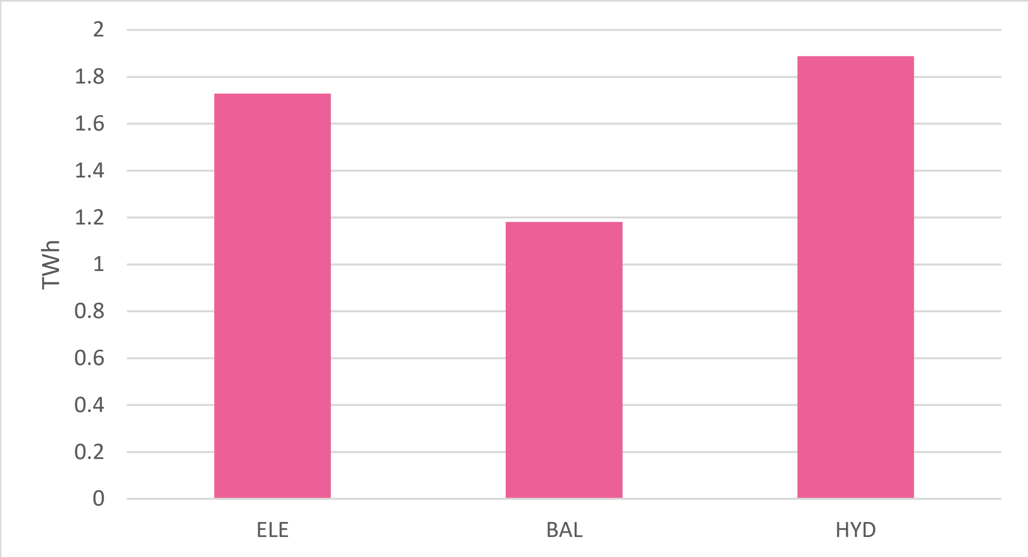


Figure 132: Natural gas consumption from blue hydrogen production in 2050 by scenario (TWh)

In 2050, a hydrogen NTS is also required to supply hydrogen distribution networks. Whilst specific network routing is not in scope for this project, we assume offtake points are available in locations similar to those that already exist for gas. Given the centralised nature of hydrogen production across the scenarios (i.e., predominantly blue hydrogen production), offtakes from the hydrogen NTS represents the primary source of hydrogen for the distribution networks in Devon.

24.4.1.2. GASEOUS FUEL CONSUMPTION

Industrial

Across all three scenarios, industrial natural gas demand in Devon in 2050 is from three large industrial sites, all of which are paper mills. These demands are assumed to all be retained out to 2050, however continued operation will ultimately be subject to a range of other economic factors, including the future of the energy system.

It is assumed that all sites in other industrial sectors can switch to hydrogen by 2050, supporting wider network transition. Practically, the switchover of industrial demands during network transition is likely to be complex, requiring consideration of both local network and stakeholder factors. Additional commercial and engineering analysis is required to identify interdependencies and understand how these can be managed to optimise network transition. Further details of how industrial demand has been modelled is provided in section 7.

Non-industrial

For the scenarios explored, domestic and commercial gas demand for space heating and hot water is replaced by a combination of hydrogen, electricity, and heat network-based heating solutions. Gas boilers are displaced by hydrogen boilers, hybrid hydrogen heat pumps, heat interface units for heat networks and electric resistive heating. The combination of these is an output of the regional strategic modelling (see section 6.2.12) and depends somewhat on the underlying assumptions informing each scenario.

Typically, in the ELE scenario, the bulk of the heat is supplied by electric heating systems, and hydrogen boilers are limited to backup operation at peak times. the presence of district heating is conditioned by the density type of buildings, making it more economical in denser areas where the transportation losses are reduced. The adoption of heat network is the main driver to disconnection from the gas network in 2050.

From a whole system perspective, hybrid boilers are valuable, reducing the capacity and associated cost of heat pumps whilst mitigating the expense of meeting high electricity peak demands and utilising existing infrastructure assets and low-cost storage. However, further work is required to understand the impact of network maintenance costs and the transitional capital costs to realise least cost system designs.

Notable differences identified between the scenarios include a much higher proportion of total heat production throughout the year due to Hydrogen boilers in HYD than in BAL, and in BAL than in ELE. Based on this analysis, switching from mains gas to district heating is the only driver of disconnection of non-industrial meters considered across all three scenarios.

24.4.1.3. CHANGES TO THE GASEOUS DISTRIBUTION NETWORKS

Non-industrial connections and low-pressure networks

Within Devon, all three scenarios tested suggest that 13-18% of domestic and commercial connections are removed and the remaining number switch from natural gas to hydrogen. 10-15% of the Low Pressure (LP) gas network is decommissioned, with most in the ELE scenario. Where connections switch away from a hydrogen supply, approximately 10-15% of homes across all three scenarios, have their heating provided through district heating in 2050 – see section 7 for more detail on the method. These heat networks

These modelling outputs suggests that large volumes of connections and LP network are retained across the scenarios, care is advised when interpreting this insight. The modelling method used is based on a breakdown of a least cost whole energy system for the UK to a regional level such as Devon. Resulting in retention of parts of the gaseous network which may be uneconomical in some scenarios. Further technical and economic analysis is required to obtain additional understanding of the interaction between local, regional, and national networks to enable cost optimal system design at each level. The scenarios here have indicated that where volumes of hydrogen reach low levels there could be a requirement to consider economic optimisation by assessment of further options between different levels of geographic granularity.

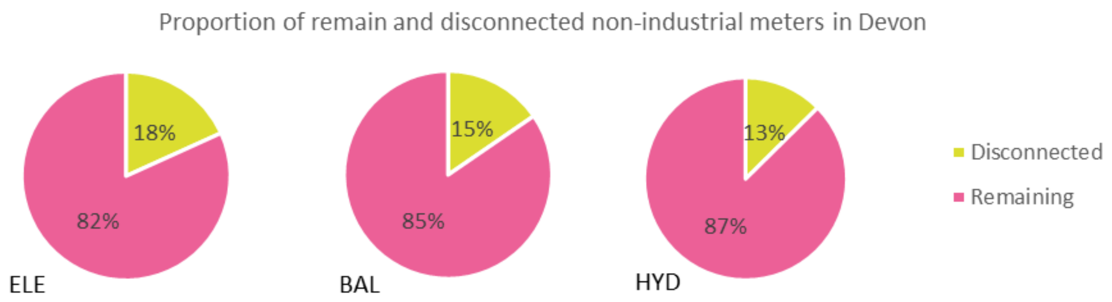


Figure 133 - Non-industrial disconnected and remaining meters in Devon (total number: 402,607)

Service pipes link the LP network to individual properties. An H21 project report[27] suggested a proportion of these could require replacement due to the higher volumetric flows of hydrogen required to supply a given amount of energy. There is significant uncertainty around this issue, and

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[27] NIA 275 H21 – Hydrogen Ready Services (https://h21.green/app/uploads/2021/02/NIA-275-H21-Hydrogen-Ready-Services-Final-Version.pdf) [Accessed 24/03/2022)

it has been suggested that many of these works could be avoided by various network level solutions, however this could have significant implications for customers. An estimated range of service pipe replacements for Devon is 329,000 to 352,000 across all three scenarios.

Medium, intermediate and high-pressure networks

Each scenario explored has an associated 'Bill of Quantities', indicating the quantity of infrastructure needed, summarised in Figure 134. This is the same for all three scenarios in Devon, discussed in section 7. Values are given as a percentage of the length of currently existing network for each respective pressure tiers – these are of 882km for the HP network, 379km for the IP network, and 937km of MP network.

In modelling the transition of networks from the network as it is today to one indicative of that required to serve the 2050 scenarios, the method re-purposes as much of the existing natural gas network for hydrogen service as possible. This was done whilst considering the need to maintain a natural gas supply through the transition and practical switching constraints of connections dependent on a natural gas supply to one receiving hydrogen. The result is an increased quantity of repurposing that is considered generous and reduced amount of new hydrogen. Transition of gas networks is recognised as a highly complex process and further analysis is required to fully understand the influencing factors to inform decisions. The detail of the modelling logic is provided in section 7.

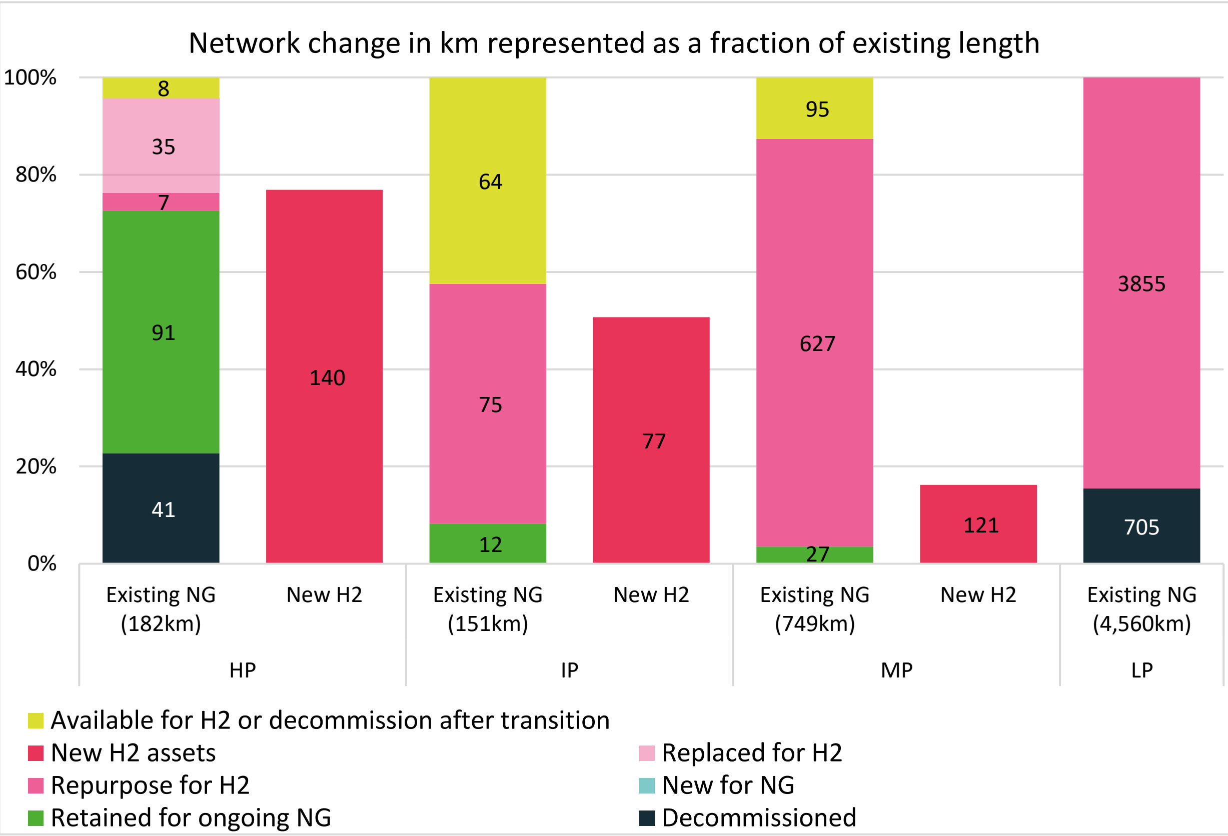


Figure 134: Network changes as a percentage of pressure tier existing length

Medium Pressure

The length of MP network still serving natural gas in 2050 could represent around 4% the length of the current network. The assets used for this purpose are the last few hundreds of meters between higher pressure tier pipelines, and industrial demand sites in South Molton, Bradninch and Cullompton. An additional 13% would be required to remain on natural gas supply for some time to allow for the transition to hydrogen, because they are currently the only route to a high number of connections. These assets would be made available to reinforce the hydrogen network or for decommission by 2050, subject to further studies such as flow analysis.

The rest of the MP network (84%) could be directly repurposed for hydrogen service, mostly due to the fact that they are free from the constraints of the above assets. This results in a potential requirement for entirely new hydrogen assets corresponding to around 16% of the existing MP network length.

Intermediate Pressure

A large section of the IP network in Devon corresponds to extensions of the HP network as linear stretches of pipes to reach MP networks. As a result, a high proportion of the existing IP network (42%) is constrained with high levels of dependencies (i.e., being the single route for a large number of connections) and would therefore be maintained for a certain time on natural gas. After the transition has been operated, such assets can be either converted to hydrogen service, or decommissioned, on the basis of further studies (which are out of the scope of the present project). Additionally, around 8% of the IP network could be retained on natural gas in order to supply ongoing demand out to 2050.

Where none of the above constraints apply, that is for about 49% of the existing network, the assets are repurposed to hydrogen service. As a result, the need for entirely new hydrogen pipes corresponds to about 45% of the existing network length.

High Pressure

Half of the existing HP network could be retained on natural gas demand in 2050, primarily driven by a long section of pipeline required to reach the South Molton demand site. Vintage pipes make up around 43% of the existing network, split between 20% which could be replaced for hydrogen and 23% which should not be required for either natural gas or hydrogen and would therefore be decommissioned by 2050.

Around 4% of the HP network is constrained with high dependencies and could be needed during the transition, after which they would be available for storage, reinforcement or decommissioning by 2050.

This results in around 4% of the network repurposed to hydrogen and the need for entirely new hydrogen pipes by 2050 representing around 77% of the length of the existing network.

24.5. CONCEPTUAL PLAN

The Conceptual Sub Regional Pull Outs are based on engineering analysis which considers the implications of the scenarios for natural gas and hydrogen infrastructure. This provides a basis to understand the decisions which are required around investment in network infrastructure to support decarbonisation and, provide an indicative illustration of the uptake of conversion of Domestic and Commercial meters to hydrogen between 2020 and 2050, across the three scenarios.

24.5.1. INSIGHTS SUMMARY – DEVON

- Hydrogen will potentially be produced to feed major emitters in the Plymouth area. However, Devon is still likely to be a net importer of Hydrogen, from the North. The network in this area is also likely to transport outward hydrogen to Cornwall.
- Potential to Repurpose: The majority of the LTS system in Devon (Figure 57) was constructed from pipe material strength grade of X52 and below. These pipe materials are suited to the transportation of hydrogen however, where pipelines have been constructed of higher strength grade then further work may be required to be undertaken prior to conversion to confirm their suitability. There are also a number of sections of the LTS network in this area which are over fifty years old and may potentially reach the end of the useable life shortly. Some of these older pipelines may also have been used for Towns Gas service, which can also suffer from further degradation due to the effect of hydrogen on the pipe wall. Where these pipelines are to be replaced then it is recommended that they are replaced with pipelines suitably sized and with a pipe material grade which suitable for hydrogen service.
- For all three scenarios in Devon approximately 85% (Section 9 ESC) of the Domestic and Commercial gas meters are estimated to be retained in 2050.

Table 34. Devon Meters Converted per 5 Year Cycle

Devon	Number of Meters Converted per 5 Year Cycle						
	2020	2025	2030	2035	2040	2045	2050
High Electrification	0	0	0	0	1002	1094	0
Balanced	0	0	0	0	1344	822	0
High Hydrogen	0	0	0	0	1308	858	0

It can be seen from Table 34 that under all three scenarios conversion starts circa 2040. The workforce size requirements are also similar for all three scenarios.

- All three scenarios in Devon will require similar levels of new pipeline infrastructure to enable conversion to hydrogen. In total approximately 129.5 km of new high pressure LTS hydrogen pipeline would be required in Devon by 2045.

Table 35. Devon KM of New Hydrogen Pipeline per 5 Year Cycle

Devon	KM of New Hydrogen Pipeline per 5 Year Cycle						
	2020	2025	2030	2035	2040	2045	2050
All Scenarios	0	0	0	0	129.5	0	0

Table 35 details an indicative level of the length of new hydrogen pipeline required in a particular 5 year cycle.

24.5.2. BALANCED (BAL)

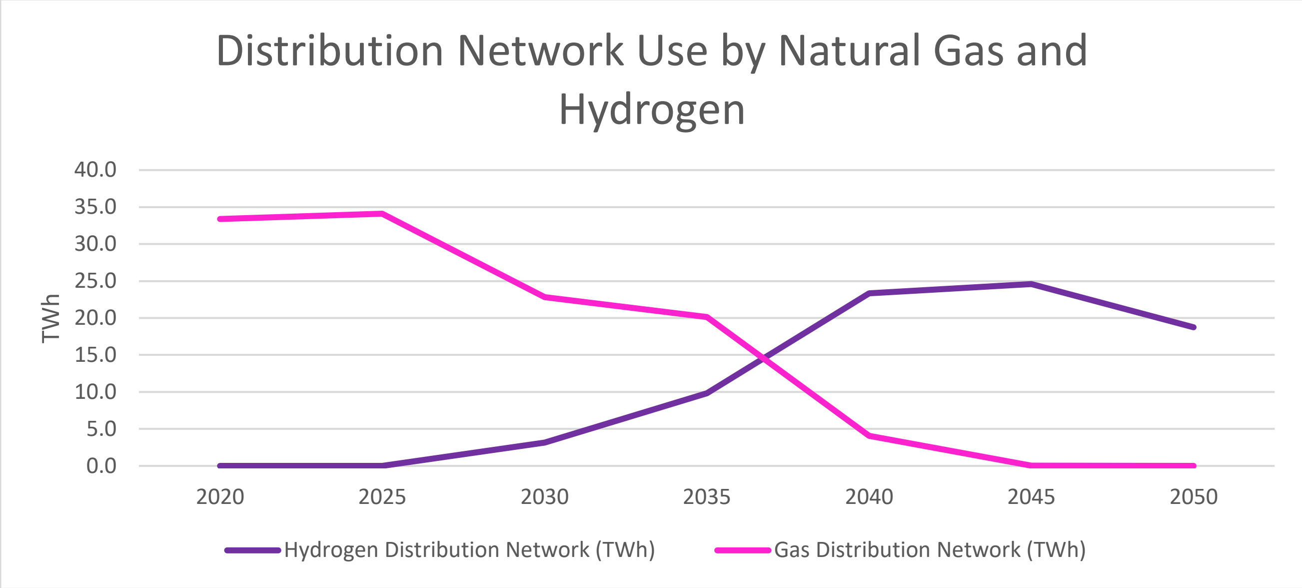
Table 18 shows the forecast hydrogen production and, distribution network consumption of natural gas and hydrogen for the Balanced (BAL) WWU scenario modelled in ESME in the South West. It can be seen that Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Initially hydrogen is supplied to industrial users and starts to be supplied to the distribution system before 2030 with the system supplying the maximum predicted hydrogen demand in 2045. Before consumption drops away towards 2050. Conversion of the Distribution Network is completed shortly after 2040.

Table 36. Devon Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

Devon	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.0	0.0	4.7	14.3	15.0	13.9	13.9
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	3.2	9.8	23.3	24.6	18.8
Natural Gas Consumption from Distribution Network (TWh)	33.4	34.1	22.8	20.1	4.0	0.0	0.0

Figure 135 South West Distribution Network Use by Natural Gas and Hydrogen – Balanced



As detailed in Section 10, there are only a few large emitters in the Devon area, concentrated along the south of the county, Figure 136 shows the NAEI Sector and Emission Tonnage for the major emitters of carbon dioxide in Devon.

Figure 136 Devon - NAEI Large Emitters By Sector and Emissions Tonnage

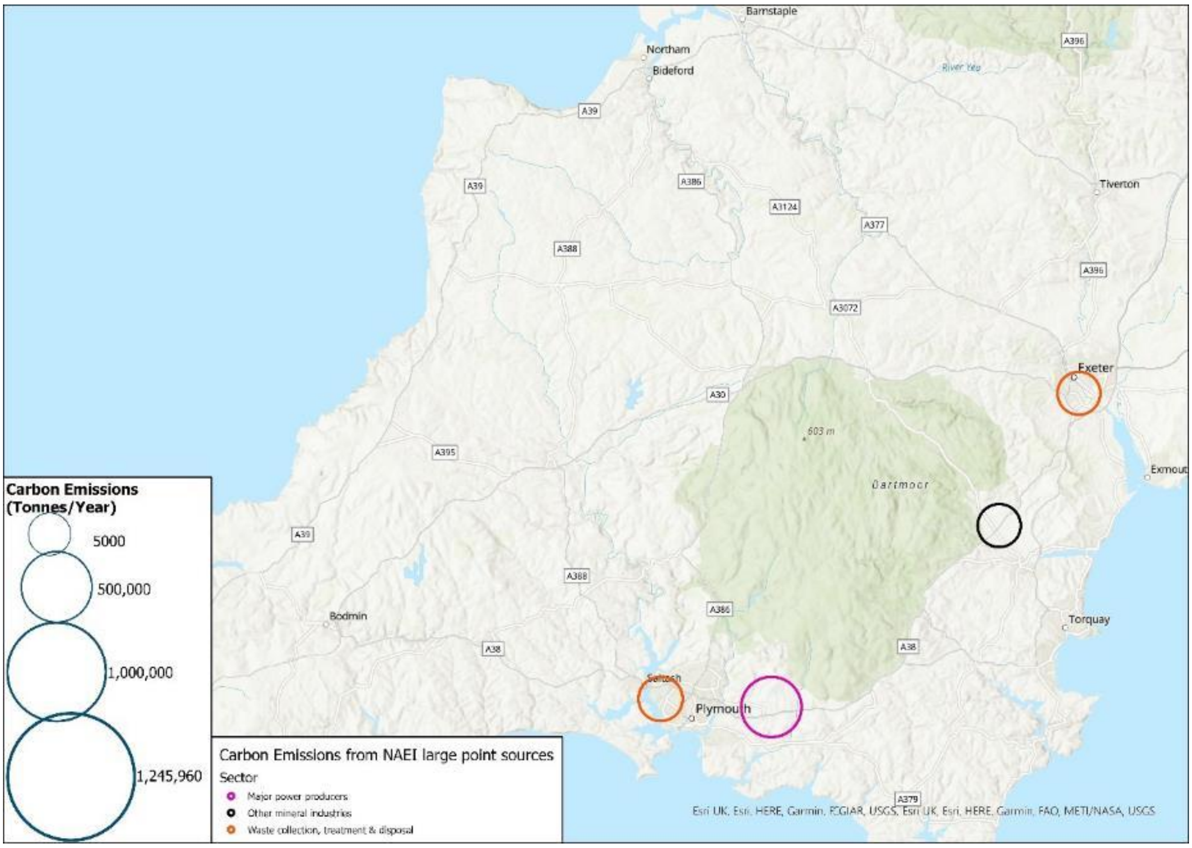


Table 37. Devon Meters Converted per 5 Year Cycle – Balanced

Devon	Number of Meters Converted per 5 Year Cycle – Balanced						
	2020	2025	2030	2035	2040	2045	2050
Aylesbeare	0	0	0	0	0	101836	0
Choakford	0	0	0	0	156148	0	0
Coffinswell	0	0	0	0	28514	0	0
Kenn	0	0	0	0	84120	62524	0
Meters Converting per Week (40 Wks/Year)	0	0	0	0	1344	822	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

Figure 137 2040 Balanced - Domestic and Commercial Meters

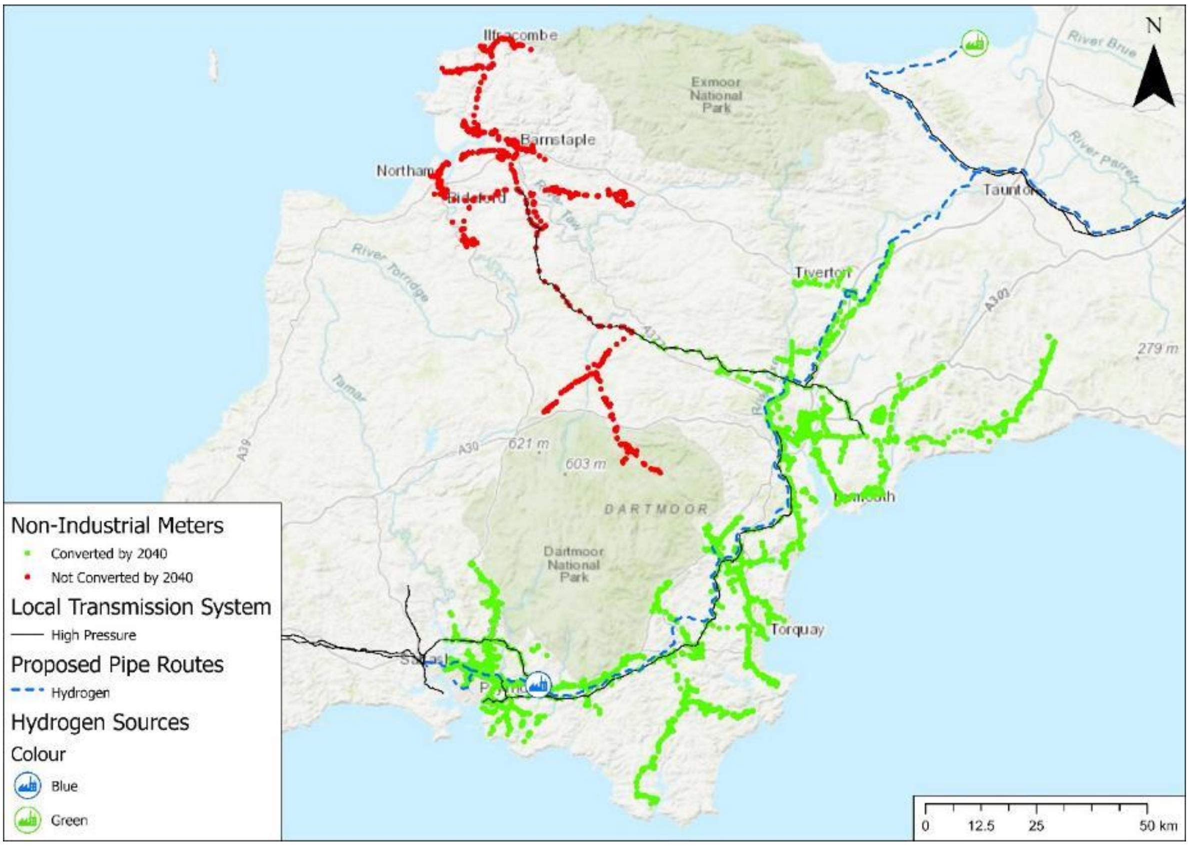


Figure 138 2045 - 2050 Balanced - Domestic and Commercial Meters

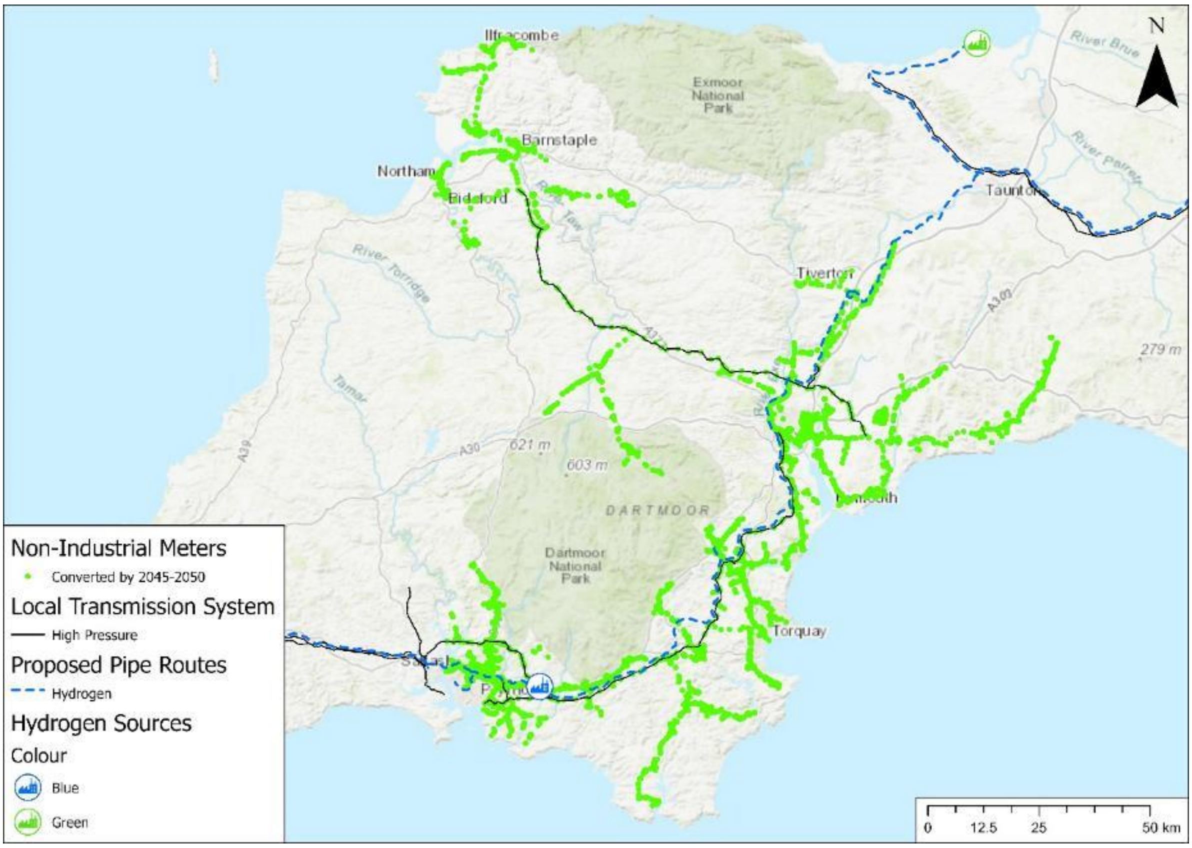
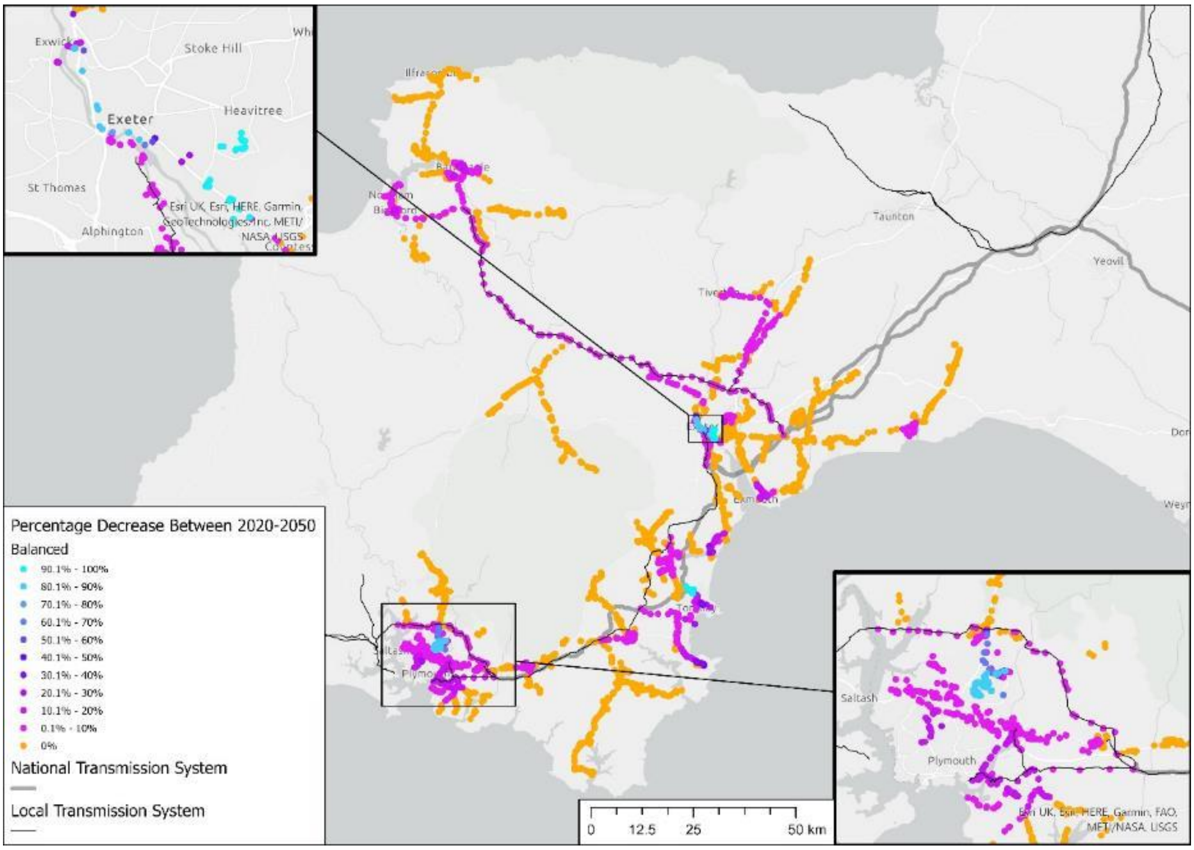


Figure 139 % Change in the Domestic and Commercial Meters – Balanced in 2050



Under the Balanced scenario there will be an approximate 16% reduction in the number of non dependent meters. Figure 139 details the areas where there is predicted to be a fall in the number of customers on the gas system. A higher proportion of meters are lost in the centre of the major conurbations, where district heating takes over as the source of domestic heat load.

24.5.3. COMPARISON OF THE THREE SCENARIOS

According to the ESME Whole System Overview (Section 6.2), for all three scenarios hydrogen production ramps up and peaks in similar timescales. Production of hydrogen and hydrogen consumption from the distribution network are broadly similar for High hydrogen (101% of Balanced). However, in the High electrification case, production of hydrogen and hydrogen consumption from the distribution network is lower than the Balanced scenario (73% of Balanced). As the number of domestic meters is broadly the same across all three scenarios, this would indicate that individual consumption is the primary variable rather than the number of supply points. As can be seen from Figure 14.48, there are falls in the number of domestic meters in the major conurbations and this is broadly reflected across all three scenarios with a slightly greater reduction in the numbers of meters in the High Electrification scenario.

The quantity of new pipeline required will be similar across all three scenarios, due in part to the requirements for the system to be able to supply peak demand. However, for the High Electrification case, pipeline diameters may be slightly smaller than those required for the High Hydrogen and Balanced scenarios.

Details of the Conceptual Plan analysis of Electrification and High Hydrogen scenarios can be found in Section E.

SECTION D -
SUB-REGIONAL ANALYSIS

CORNWALL PULL OUT*

* This sub-regional analysis should be read in conjunction with Parts A, B and C of the report

25. SUB-REGIONAL NETWORK ANALYSIS – CORNWALL

This sub-section of the report provides further interpretation for the sub-region of Cornwall of the whole systems modelling undertaken by the Energy Systems Catapult (ESC's) in Sections 6 and 7 and the engineering analysis undertaken by Costain in Sections 10 to 16 of the main report.

The Cornwall analysis is structured in a similar way to the earlier sections of the report, with the implications of ESC's modelling set out in a Strategic Plan sub-section (see section 25.2) and the Costain engineering analysis set out in a Conceptual Plan section (see section 25.5). In advance of both these sub-sections, an overview of the key features of North Wales is provided (see Section 25.1).

25.1. OVERVIEW OF CORNWALL

The modelling used as the basis for this Cornwall sub-regional analysis is applied directly to the geographical area of the Unitary Authority of Cornwall (see Figure 140). The analysis here focuses on the key features of the Cornwall gas distribution system and potential 2050 implications.

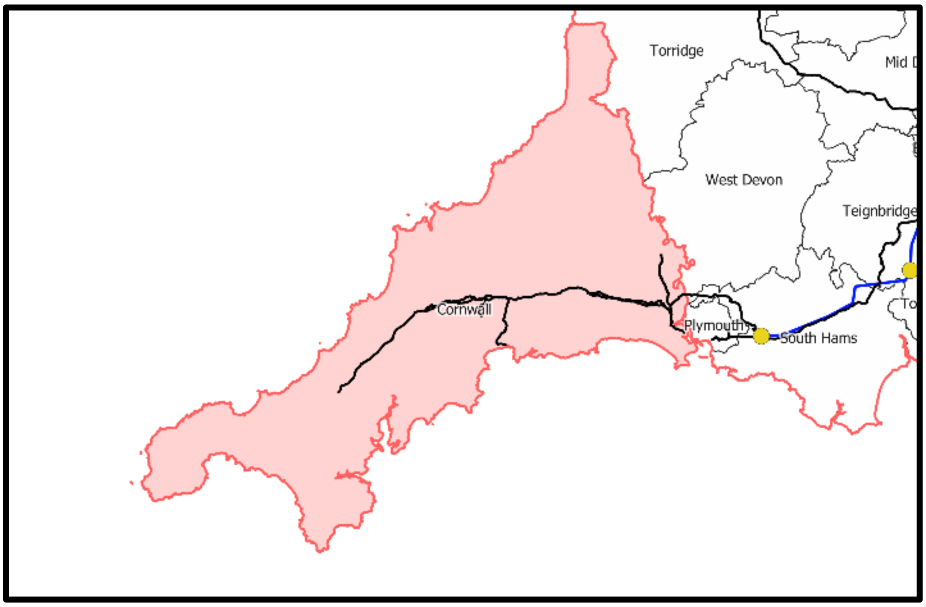


Figure 140: The Cornwall sub-region at present. The black lines show WWU's high-pressure (HP) network. The approximate route of the national transmission system (NTS) gas pipelines is shown in blue. Yellow circles represent 'offtakes' where gas flows from the NTS to the HP network.

The Cornish gas distribution system is supplied by a connection to the National Transmission System (NTS) outside the sub region, as such there is no NTS within Cornwall. The local gas distribution system serves connections in urban and rural areas from a linear network running from East to West. The high-pressure parts of the networks have linear characteristics throughout the region.

25.2. KEY INSIGHTS

Analysis undertaken in the Regional Decarbonisation Pathways project has developed a number of key insights for the development of a Net Zero energy system in Cornwall.

ESC's Strategic Plan (detailed in sections 25.3 to 25.4) found that:

- A high proportion of domestic and business gas network connections are required to be retained under all of the scenarios analysed, driven by the significant uptake of hybrid heating systems and standalone hydrogen boilers. The way the gas grid is used and the volume of hydrogen flowing through it is likely to be very different.
- Disconnections from the mains gas for heating are driven by switching to district heating networks. District heat is deployed in the most densely built-up areas where it is most economical, and so disconnections from mains gas are concentrated in such areas, too.
- Across all three scenarios, the quantity of network infrastructure required to serve the retained natural gas and new hydrogen demands in North Wales are the same, though the volume they will supply varies. There is extensive opportunity to use existing infrastructure to serve these demands: both the low and medium pressure networks indicate a high proportion of repurposing.

Costain's Conceptual Plan (detailed in section 25.5) found that:

- Cornwall will be a net importer of hydrogen.
- There are few larger emitters. The decisions taken by the major emitters to decarbonise their emissions will have a significant impact on the energy transition solutions deployed in the region, and the timing of the infrastructure developments required.

25.3. STRATEGIC PLAN ANALYSIS (WHOLE SYSTEM MODELLING)

ESC's Strategic Plan analysis has been developed to provide insights into the possible future role of the gas network in Cornwall. It uses, as its basis, three whole system energy scenarios developed in collaboration with Wales and West Utilities and Costain, to explore different futures for hydrogen use in the South-West of England and Wales. These three UK-wide, whole energy system scenarios are described in Section 5.5 of the main report and are:

- Consistent with the UK's 2050 Net Zero and interim, statutory carbon targets.
- Identify three levels of hydrogen use for the South-West of England as part of the wider UK energy system.

This section should be read in conjunction with earlier parts of this document, to gain a full understanding for the context for the scenarios and the pathway for the broader whole energy system in the South-West of England, within the wider context of the rest-of the UK energy transition. These three scenarios provide the basis for a strong role for hydrogen. Other scenarios will see less use and some more.

This is the first-time whole system energy modelling has been linked to sub-regional strategic network modelling analysis, to start to understand the potential shape and nature of the Wales and West Utilities (WWU) gas grid in 2050. This is network analysis and insights, based upon whole system modelling and there will be practicalities and engineering constraints faced by hydrogen network conversion. These considerations are further assessed in the sub-regional Conceptual Plans produced by Costain in sections 25.5, below.

This analysis does not replace the need for detailed network modelling and engineering-based feasibility and design but are intended as the basis for analysis and discussion.

25.4. STRATEGIC PLAN INSIGHTS

The key insights for gas and hydrogen networks in Cornwall, identified through this Strategic Plan analysis are:

- A high proportion of domestic and business gas network connections are retained in all three scenarios, driven by the significant uptake of hybrid heating systems (i.e., heat pumps providing baseload heat and hydrogen boilers providing peaking) and standalone hydrogen boilers. Despite this similarity, the proportion of these systems which are hybrid rather than standalone boilers, is significantly higher in the ELE scenario than in BAL and HYD, and the annual hydrogen consumption is correspondingly lower, as a greater proportion of baseline heat demand is met by electricity.

  District heat is deployed in the most densely built-up areas where it is most economical, and so disconnections from mains gas are concentrated in such areas, too. In BAL, the conurbations around Penzance, Falmouth, St Austell, Truro, and Saltash account for almost 80% of the dwellings on district heat networks by 2050.

- The similarity in the number of retained non-industrial connections and industrial fuel switching patterns translates to almost identical requirements for changes to the network infrastructure by 2050 (lengths of new/repurposed pipe etc.) in all three scenarios despite the substantial variation in the amount of hydrogen consumed for heat. While uncertainty around the optimality the level of hybrid heating systems deployment in our modelling means that these interventions cannot be interpreted as a 'low-regret' option, it does illustrate how systems with quite different amounts of hydrogen consumption could require similar levels of investment to support the transition from natural gas.

In all three scenarios, hydrogen production technologies other than electrolysis either require CCS or a site suitable for large scale nuclear plant, and the case for distributed electrolysis is weak due to the decrease in onshore solar and wind generation. Taking these factors into account, our allocation of hydrogen production places no capacity in Cornwall across the three scenarios – hydrogen consumed in Cornwall would be imported via the hydrogen NTS and LTS.

- Each scenario explored the quantity of network infrastructure required to serve the retained natural gas and new hydrogen demands. The changes needed for Cornwall are the same for all three scenarios. A potential opportunity to re-purpose existing natural pipe assets for service in a hydrogen network has been identified. Both the low and medium pressure networks indicate a high proportion of repurposing at 94% (1,392km) and 84% (357km) respectively of existing pipes.

  In the intermediate and high pressure tiers the opportunity is 36% (58km) and 33% (52km) of existing pipelines respectively. This insight is indicative and should be considered in the context of this modelling. A complete view of the feasibility of repurposing these assets will become available once industry technical, safety and network transition studies are completed.

25.4.1. SCENARIO ANALYSIS

The three whole system scenarios used as the basis of the modelling are the High Electrification (ELE), Balanced (BAL) and High Hydrogen (HYD) which are distinguished by several different assumptions summarised in section 6.1.2 of the accompanying report to this analysis. The major distinguishing features of the scenarios (i.e., the results of the modelling) are their relative use of the type of heating system present in 2050:

- The ELE scenario sees a prevalence of electrical systems (heat pumps, electric resistive heaters) to provide heat in residential and non-domestic buildings, and hydrogen can operate in peak demand periods but with a limited load factor. This scenario favours hybrid electric-hydrogen[28] systems as a result.
- The BAL scenario, the amount of heat supplied by heat pumps is restricted and hydrogen and electrical systems are set to be equal, reflecting a world where no strong policy is supporting the deployment of heat pumps.
- The HYD scenario assumes that most heat is supplied by hydrogen-based heating systems (hybrid electric-hydrogen systems, hydrogen boilers) and policy supports deployment of hydrogen technology.

Further detail is provided in section 5.5 of the main report.

25.4.1.1. 2050 GASEOUS FUEL SUPPLY, PRODUCTION AND TRANSMISSION

Across the three scenarios explored in this project, both hydrogen and gas have a role within a Net Zero energy system in Cornwall in 2050. The present natural gas NTS does not extend into

[28] Hybrid systems use heat pumps to provide baseload heating and hydrogen boilers to provide peaking.

Cornwall (Figure 140), supply from the existing NTS offtake in Devon is assumed to be available under all scenarios to the extent that it will meet retained regional natural gas demands in 2050.

Whilst there is hydrogen demand in Cornwall in 2050, the analysis has shown that there are locations within the WWU region which are more suitable for hydrogen production, resulting in no production within the county. Details of this method are discussed in section 7 of the accompanying report. A 2050 supply of hydrogen to Cornwall is assumed to be sourced from a hydrogen transmission system offtake in the vicinity of the existing natural gas offtake in Devon. All hydrogen consumed in Cornwall would be delivered by the distribution network from this supply point.

25.4.1.2. GASEOUS FUEL CONSUMPTION

In all scenarios, Cornwall contains a single large industrial site considered to have ongoing natural gas demand in 2050. This site is assumed to be retained out to 2050, however continued operation will ultimately be subject to a range of other economic factors, including the future of the energy system. It is assumed that all other industrial sites in Cornwall can, and have, made the switch to hydrogen by 2050, supporting wider network transition. Practically the switchover of industrial demands during network transition is likely to be complex, requiring consideration of both local network and stakeholder factors. Additional commercial and engineering analysis is required to identify interdependencies and understand how these can be managed to optimise network transition. Further details of how industrial demand has been modelled is provided in section 4.

For the scenarios explored, domestic and commercial gas demand for space heating and hot water is replaced by a combination of hydrogen, electricity, and heat network-based heating solutions. Gas boilers are displaced by hydrogen boilers, hybrid hydrogen heat pumps, heat interface units for heat networks and electric resistive heating. The combination of these is an output of the regional strategic modelling (see section 6.2.12) and depends somewhat on the underlying assumptions informing each scenario.

Typically, in the ELE scenario, the bulk of the heat is supplied by electric heating systems, and hydrogen boilers are limited to backup operation at peak times. the presence of district heating is conditioned by the density of buildings, making it more economical in denser areas where the transportation losses are reduced. The adoption of heat network is the main driver to disconnection from the gas network in 2050.

From a whole system perspective, hybrid boilers are valuable, reducing the capacity and associated cost of heat pumps whilst mitigating the expense of meeting high electricity peak demands and utilising existing infrastructure assets and low-cost storage. However, further work is required to understand the impact of network maintenance costs and the transitional capital costs to realise least cost system designs.

Notable differences identified between the scenarios include a much higher proportion of total heat production throughout the year due to Hydrogen boilers in HYD than in BAL, and in BAL than in ELE. Based on this analysis, switching from mains gas to district heating is the only driver of disconnection of non-industrial meters considered across all three scenarios.

25.4.1.3. CHANGES TO THE GASEOUS DISTRIBUTION NETWORKS

Non-industrial connections and low-pressure networks

Within Cornwall, all three scenarios tested suggest that 3-8% of domestic and commercial connections are removed and the remaining number switch from natural gas to hydrogen. Between 2% and 6% of the Low Pressure (LP) gas network is decommissioned, with most in the ELE scenario. Where connections switch away from a hydrogen supply, approximately 4% of homes across all three scenarios, they have their heating provided through district heating in 2050 – see section 4 for more detail on the method.

These modelling outputs suggests that large volumes of connections and LP network are retained across the scenarios, care is advised when interpreting this insight. The modelling method used is based on a breakdown of a least cost whole energy system for the UK to a regional level such as Cornwall. Resulting in retention of parts of the gaseous network which may be uneconomical in some scenarios. Further technical and economic analysis is required to obtain additional understanding of the interaction between local, regional, and national networks to enable cost optimal system design at each level. The scenarios here have indicated that where volumes of hydrogen reach low levels there could be a requirement to consider economic optimisation by assessment of further options between different levels of geographic granularity.

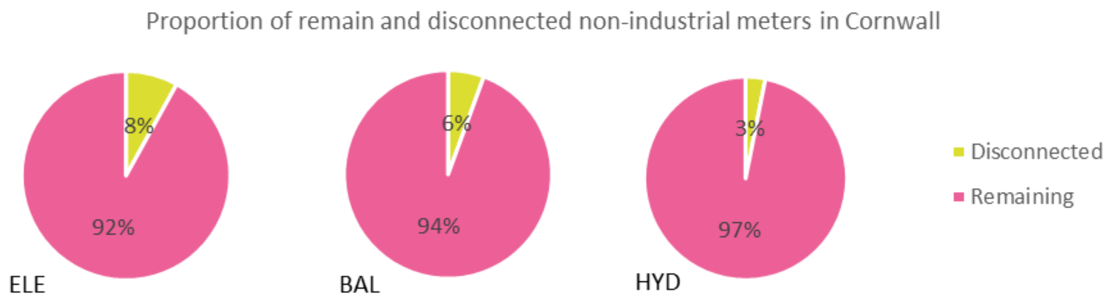


Figure 141: Non-industrial disconnected and remaining meters in Devon (total number: 137,675)

Service pipes link the LP network to individual properties. An H21 project report[29] suggested a proportion of these could require replacement due to the higher volumetric flows of hydrogen required to supply a given amount of energy. There is significant uncertainty around this issue, and it has been suggested that many of these works could be avoided by various network level solutions, however this could have significant implications for customers. An estimated range of service pipe replacements for Cornwall is 79,000 to 83,000 across all three scenarios.

Medium, intermediate and high-pressure networks

Each scenario explored has an associated 'Bill of Quantities', indicating the quantity of infrastructure needed, summarised in Figure 142. This is the same for all three scenarios in Cornwall, discussed in section 7. Values are given as a percentage of the length of currently existing network for each respective pressure tiers – these are of 160km for the HP network, 106km for the IP network, and 423km of MP network.

In modelling the transition of networks from the network as it is today to one indicative of that required to serve the 2050 scenarios, the method re-purposes as much of the existing natural gas network for hydrogen service as possible. This was done whilst considering the need to maintain a natural gas supply through the transition and practical switching constraints of connections dependent on a natural gas supply to one receiving hydrogen. The result is an increased quantity of repurposing that is considered generous and reduced amount of new hydrogen. Transition of gas networks is recognised as a highly complex process and further analysis is required to fully understand the influencing factors to inform decisions. The detail of the modelling logic is provided in section 7.

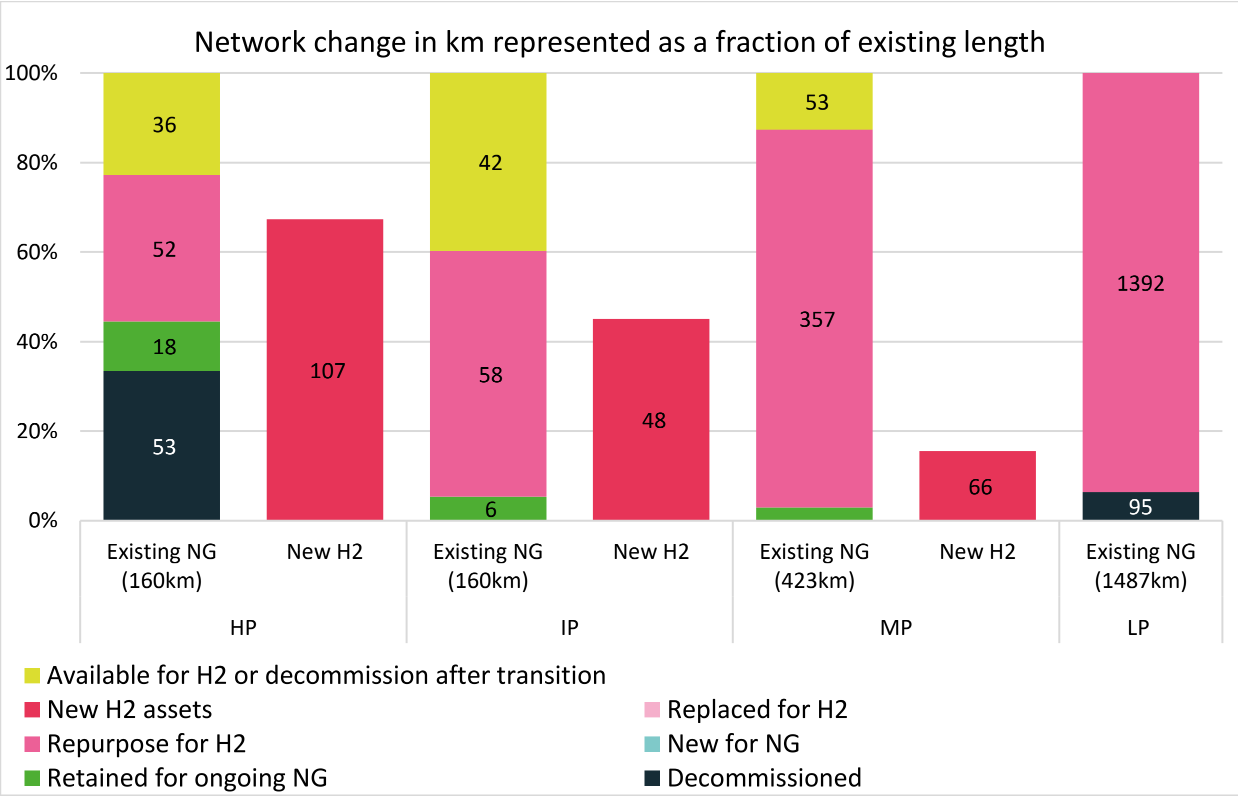


Figure 142: Network changes as a percentage of existing pressure tier length

Medium Pressure

Less than 3% of the length of the currently existing MP network is indicated as serving natural gas in 2050. The assets used for this purpose are the last few tens of meters between higher pressure tier pipelines, and industrial demand sites. 13% of the MP network is required where the number of connections exceeded the modelling threshold, see section 4 for details, for transition. These assets will be made available to reinforce hydrogen network or for decommission by 2050, and further studies (e.g., flow analysis) should inform the distinction between these possible outcomes.

The remaining MP network (84%) could be "repurposed for hydrogen service", mostly because – as opposed to the above – these assets are not the unique possible route serving the volume of connections below the threshold. Rather, a typical section of such MP network provides one of many routes for gas to flow into a connected region of LP network. Subject to the caveats given above, this redundancy may allow for the repurposing of these existing assets by sectors during the transition, negating the need for new hydrogen assets along similar routes (see section 4 for further details).

Intermediate Pressure

A large section of the IP network in Cornwall corresponds to extensions of the HP network, as linear stretches of pipes reaching MP networks. As a result, a high proportion of the existing IP network (40%) could be "Available for H2 or decommission after transition", due to the high dependencies on these network sections. Around 5% of the IP network is retained on natural gas in order to supply ongoing demand out to 2050.

Where none of the above constraints apply, for 55% of the existing network, the assets are repurposed to hydrogen service. As a result, the need for entirely new hydrogen IP pipelines corresponds to about 45% of the existing network length.

High Pressure

33% of the HP network in Cornwall are vintage pipelines, leading to decommissioning of these assets by 2050. 34% of the HP network corresponds to assets retained on natural gas supply either in order to supply the industrial site with ongoing demand out to 2050 (11%), or temporarily due to transitional needs (23%) – such assets will be available for network reinforcement, storage or decommission by 2050. Assets in the category "Available for H2 or decommission after transition" represent a lower proportion of the HP network than in the IP network. This is because, as the representation of the HP network visible on Figure 140 shows, there is a long stretch of parallel pipelines from the offtake near Plymouth to Redruth. This provides some flexibility for the transition and enables more of the existing network to be used for transition.

The remaining 33% of the HP network are repurposed for hydrogen supply, leading to the need for new hydrogen pipelines with a total length equivalent to nearly 70% of the existing network (102km).

25.5. CONCEPTUAL PLAN

The Conceptual Sub Regional Pull Outs are based on engineering analysis which considers the implications of the scenarios for natural gas and hydrogen infrastructure. This provides a basis to understand the decisions which are required around investment in network infrastructure to support decarbonisation and, provide an indicative illustration of the uptake of conversion of Domestic and Commercial meters to hydrogen between 2020 and 2050, across the three scenarios

25.5.1. INSIGHTS SUMMARY – CORNWALL

- Hydrogen will potentially be produced to feed major emitters in the Plymouth area and Cornwall will be a net importer of Hydrogen, from the North.
- Potential to Repurpose: The majority of the LTS system in Devon (Figure 58) was constructed from pipe material strength grade of X52 and below. These pipe materials are suited to the transportation of hydrogen however, where pipelines have been constructed of higher strength grade then further work may be required to be undertaken prior to conversion to confirm their suitability. There are also a number of sections of the LTS network in this area which are over fifty years old and may potentially reach the end of the pipelines useable life shortly. Some of these older pipelines may also have been used for Towns Gas service, which can also suffer from further degradation due to the effect of hydrogen on the pipe wall. Where these pipelines are to be replaced then it is recommended that they are replaced with pipelines suitably sized and with a pipe material grade which suitable for hydrogen service.
- For all three scenarios in the Cornwall approximately 92-93% (Section 10 ESC of the Domestic and Commercial gas meters are estimated to be retained in 2050.

Table 38. Cornwall Meters Converted per 5 Year Cycle

Cornwall	Number of Meters Converted per 5 Year Cycle						
	2020	2025	2030	2035	2040	2045	2050
High Electrification	0	0	0	0	1002	1094	0
Balanced	0	0	0	0	1344	822	0
High Hydrogen	0	0	0	0	1308	858	0

It can be seen from Table 38 that under the all three scenarios conversion starts circa 2040. The workforce size requirements is also similar for all three scenarios.

- Due in part to the high retention of the Domestic and Commercial customer base, all three scenarios in Cornwall will require similar levels of new pipeline infrastructure to enable conversion to hydrogen. In total approximately 72.6 km of new high pressure LTS hydrogen pipeline would be required in Cornwall by 2045.

Table 39. Cornwall KM of New Hydrogen Pipeline per 5 Year Cycle

Cornwall	KM of New Hydrogen Pipeline per 5 Year Cycle						
	2020	2025	2030	2035	2040	2045	2050
All Scenarios	0	0	0	0	72.6	0	0

Table 25. South Wales KM of New Hydrogen Pipeline per 5 Year CycleTable 39 details an indicative level of the length of new hydrogen pipeline required in a particular 5 year cycle.

25.5.2. BALANCED (BAL)

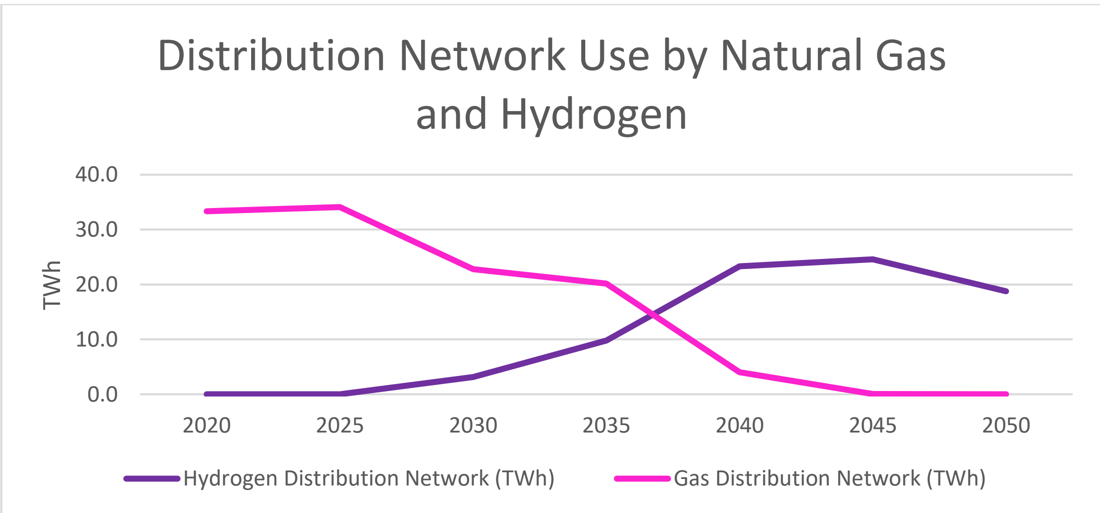
There are no offtakes from the Gas Transmission system in Cornwall, the meter analysis is therefore based on the nearest offtake located in Devon. Table 18 shows the forecast hydrogen production and, distribution network consumption of natural gas and hydrogen for the Balanced (BAL) WWU scenario modelled in ESME in the South West. It can be seen that Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Initially hydrogen is supplied to industrial users and starts to be supplied to the distribution system before 2030 with the system supplying the maximum predicted hydrogen demand in 2045. Before consumption drops away towards 2050. Conversion of the Distribution Network is completed shortly after 2040.

Table 40. South West Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

South West	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.0	0.0	4.7	14.3	15.0	13.9	13.9
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	3.2	9.8	23.3	24.6	18.8
Natural Gas Consumption from Distribution Network (TWh)	33.4	34.1	22.8	20.1	4.0	0.0	0.0

Figure 143 South West Distribution Network Use by Natural Gas and Hydrogen – Balanced



As detailed in Section 10, a small number of larger emitters in Cornwall. The decisions taken by these emitters to decarbonise their emissions may have an impact on the energy transition solutions deployed in Cornwall. Figure 144 shows the NAEI Sector and Emission Tonnage for the major emitters of carbon dioxide in Cornwall.

Figure 144 Cornwall - NAEI Large Emitters By Sector and Emissions Tonnage

Table 41. Cornwall Meters Converted per 5 Year Cycle – Balanced

South West	Number of Meters Converted per 5 Year Cycle – Balanced						
	2020	2025	2030	2035	2040	2045	2050
Choakford	0	0	0	0	156148	0	0
Total	0	0	0	0	156148	0	0
Meters Converting per Week (40 Wks/Year)	0	0	0	0	781	0	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

Figure 145 2040 – 2050 Balanced - Domestic and Commercial Meters

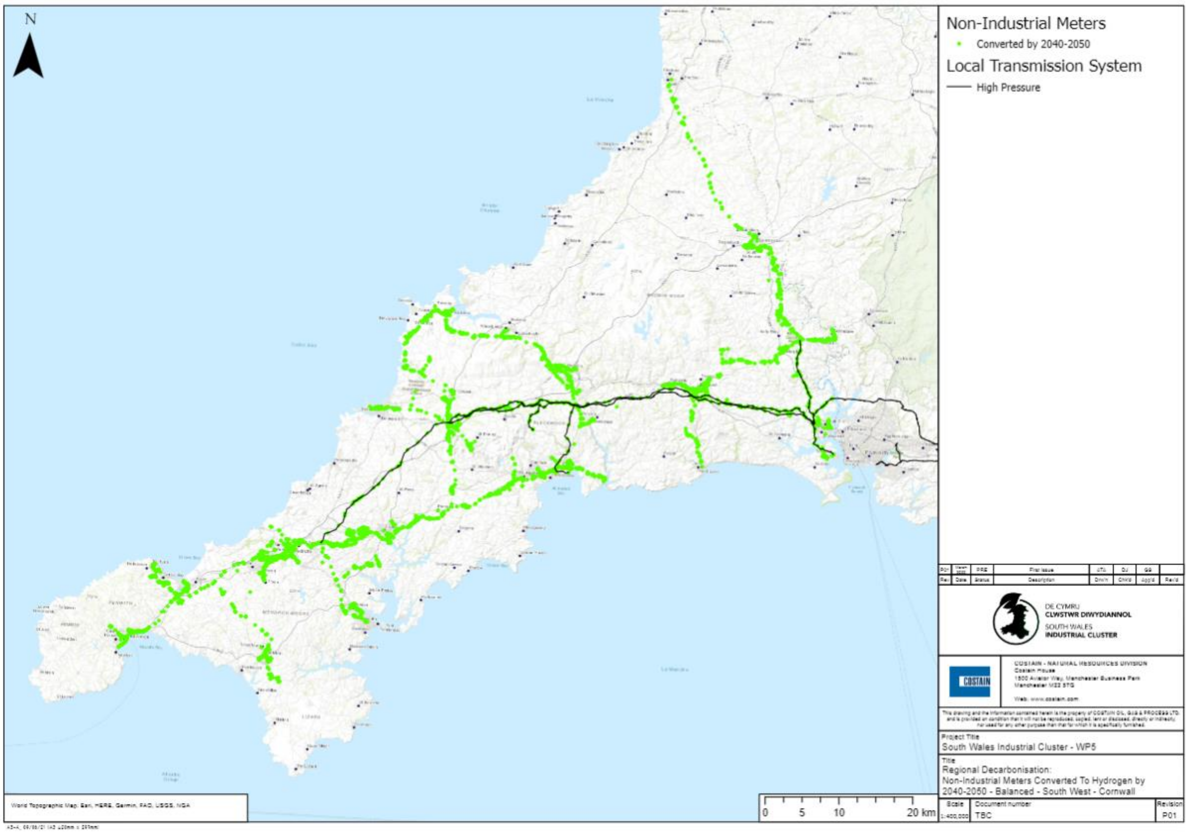
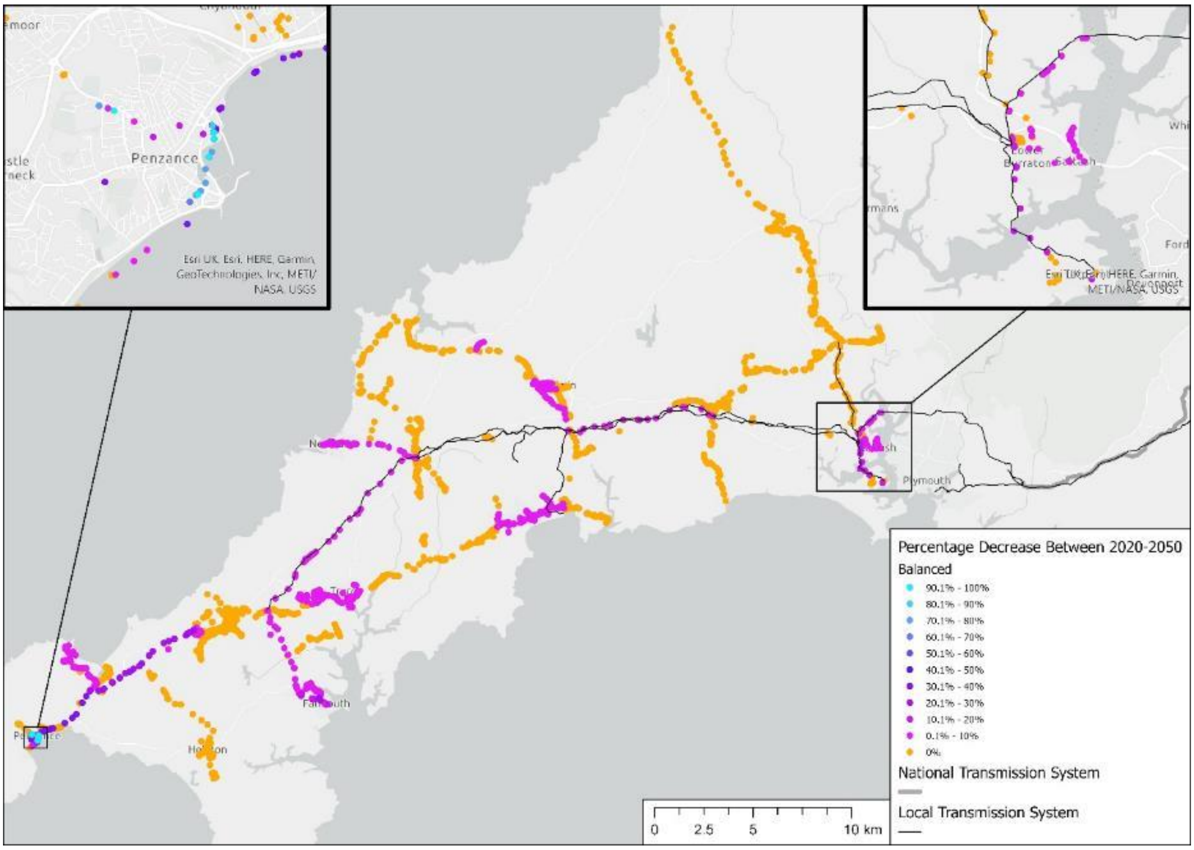


Figure 146 % Change in the Domestic and Commercial Meters – Balanced in 2050



Under the Balanced scenario there will be an approximate 16% reduction in the number of non dependent meters. Figure 146 details the areas where there is predicted to be a fall in the number of customers on the gas system. A higher proportion of meters are lost in the centre of a number of the major conurbations, where district heating takes over as the source of domestic heat load.

25.5.3. COMPARISON OF THE THREE SCENARIOS

According to the ESME Whole System Overview (Section 6.2), for all three scenarios hydrogen production ramps up and peaks in similar timescales. Production of hydrogen and hydrogen consumption from the distribution network are broadly similar for High hydrogen (101% of Balanced). However, in the High electrification case, production of hydrogen and hydrogen consumption from the distribution network is lower than the Balanced scenario (73% of Balanced). As can be seen from Figure 14.48, there are falls in the number of domestic meters in the major conurbations and this is broadly reflected across all three scenarios.

The quantity of new pipeline required will be similar across all three scenarios, due in part to the requirements for the system to be able to supply peak demand. However, for the High Electrification case, pipeline diameters may be slightly smaller than those required for the High Hydrogen and Balanced scenarios.

Details of the Conceptual Plan analysis of Electrification and High Hydrogen scenarios can be found in Section E.

SECTION E: ADDITIONAL SCENARIO MAPS

26. SUB-REGIONAL PLANS (ELE / BAL / HYD) - WALES

26.1. NORTH WALES

26.1.1. HIGH ELECTRIFICATION (ELE)

In the High Electrification (ELE) WWU scenario modelled in ESME, hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 26.1. ELE Hydrogen Production Capacity and Gas Distribution Consumption

	Year						
	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.4	0.7	1.0	10.4	37.4	34.1	26.0
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	0.0	2.1	9.8	5.6	4.4
Natural Gas Consumption from Distribution Network (TWh)	13.0	15.5	12.4	8.2	0.4	0.0	0.0

Figure 26.1. ELE Wales Distribution Network Use by Natural Gas and Hydrogen

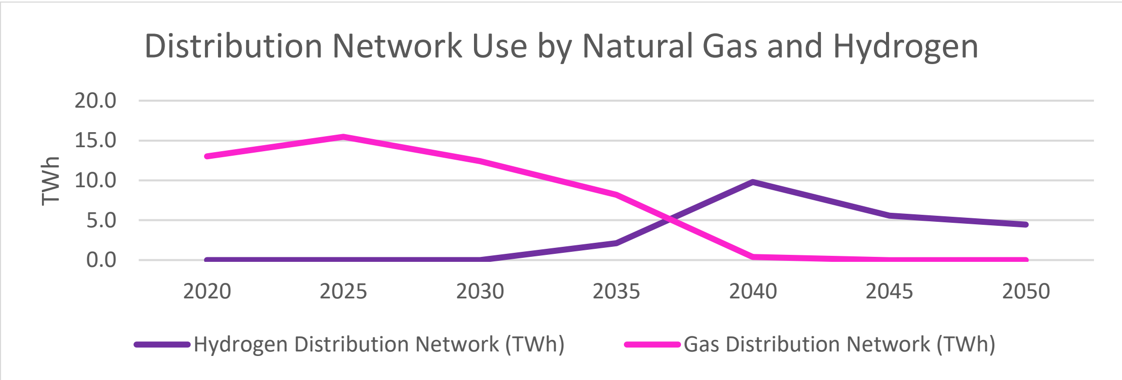


Table 26.2. ELE North Wales Meters Converted per 5 Year Cycle

	Year						
	2020	2025	2030	2035	2040	2045	2050
Total - Maelor Coast	0	0	0	157,888	47,222	0	0
Meters Converting per Week (40 Wks/Year)	0	0	0	789	236	0	0

It should be noted that the number of meters requiring conversion each week is based on the assumption that conversion will take place outside the peak winter demand supply period, i.e. over 40 weeks per year (March to November).

Figure 26.2. ELE Scenario 2020 – 2030 – Non-Industrial Meters

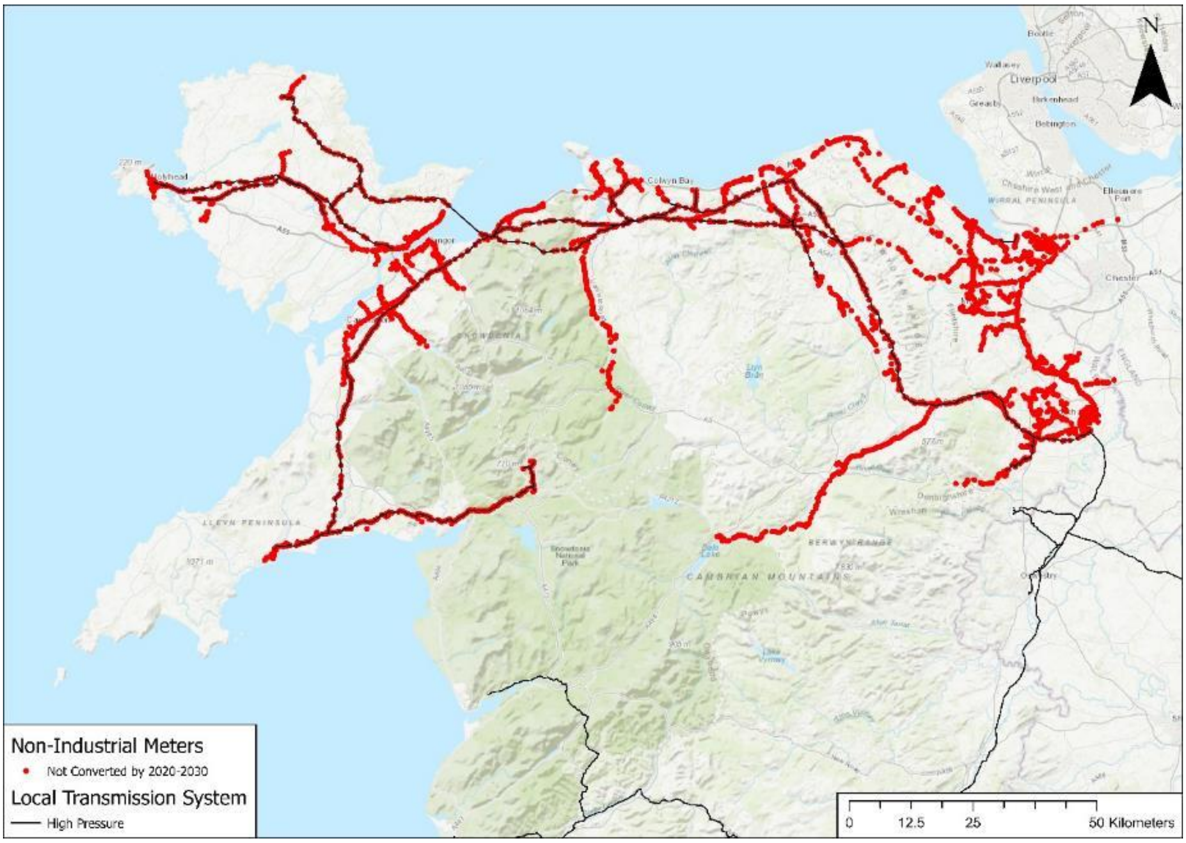


Figure 26.3. ELE Scenario 2035 – Non-Industrial Meters

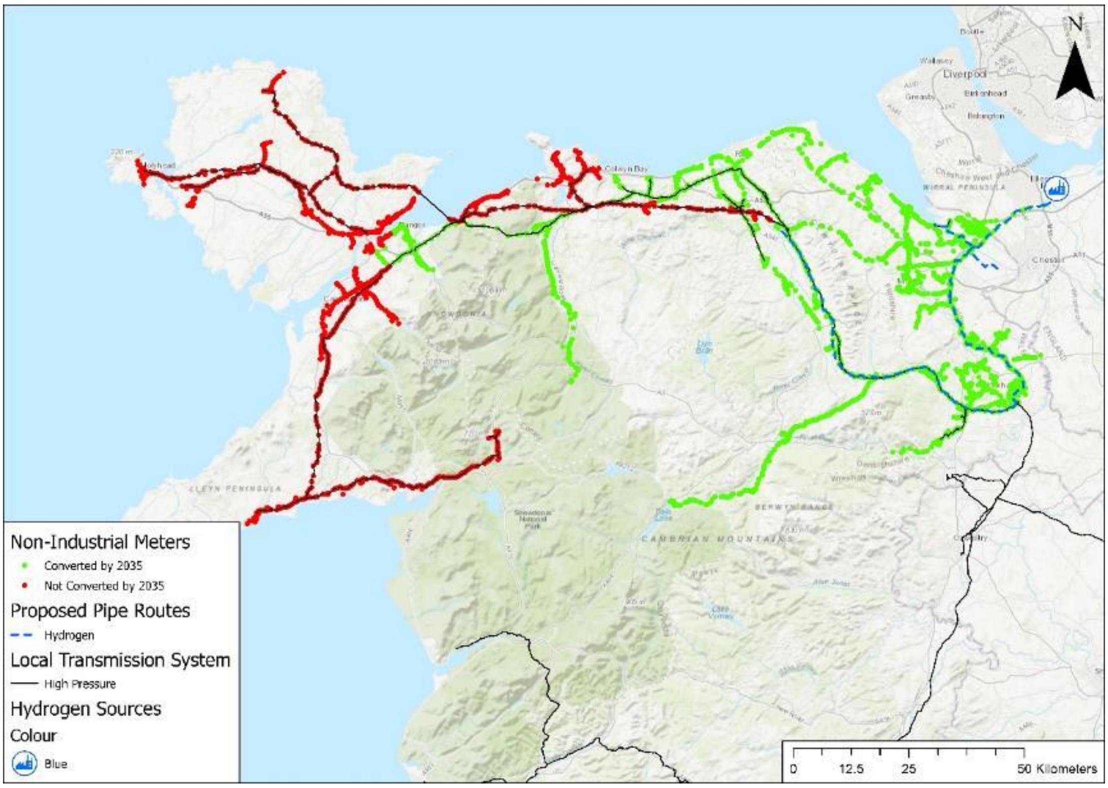


Figure 26.4. ELE Scenario 2040 – 2050 – Non-Industrial Meters

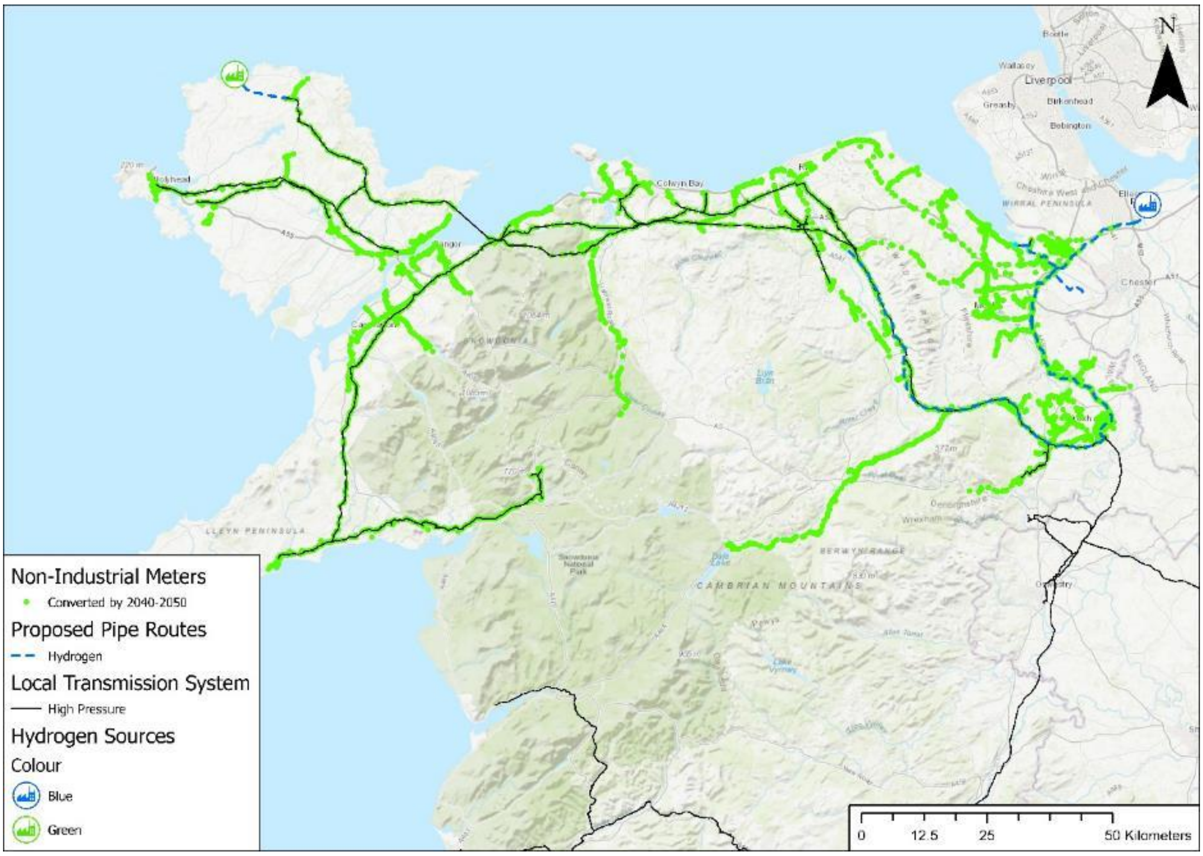
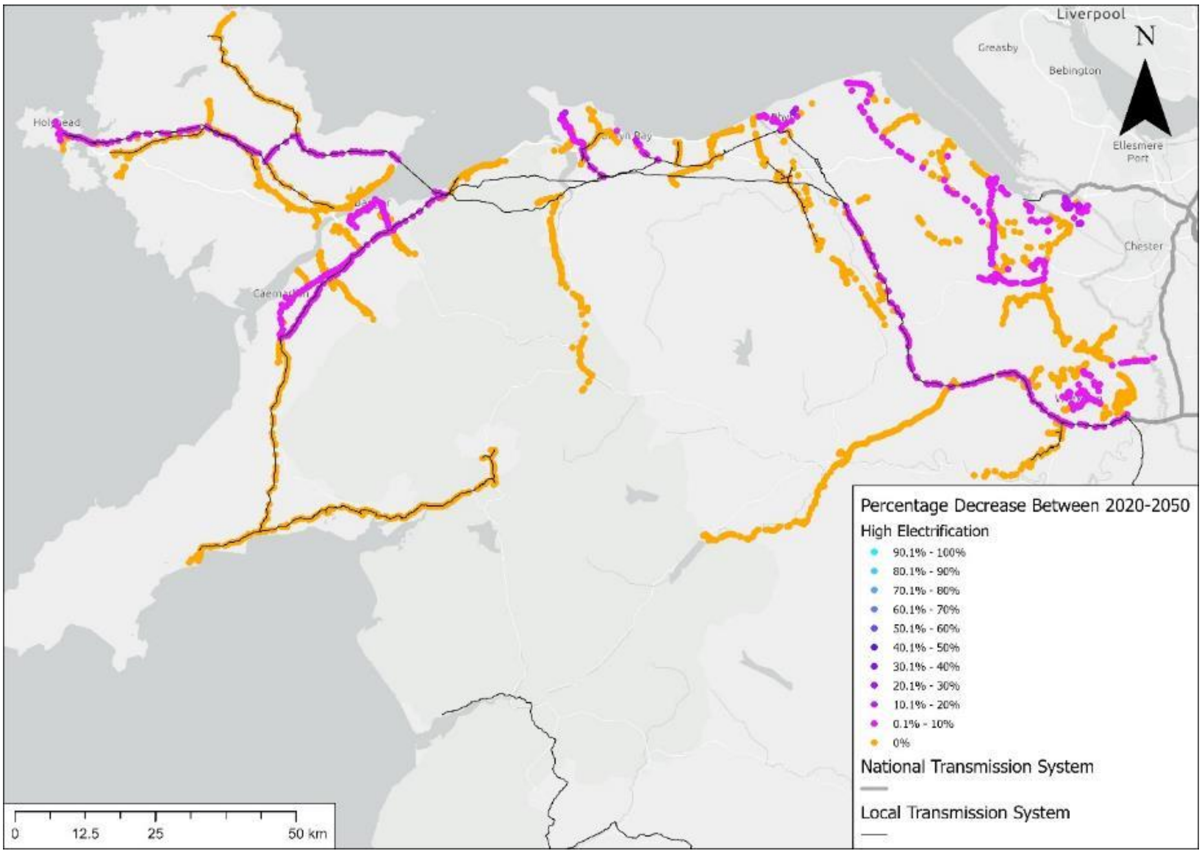


Figure 26.5. ELE Scenario 2050 - Change in the Non-Industrial Meters



26.1.2. BALANCED (BAL)

According to the Balanced (BAL) WWU scenario modelled in ESME, hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

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Table 26.3. BAL Hydrogen Production Capacity and Gas Distribution Consumption

	Year						
	2020	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Total Hydrogen Production (TWh)	0.8	1.2	5.9	11.3	47.8	42.2	33.4
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	2.6	5.2	13.5	13.7	11.7
Natural Gas Consumption from Distribution Network (TWh)	11.9	15.1	9.3	9.8	1.9	0.0	0.0

Figure 26.6. BAL Wales Distribution Network Use by Natural Gas and Hydrogen

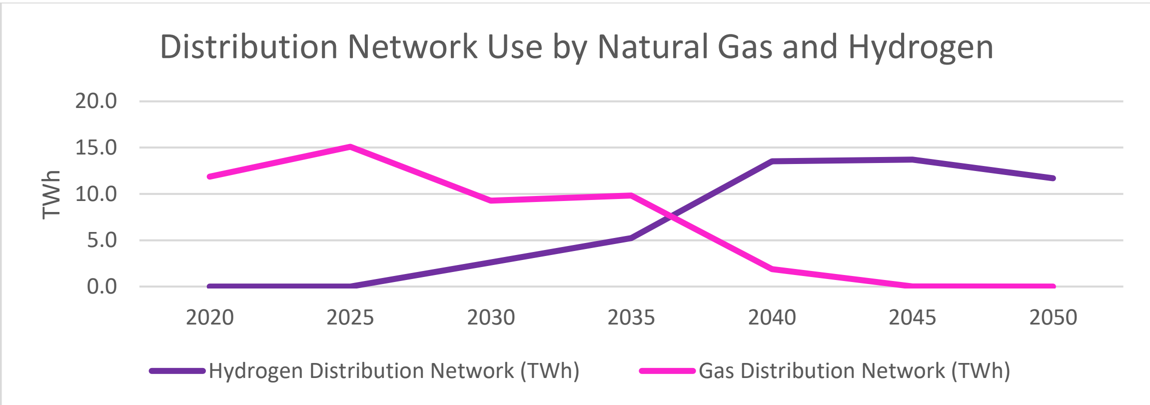


Table 26.4. BAL North Wales Meters Converted per 5 Year Cycle

	Year						
	2020	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Total - Maelor Coast	0	0	54,291	91,389	59,483	0	0
Meters Converting per Week (40 Wks/Year)	0	0	271	457	297	0	0

It should be noted that the number of meters requiring conversion each week is based on the assumption that conversion will take place outside the peak winter demand supply period i.e. over 40 weeks per year (March to November).

Figure 26.7. BAL Scenario 2020 – 2025 – Non-Industrial Meters

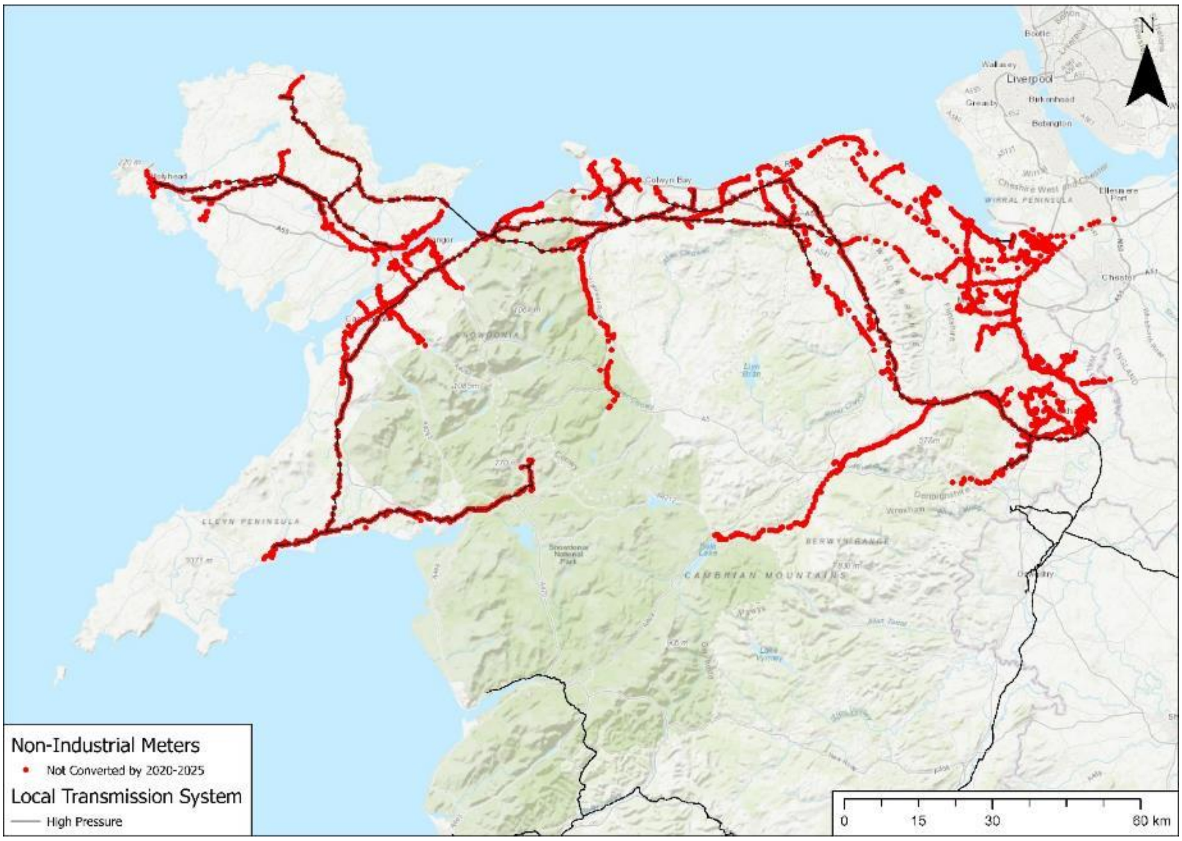


Figure 26.8. BAL Scenario 2030 – Non-Industrial Meters

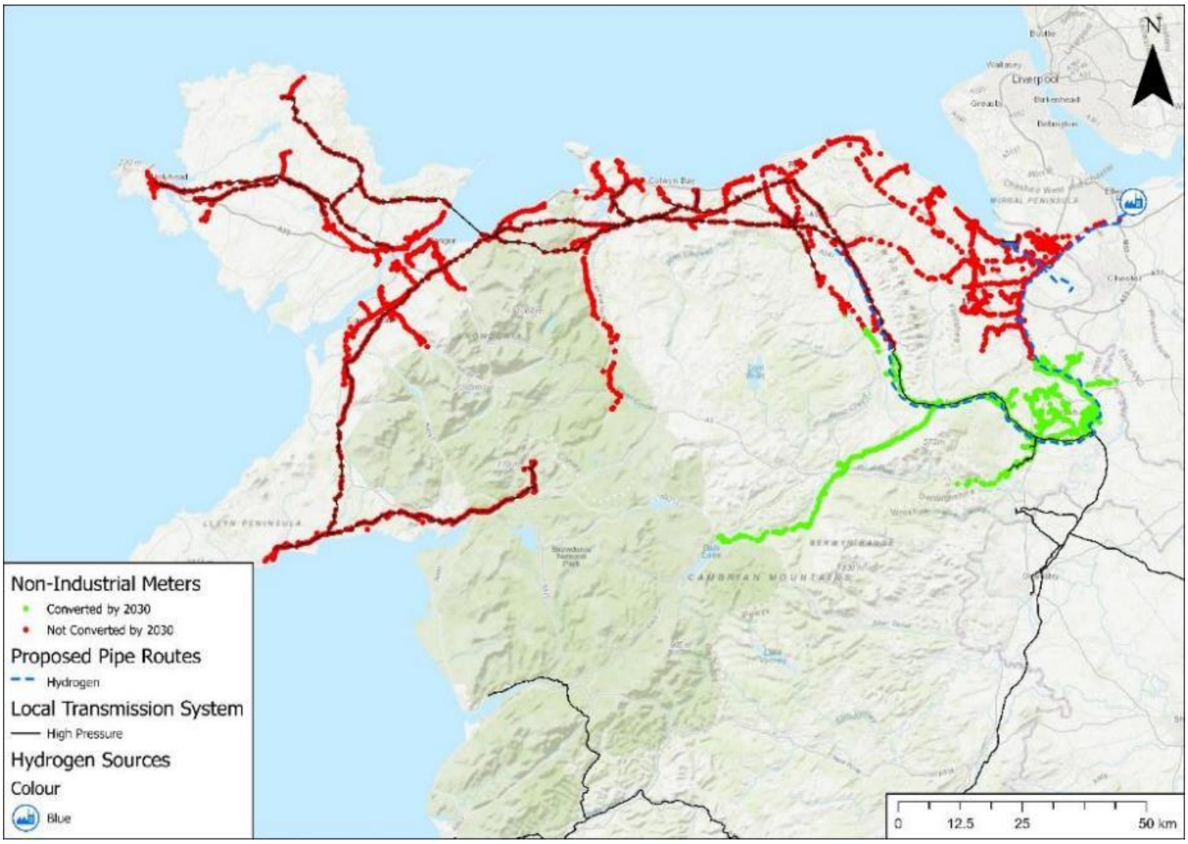


Figure 26.9. BAL Scenario 2035 – Non-Industrial Meters

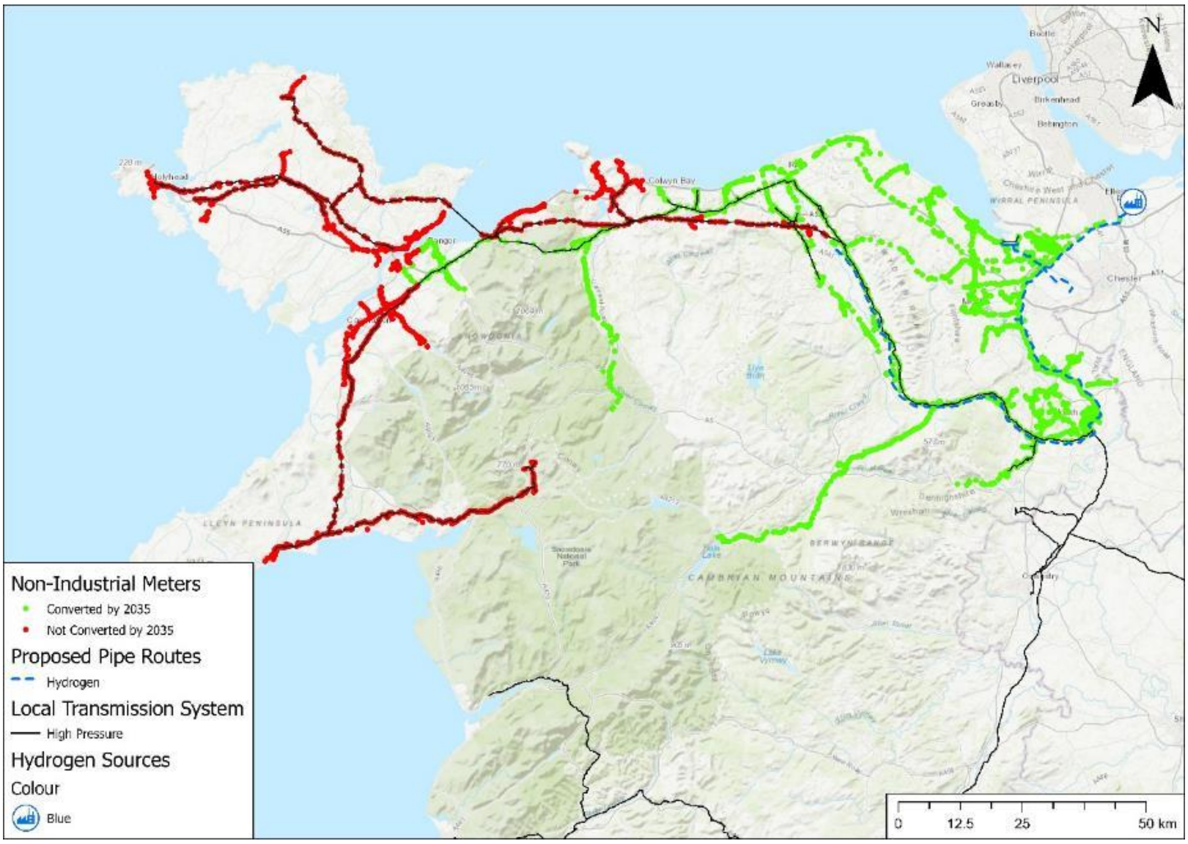


Figure 26.10. BAL Scenario 2040 – 2050 – Non-Industrial Meters

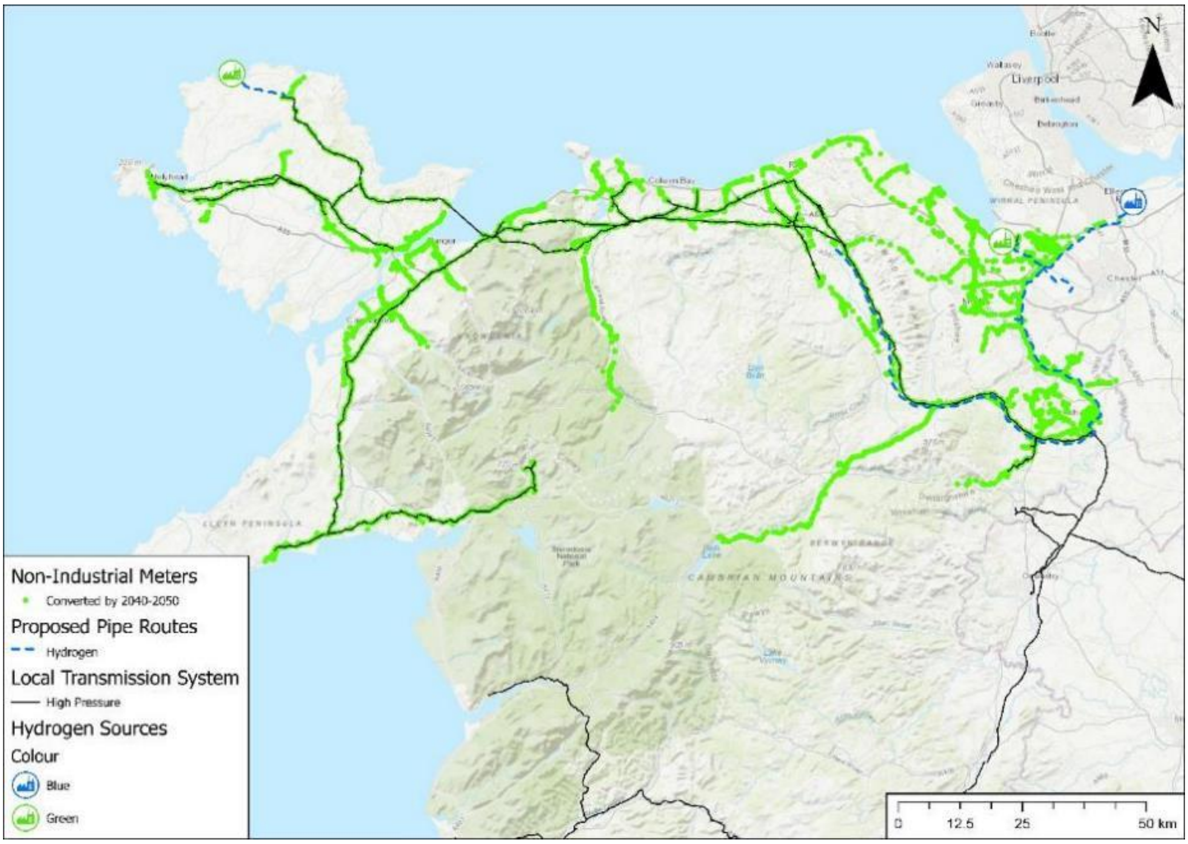
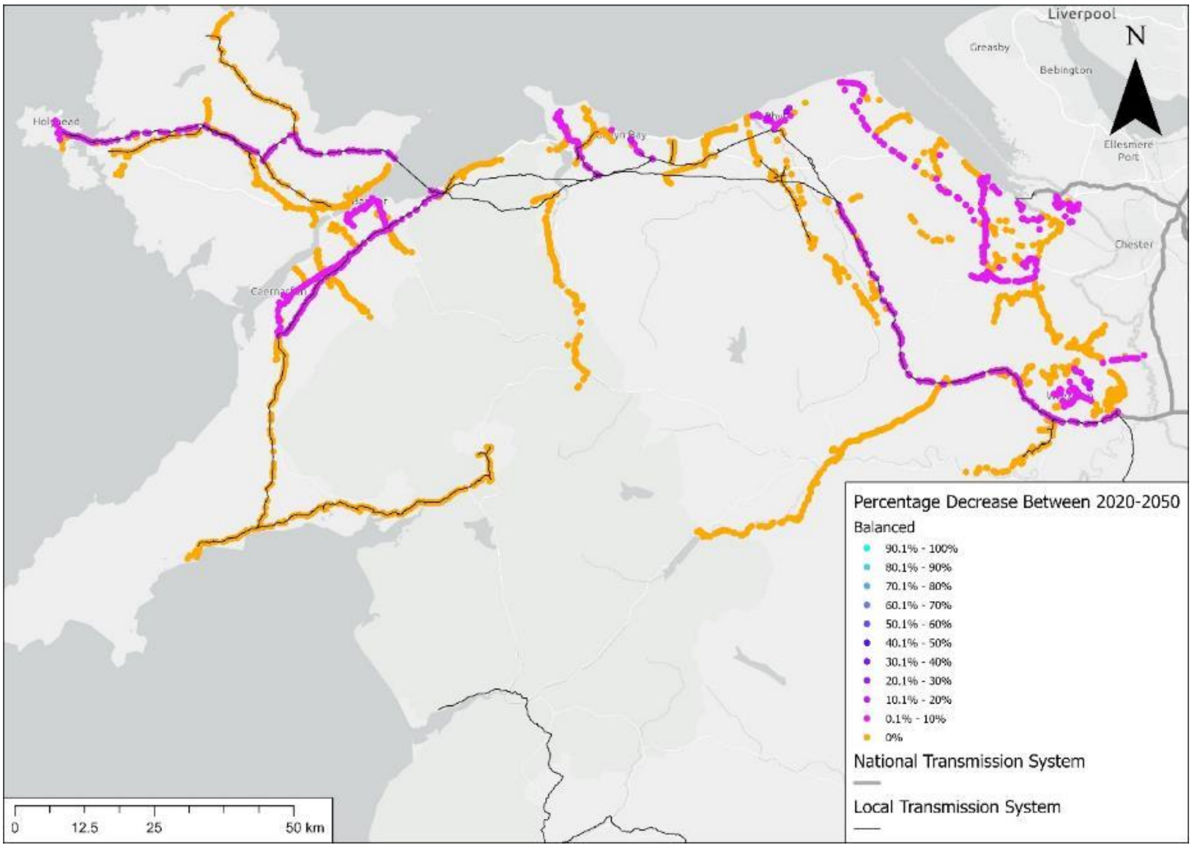


Figure 26.11. BAL Scenario 2050 - Change in the Non-Industrial Meters



26.1.3. HIGH HYDROGEN (HYD)

According to the High Hydrogen (HYD) WWU scenario modelled in ESME, hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 26.5. HYD Hydrogen Production Capacity and Gas Distribution Consumption

	Year						
	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.6	1.1	4.6	10.8	54.0	50.0	40.1
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	2.2	5.4	14.2	14.7	12.4
Natural Gas Consumption from Distribution Network (TWh)	11.8	15.2	9.9	10.5	2.1	0.0	0.0

Figure 26.12. HYD Wales Distribution Network Use by Natural Gas and Hydrogen

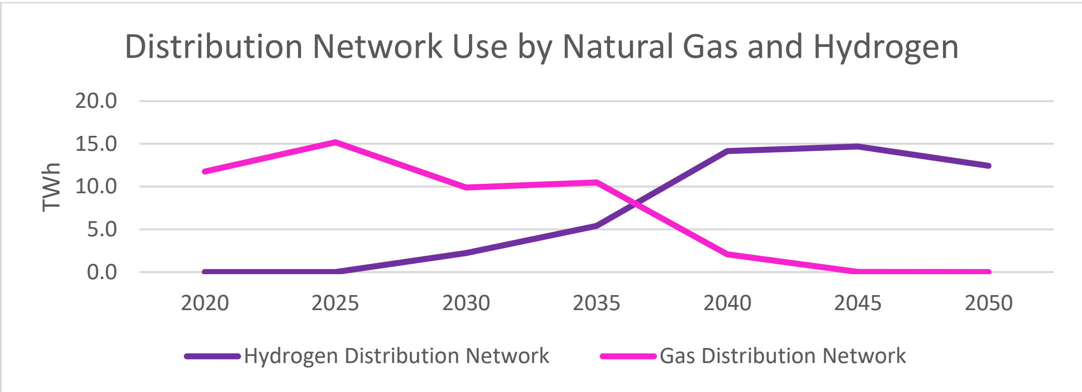


Table 26.6. HYD North Wales Meters Converted per 5 Year Cycle

	Year						
	2020	2025	2030	2035	2040	2045	2050
Total - Maelor Coast	0	0	20,000	111,803	66,050	9,136	0
Meters Converting per Week (40 Wks/Year)	0	0	100	559	330	46	0

It should be noted that the number of meters requiring conversion each week is based on the assumption that conversion will take place outside the peak winter demand supply period, i.e. over 40 weeks per year (March to November).

Figure 26.13. HYD Scenario 2020 – 2025 – Non-Industrial Meters

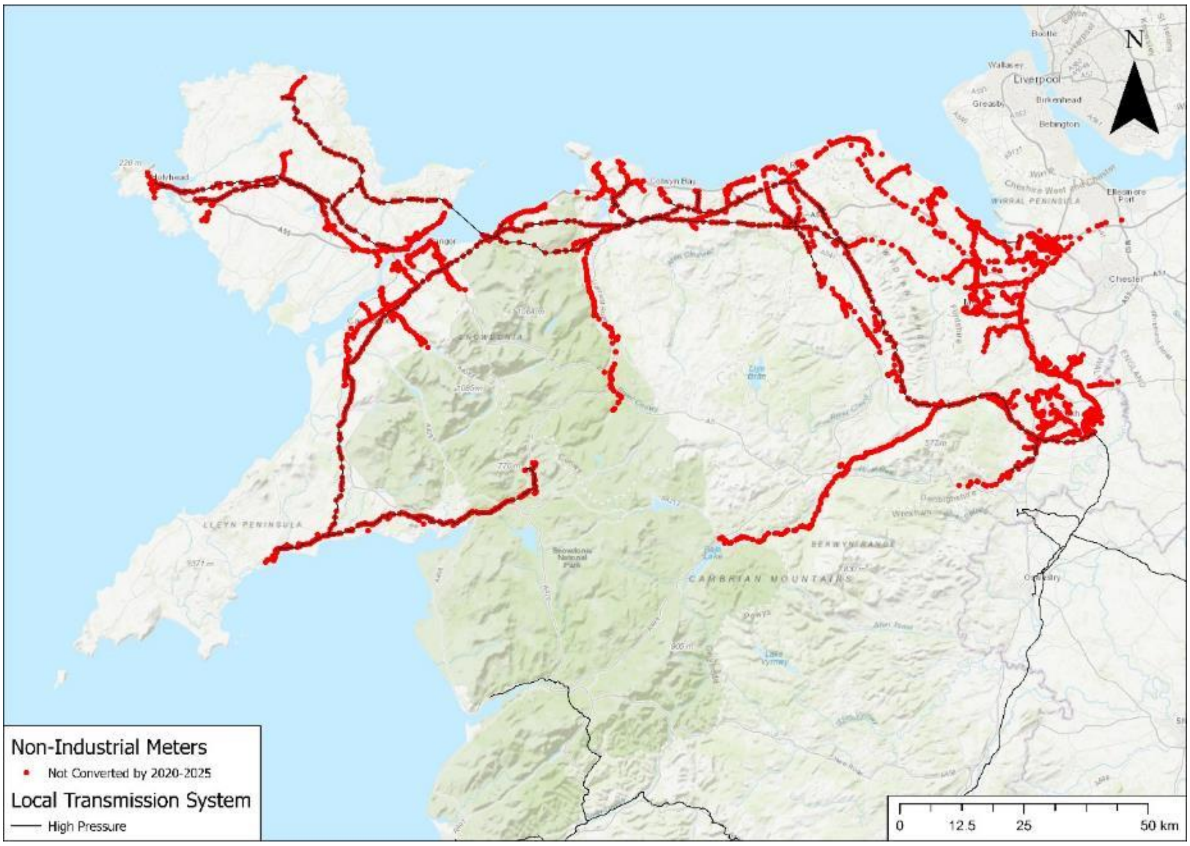


Figure 26.14. HYD Scenario 2030 – Non-Industrial Meters

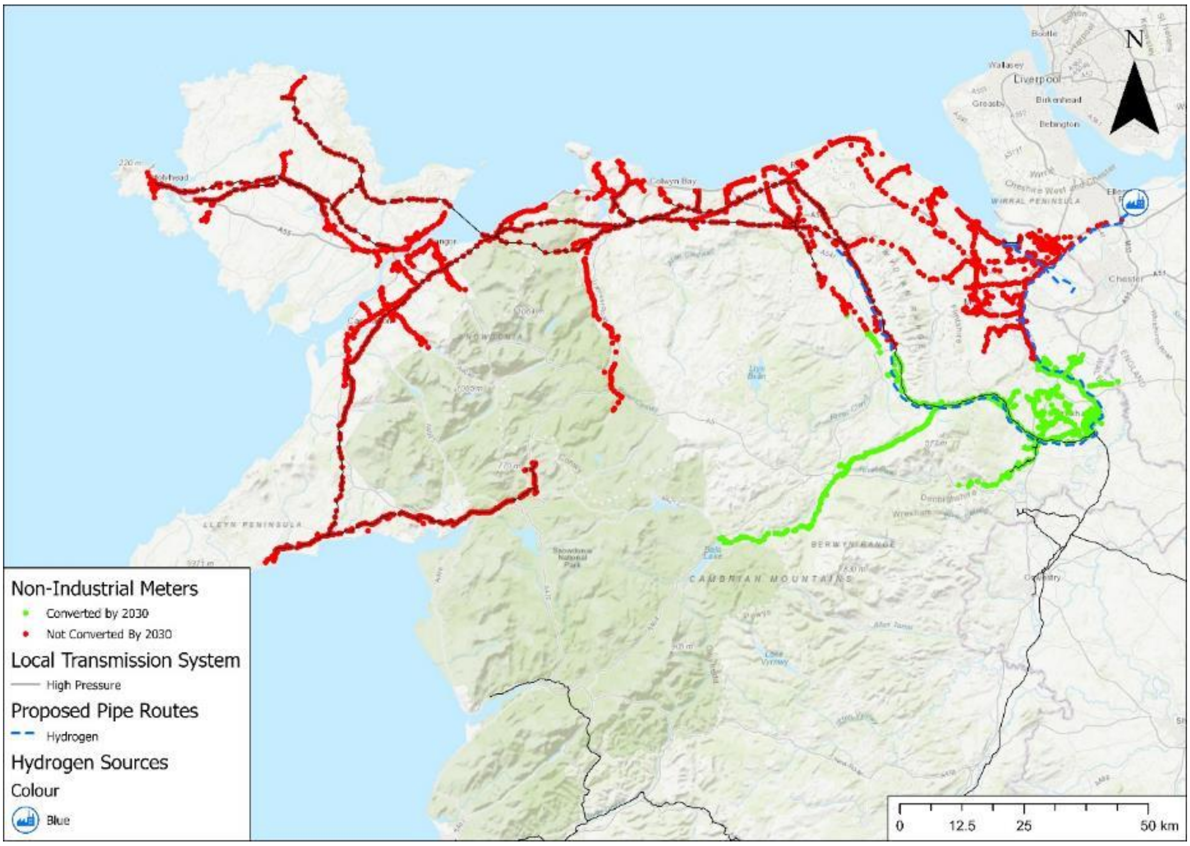


Figure 26.15. HYD Scenario 2035 – Non-Industrial Meters

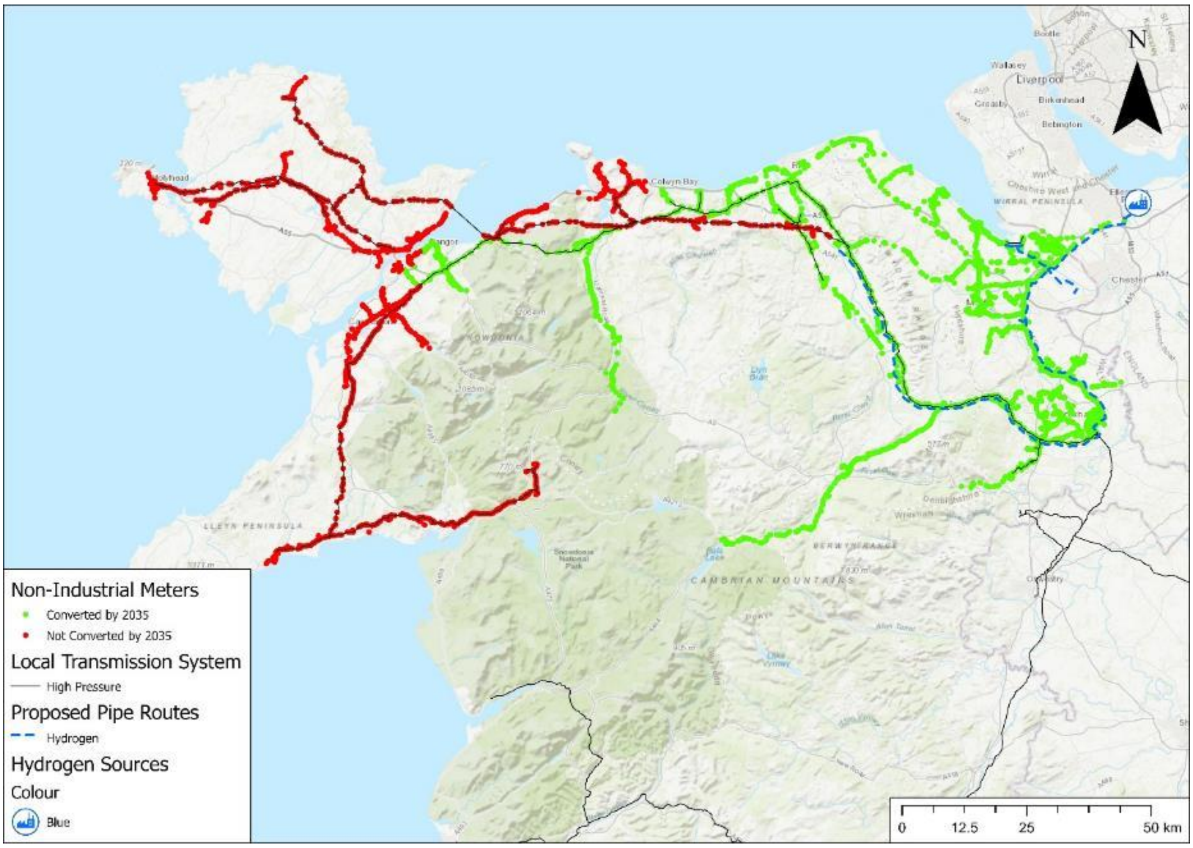


Figure 26.16. HYD Scenario 2040 – Non-Industrial Meters

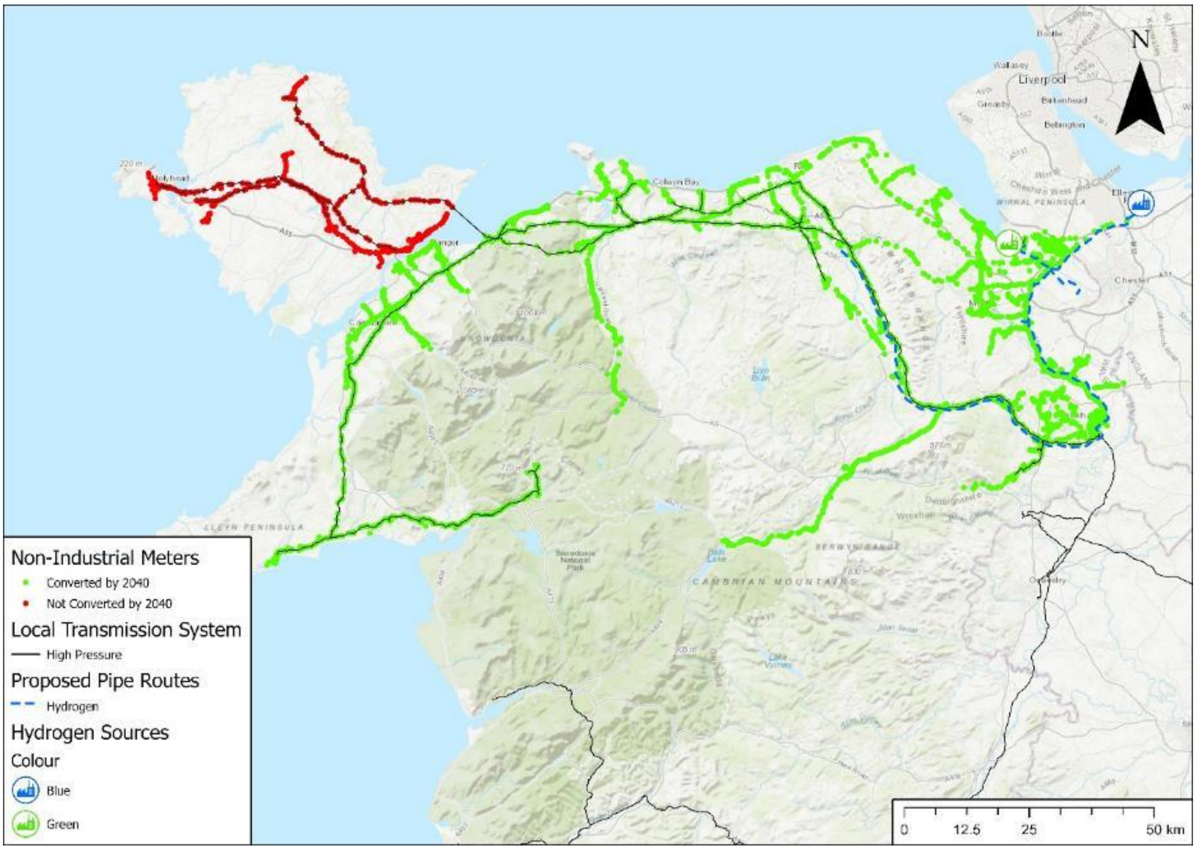


Figure 26.17. HYD Scenario 2045 – 2050 – Non-Industrial Meters

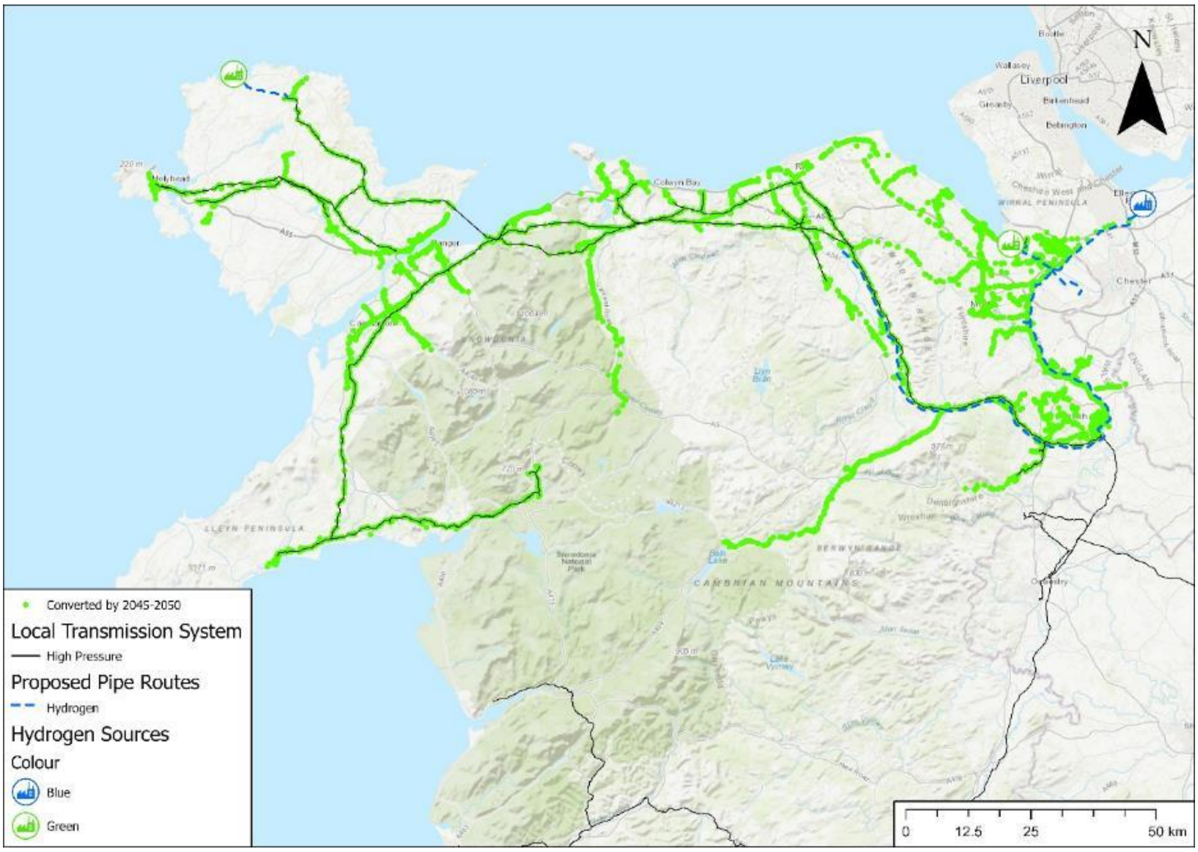
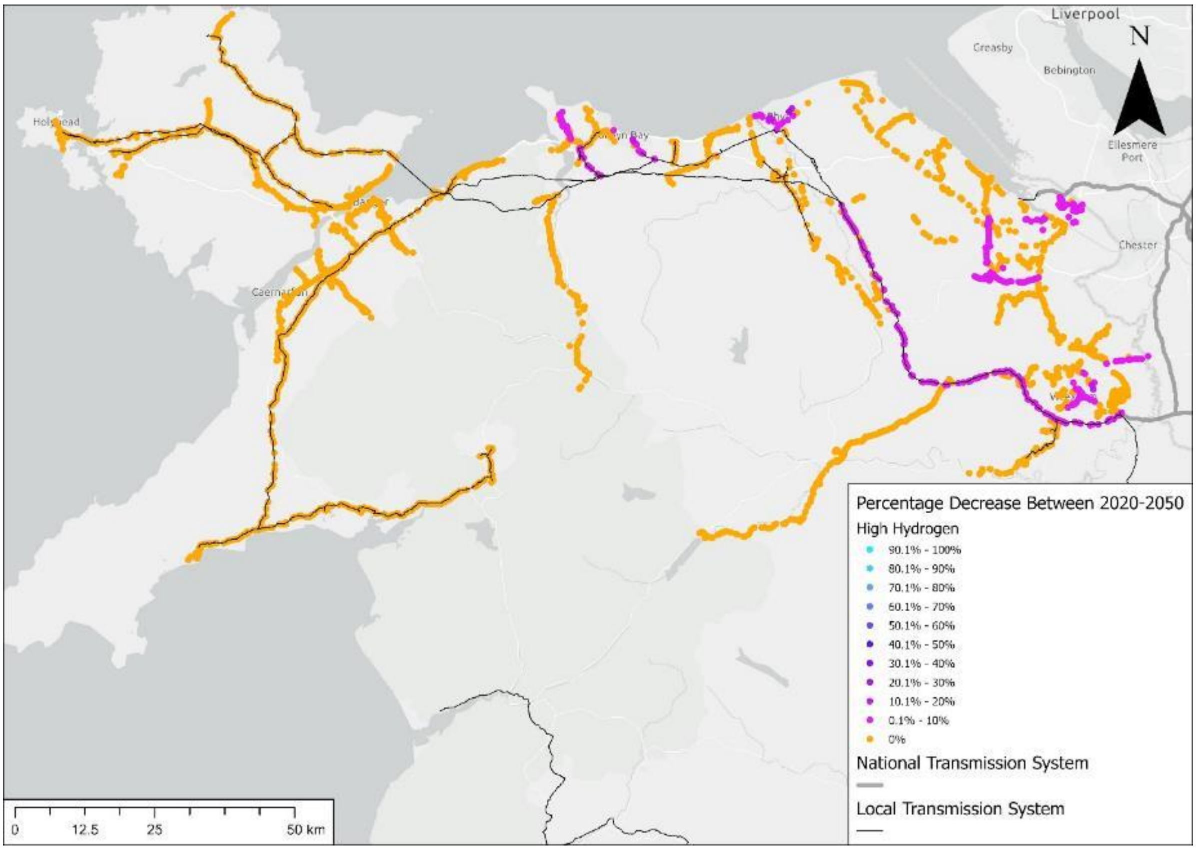


Figure 26.18. HYD Scenario 2050 - Change in the Non-Industrial Meters



26.1. MID WALES

26.1.1. HIGH ELECTRIFICATION (ELE)

According to the High Electrification (ELE) WWU scenario modelled in ESME Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

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Table 26.7. Wales Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

Wales	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.4	0.7	1.0	10.4	37.4	34.1	26.0
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	0.0	2.1	9.8	5.6	4.4
Natural Gas Consumption from Distribution Network (TWh)	13.0	15.5	12.4	8.2	0.4	0.0	0.0

Figure 26.19. Wales Distribution Network Use by Natural Gas and Hydrogen – High Electrification

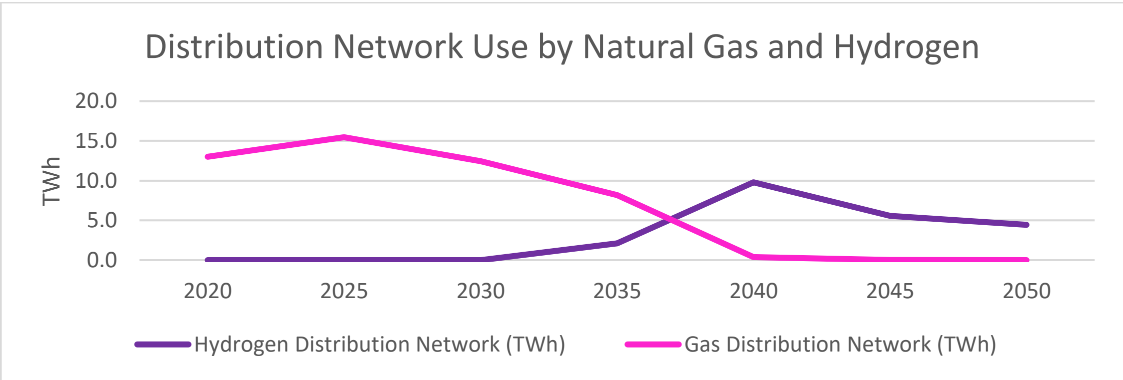


Table 26.8. Mid Wales Meters Converted per 5 Year Cycle – High Electrification

Mid Wales	Number of Meters Converted per 5 Year Cycle – High Electrification						
	2020	2025	2030	2035	2040	2045	2050
Maelor Mid	0	0	0	0	51278	0	0
Meters Converting per Week (40 Wks/Year)	0	0	0	0	256	0	0

It should be noted that the number of meters requiring conversion each week is based on the assumption that conversion will take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

Figure 26.20. 2020 – 2030 High Electrification - Domestic and commercial Meters

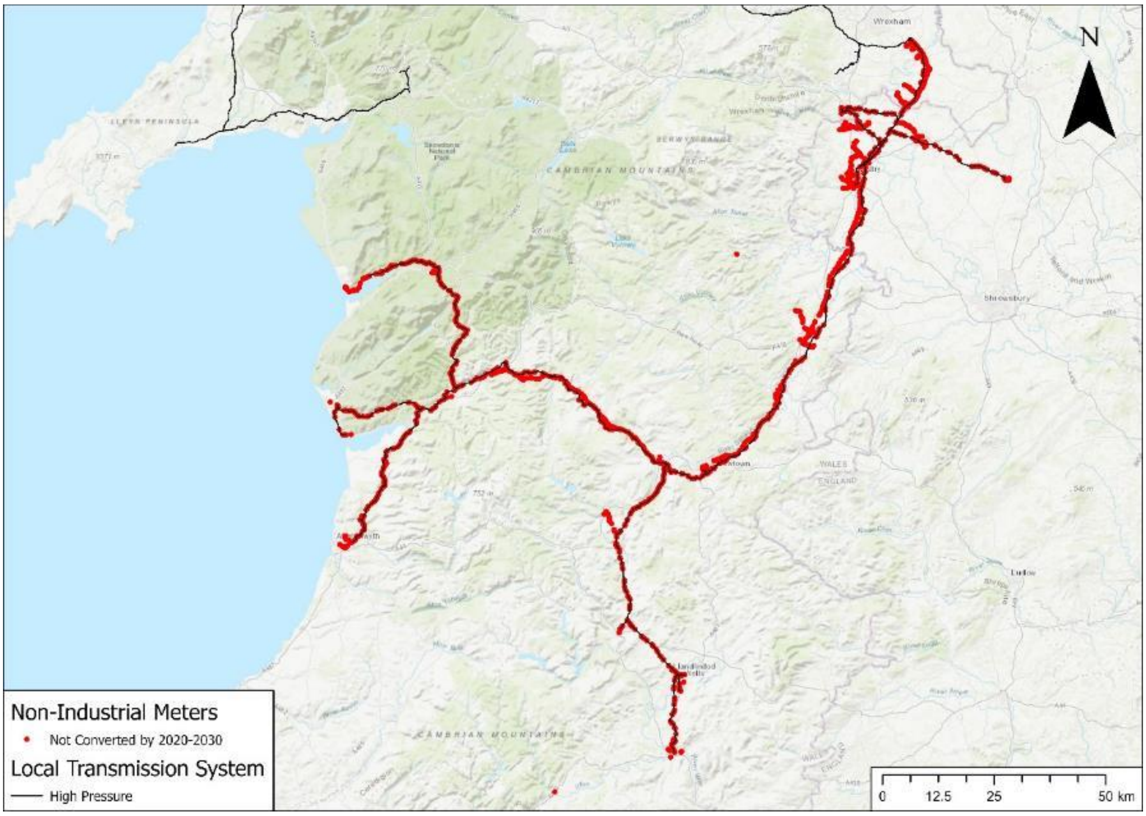


Figure 26.21. 2035 High Electrification - Domestic and commercial Meters

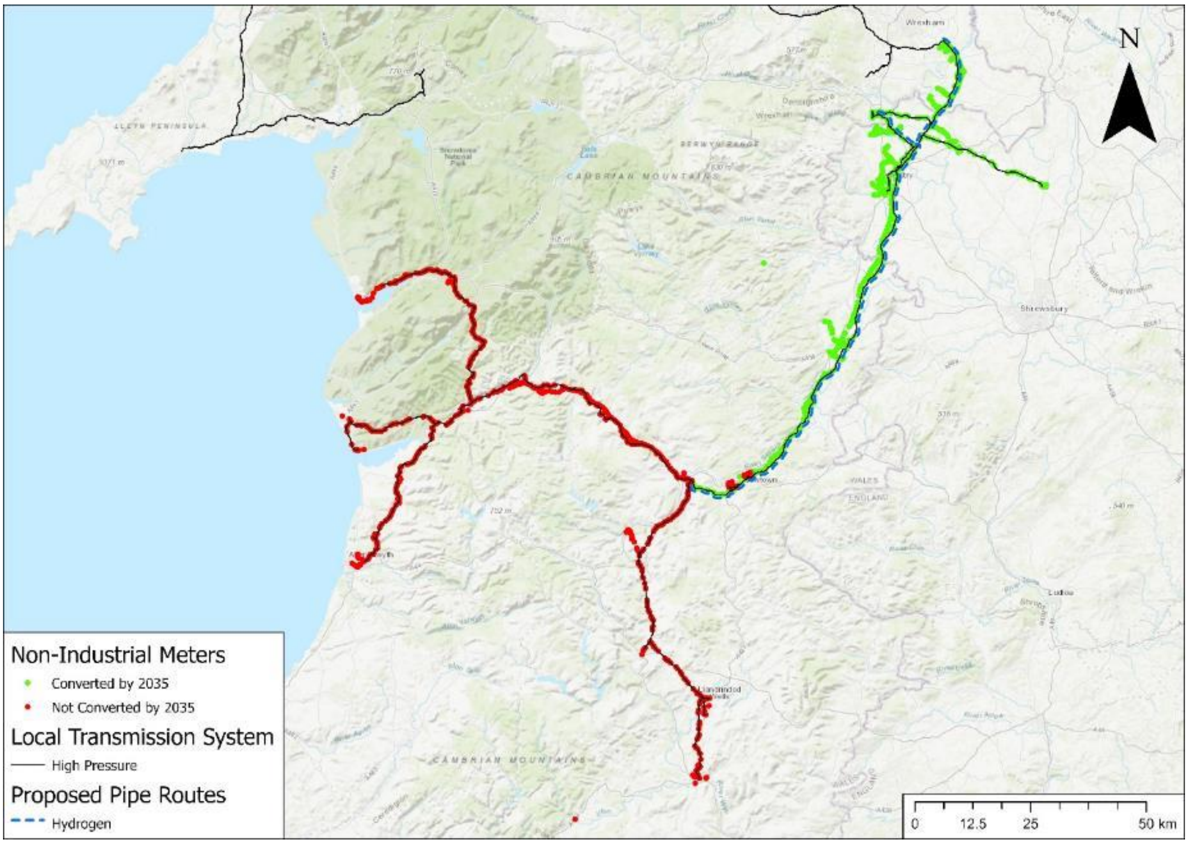


Figure 26.22. 2040 – 2050 High Electrification - Domestic and commercial Meters

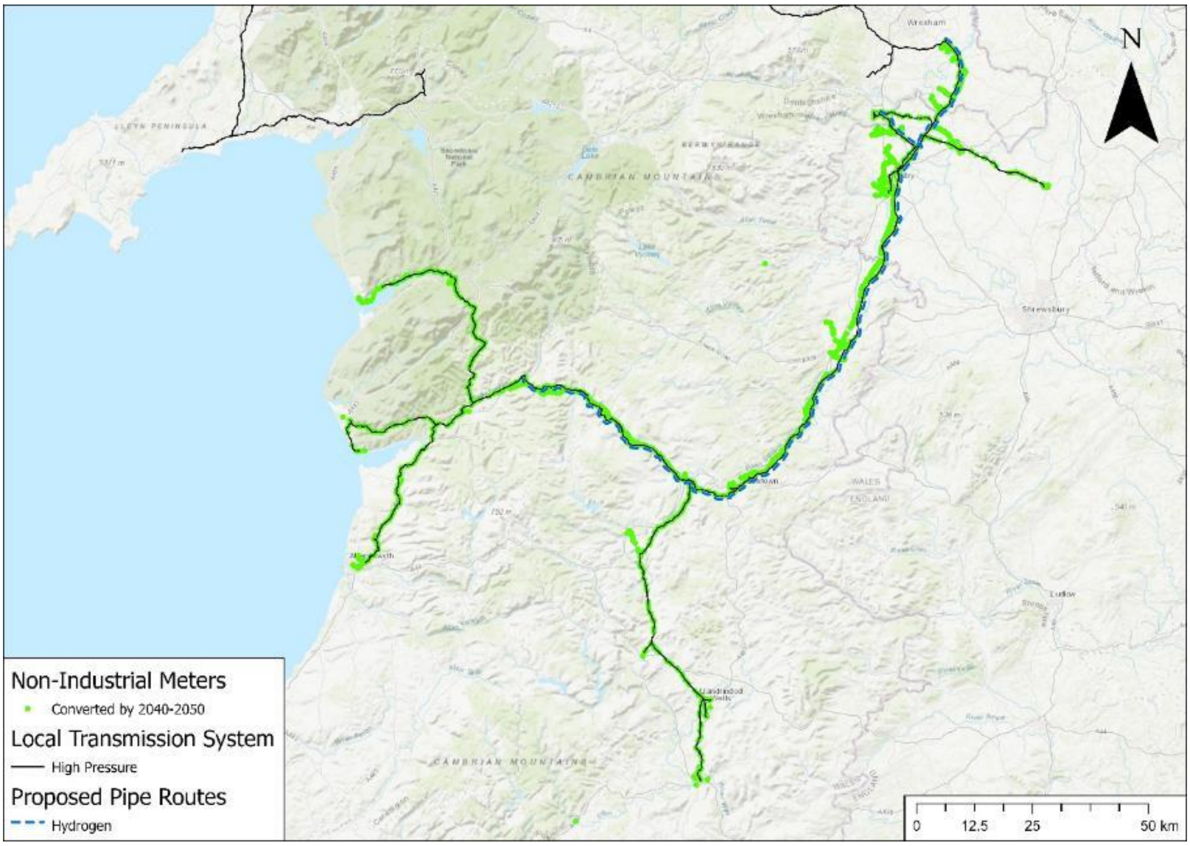
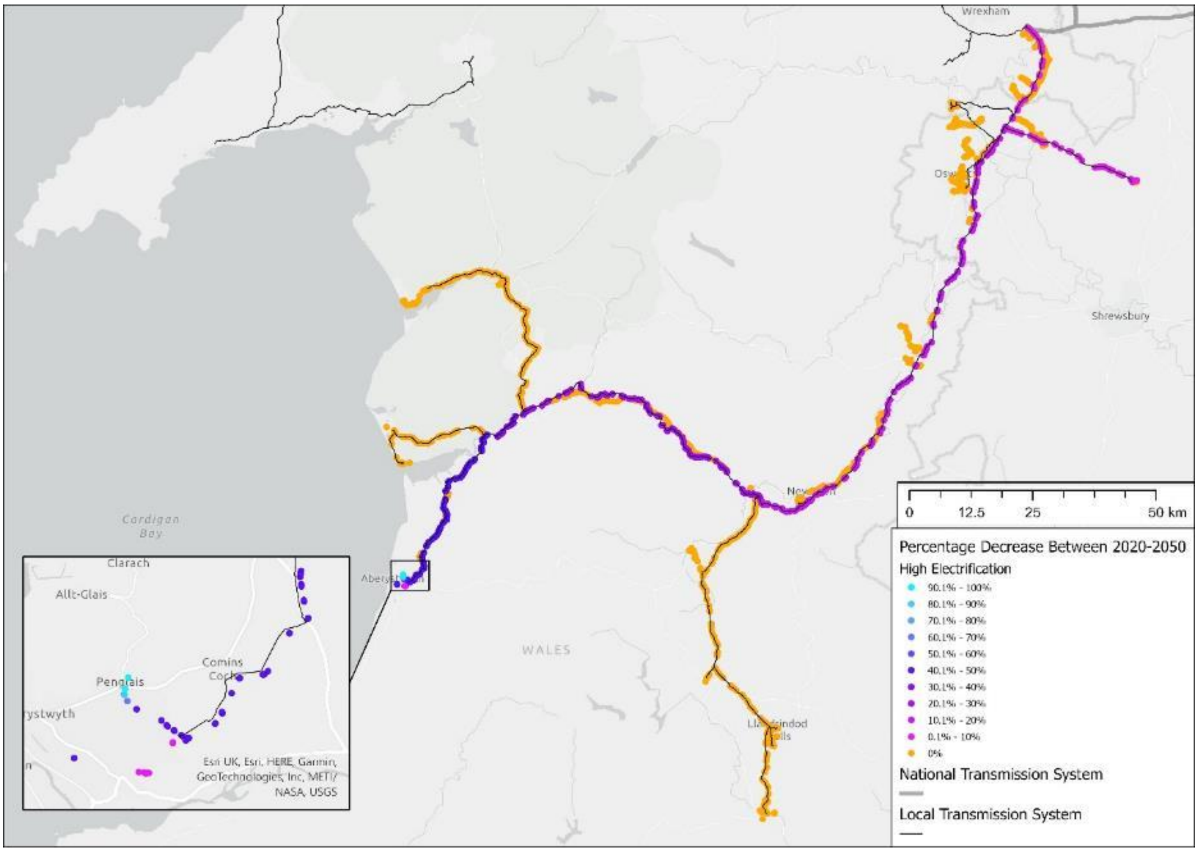


Figure 26.23. % Change in the Domestic and commercial Meters – High Electrification in 2050



26.1.2. BALANCED (BAL)

According to the Balanced (BAL) WWU scenario modelled in ESME Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 26.9. Wales Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

Wales	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.8	1.2	5.9	11.3	47.8	42.2	33.4
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	2.6	5.2	13.5	13.7	11.7
Natural Gas Consumption from Distribution Network (TWh)	11.9	15.1	9.3	9.8	1.9	0.0	0.0

Figure 26.24. Wales Distribution Network Use by Natural Gas and Hydrogen – Balanced

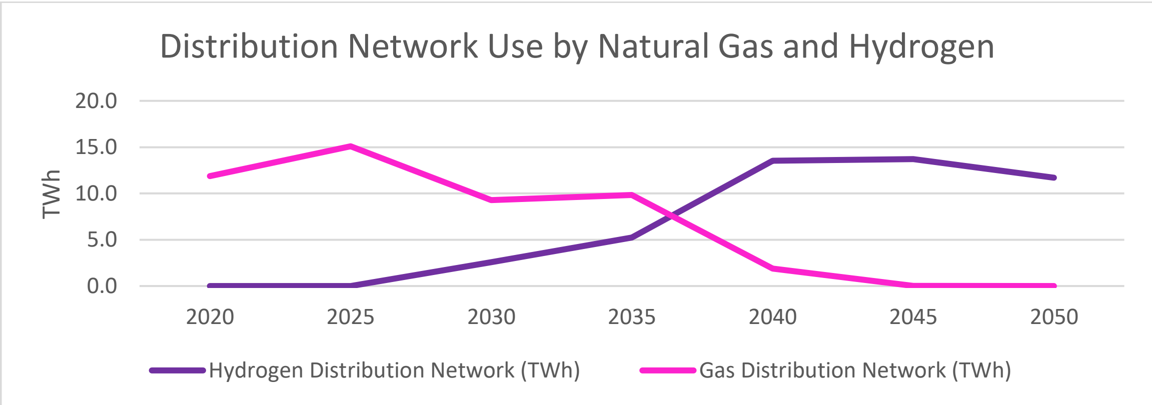


Table 26.10. Mid Wales Meters Converted per 5 Year Cycle – Balanced

Mid Wales	Number of Meters Converted per 5 Year Cycle – Balanced						
	2020	2025	2030	2035	2040	2045	2050
Maelor Mid	0	0	8870	18500	20807	3114	0
Meters Converting per Week (40 Wks/Year)	0	0	44	93	104	16	0

It should be noted that the number of meters requiring conversion each week is based on the assumption that conversion will take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

Figure 26.25. 2020 – 2025 Balanced - Domestic and commercial Meters

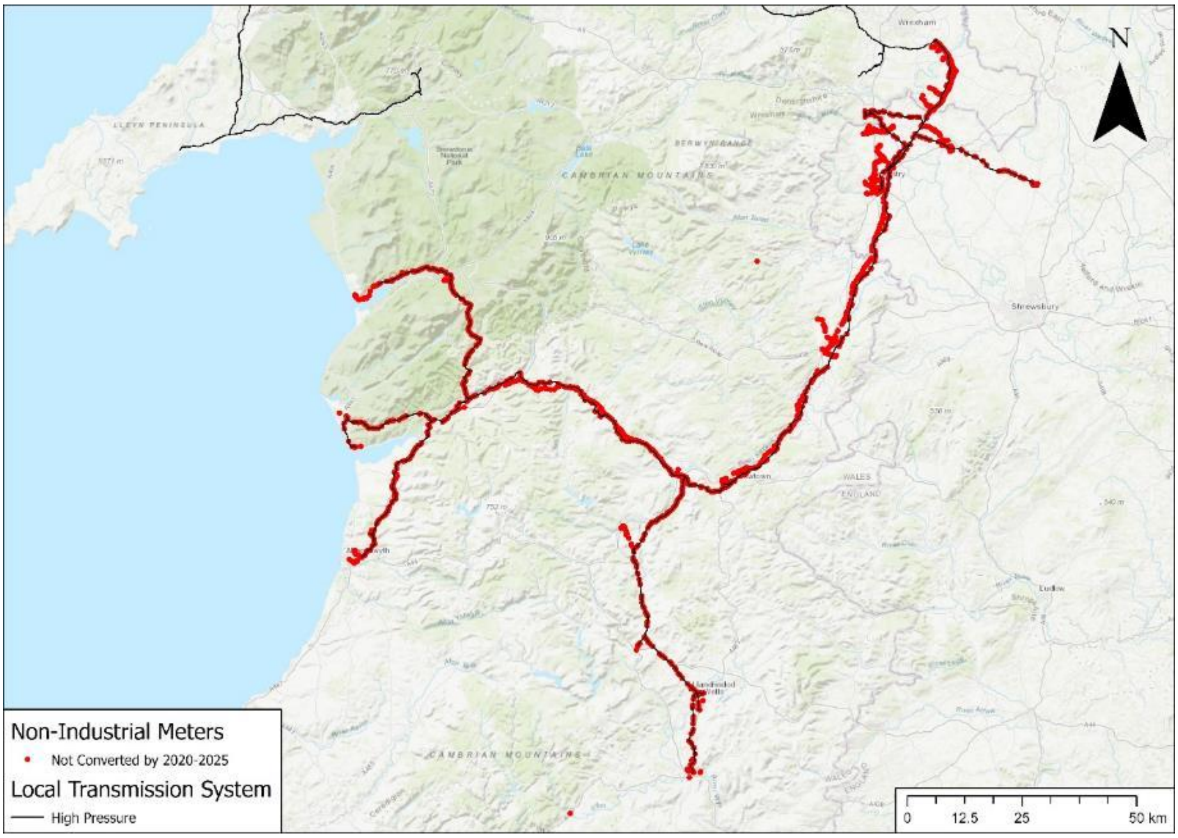


Figure 26.26. 2030 Balanced - Domestic and commercial Meters

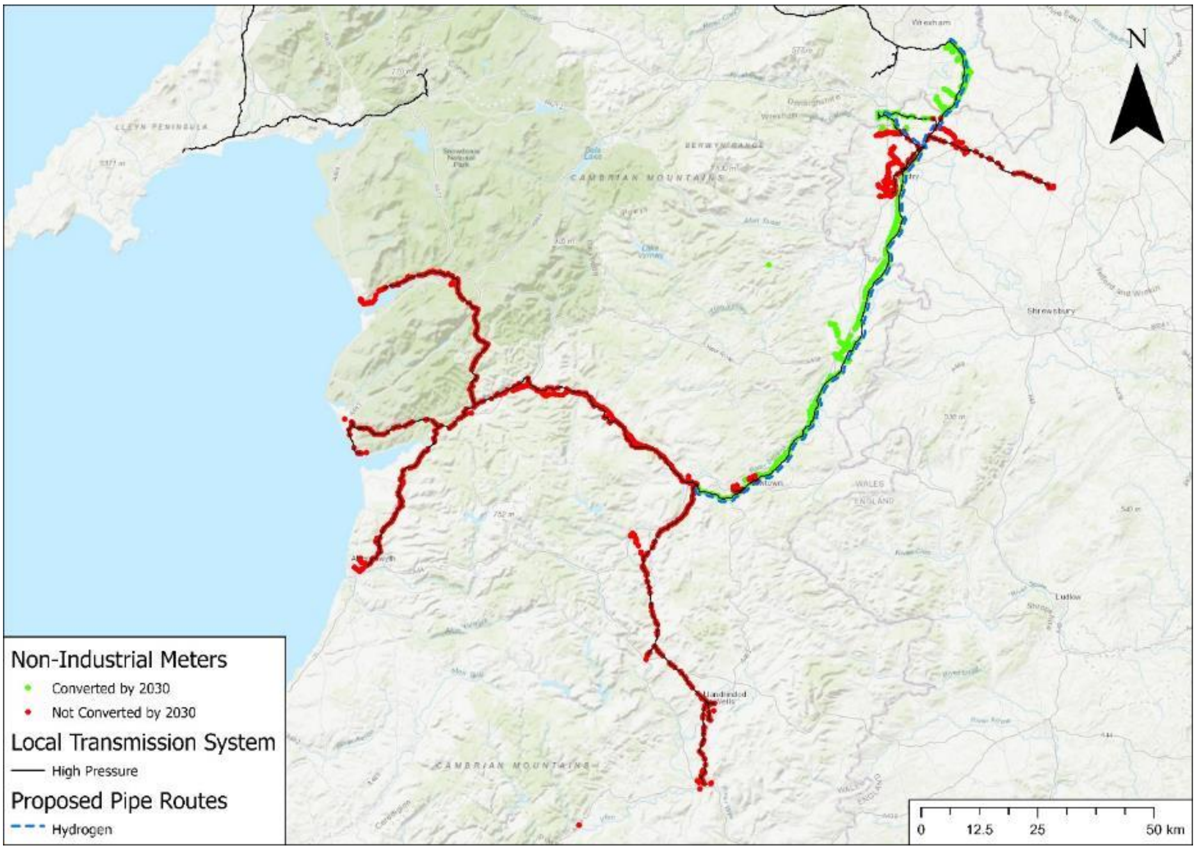


Figure 26.27. 2035 Balanced - Domestic and commercial Meters

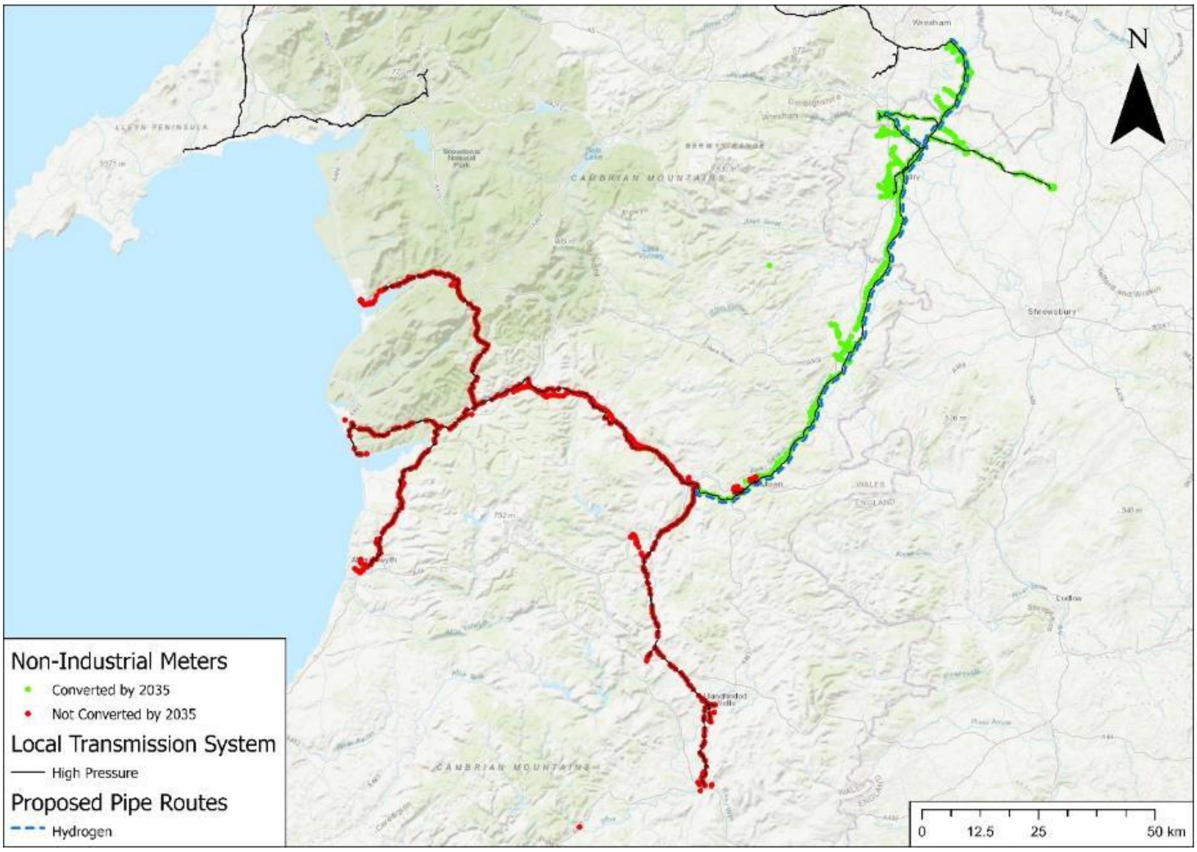


Figure 26.28. 2040 Balanced - Domestic and commercial Meters

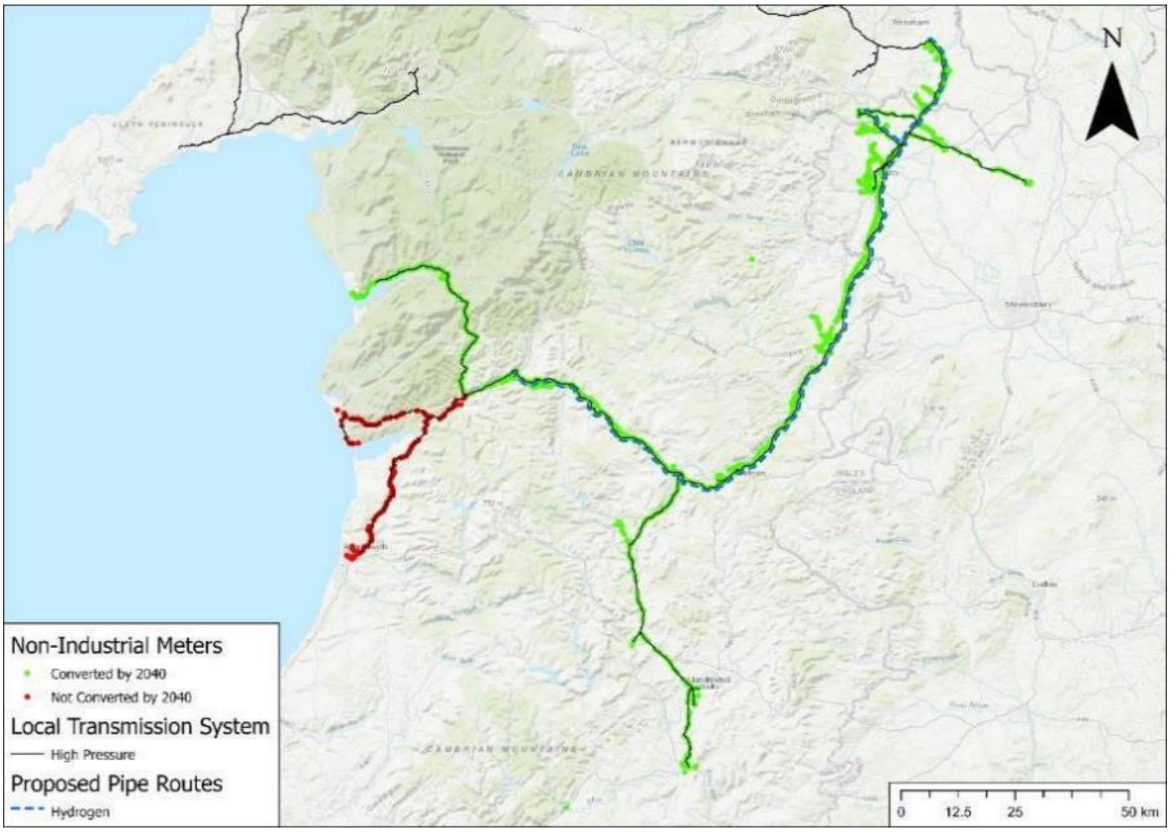


Figure 26.29. 2045 – 2050 Balanced - Domestic and commercial Meters

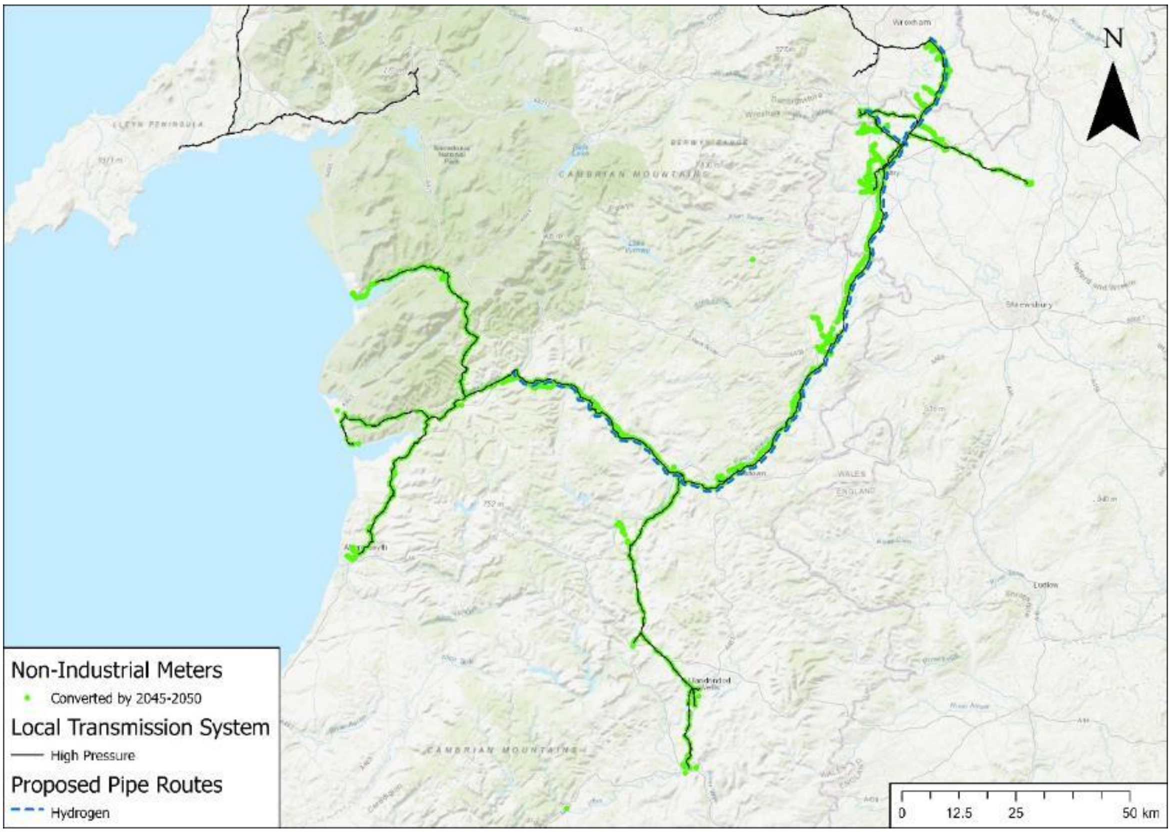
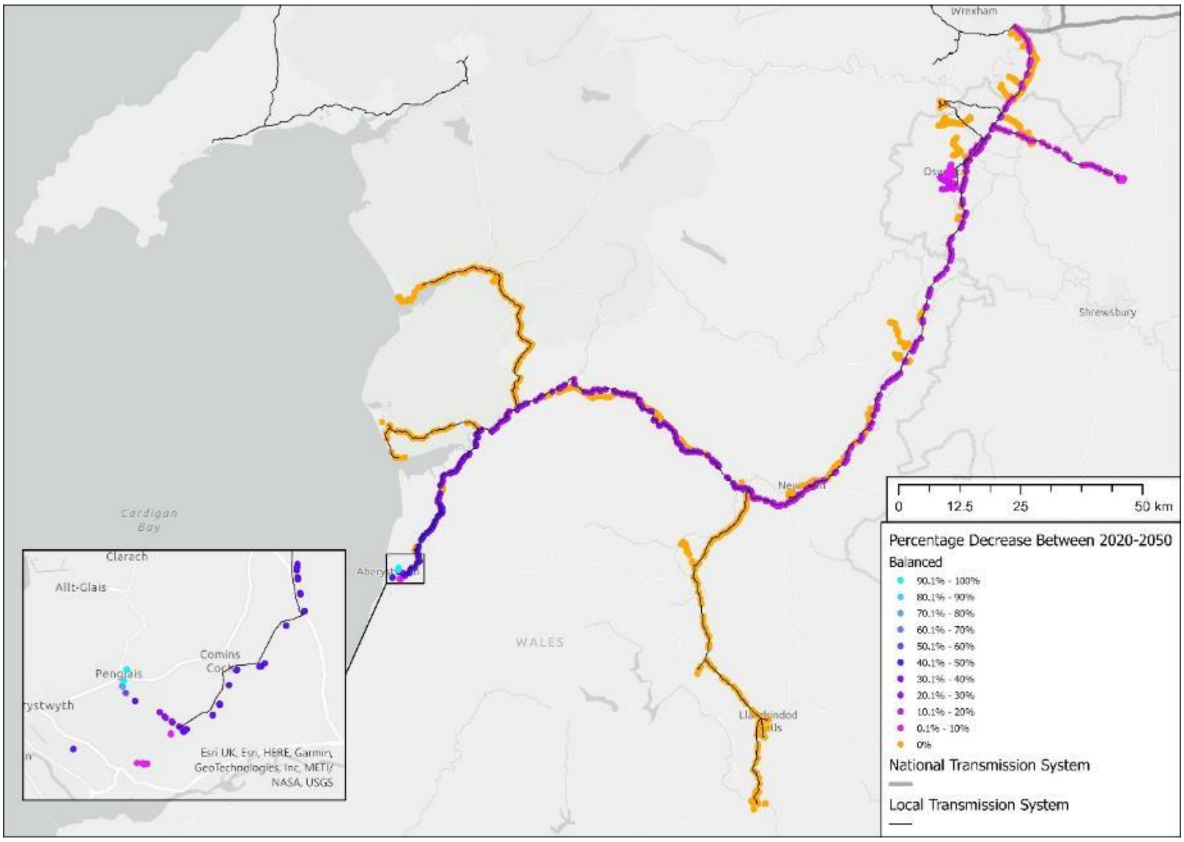


Figure 26.30. % Change in the Domestic and commercial Meters – Balanced in 2050



26.1.3. HIGH HYDROGEN (HYD)

According to the High Hydrogen (HYD) WWU scenarios modelled in ESME Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 26.11. Wales Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

Wales	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.6	1.1	4.6	10.8	54.0	50.0	40.1
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	2.2	5.4	14.2	14.7	12.4
Natural Gas Consumption from Distribution Network (TWh)	11.8	15.2	9.9	10.5	2.1	0.0	0.0

Figure 26.31. Wales Distribution Network Use by Natural Gas and Hydrogen – High Hydrogen

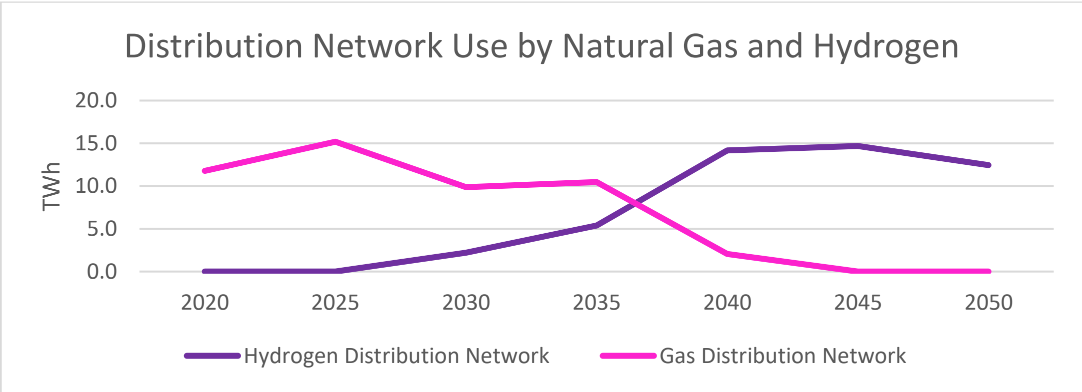


Table 26.12. Mid Wales Meters Converted per 5 Year Cycle – High Hydrogen

Mid Wales	Number of Meters Converted per 5 Year Cycle – High Hydrogen						
	2020	2025	2030	2035	2040	2045	2050
Maelor Mid	0	0	11018	30711	10018	0	0
Meters Converting per Week (40 Wks/Year)	0	0	55	154	50	0	0

It should be noted that the number of meters requiring conversion each week is based on the assumption that conversion will take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

Figure 26.32. 2020 – 2025 High Hydrogen - Domestic and commercial Meters

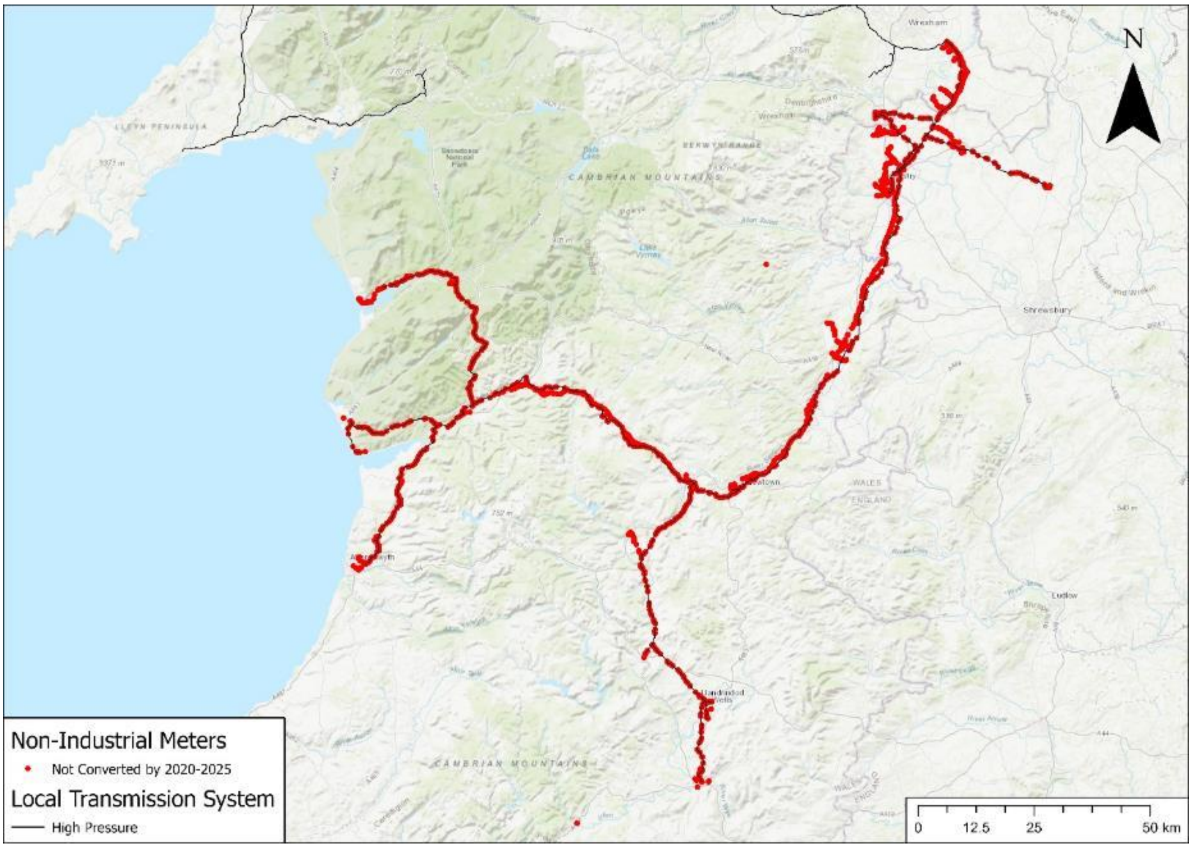


Figure 26.33. 2030 High Hydrogen - Domestic and commercial Meters

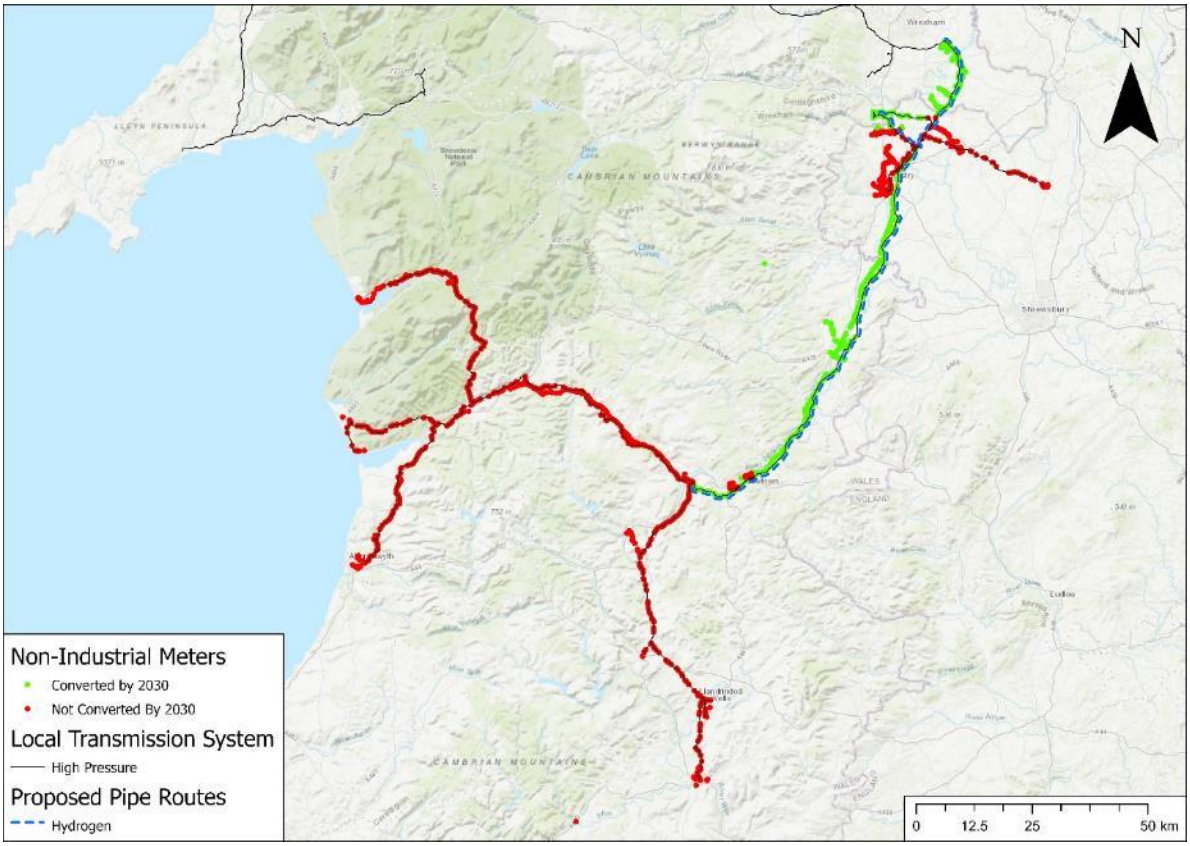


Figure 26.34. 2035 High Hydrogen - Domestic and commercial Meters

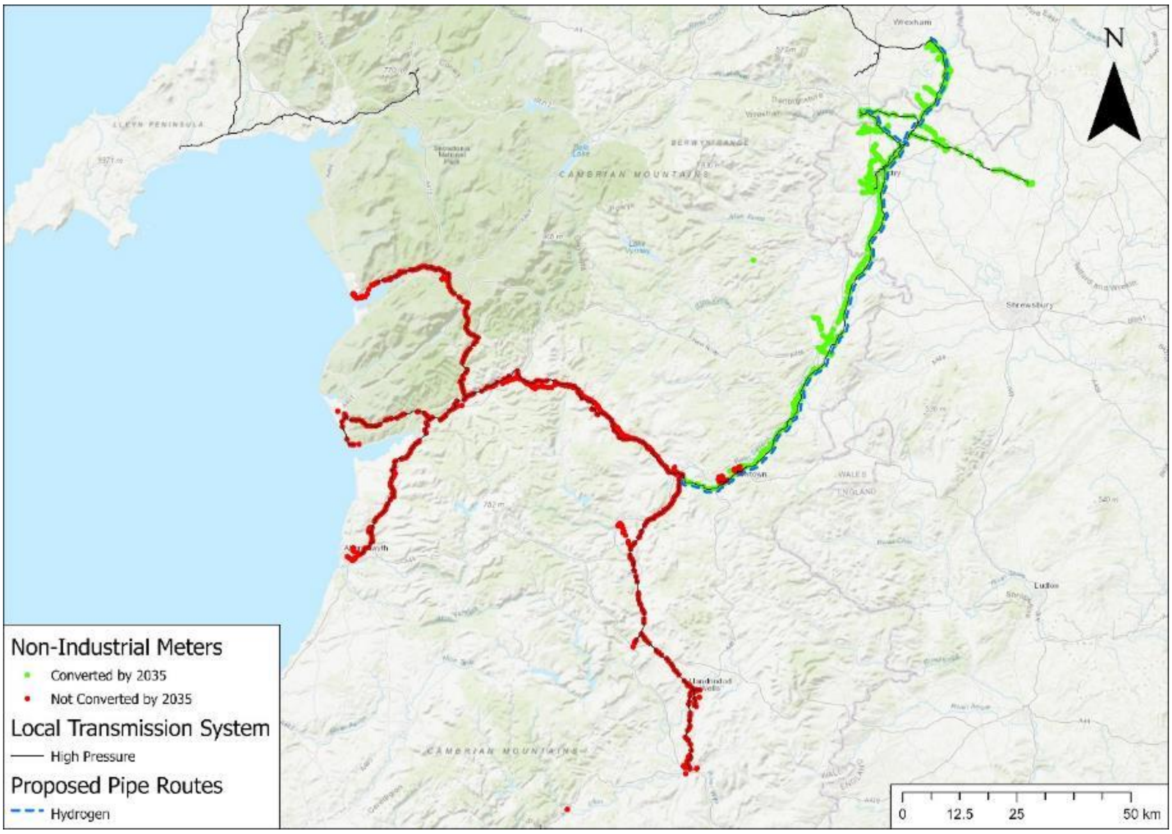


Figure 26.35. 2040 - 50 High Hydrogen - Domestic and commercial Meters

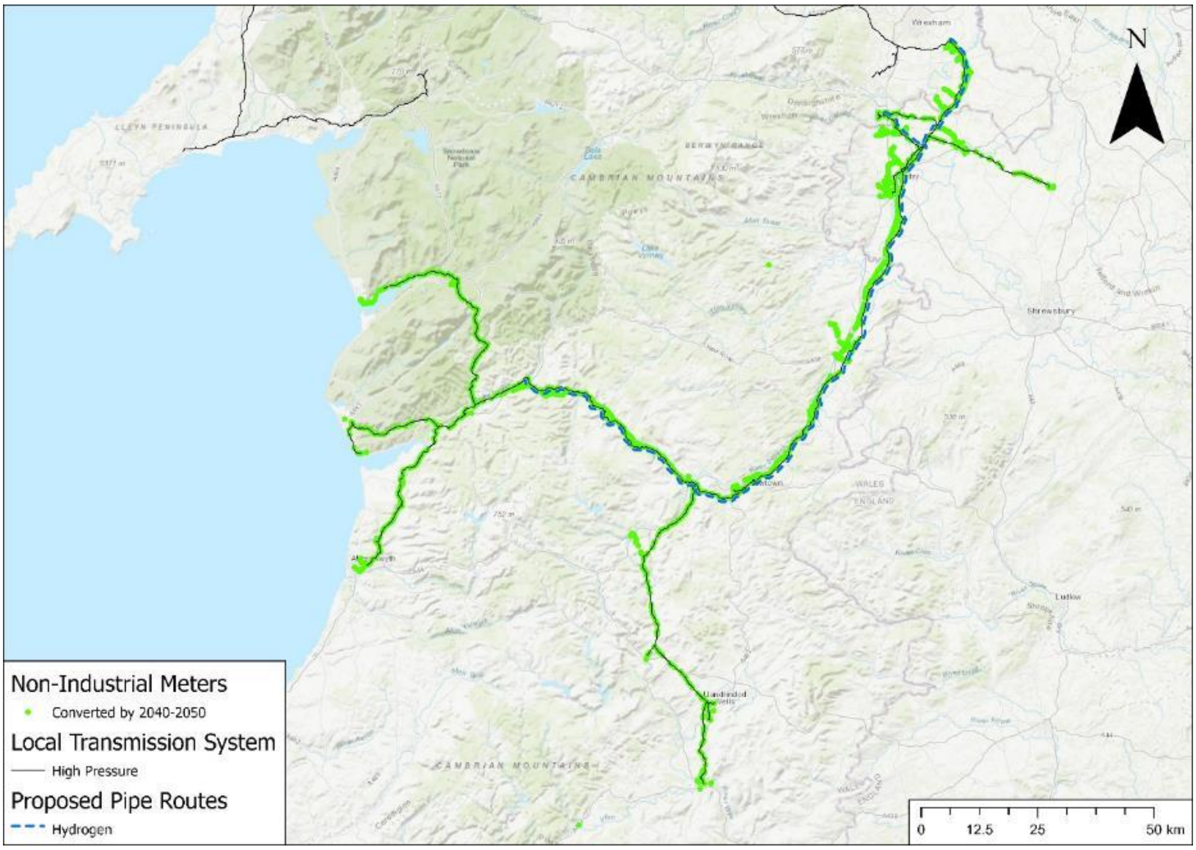
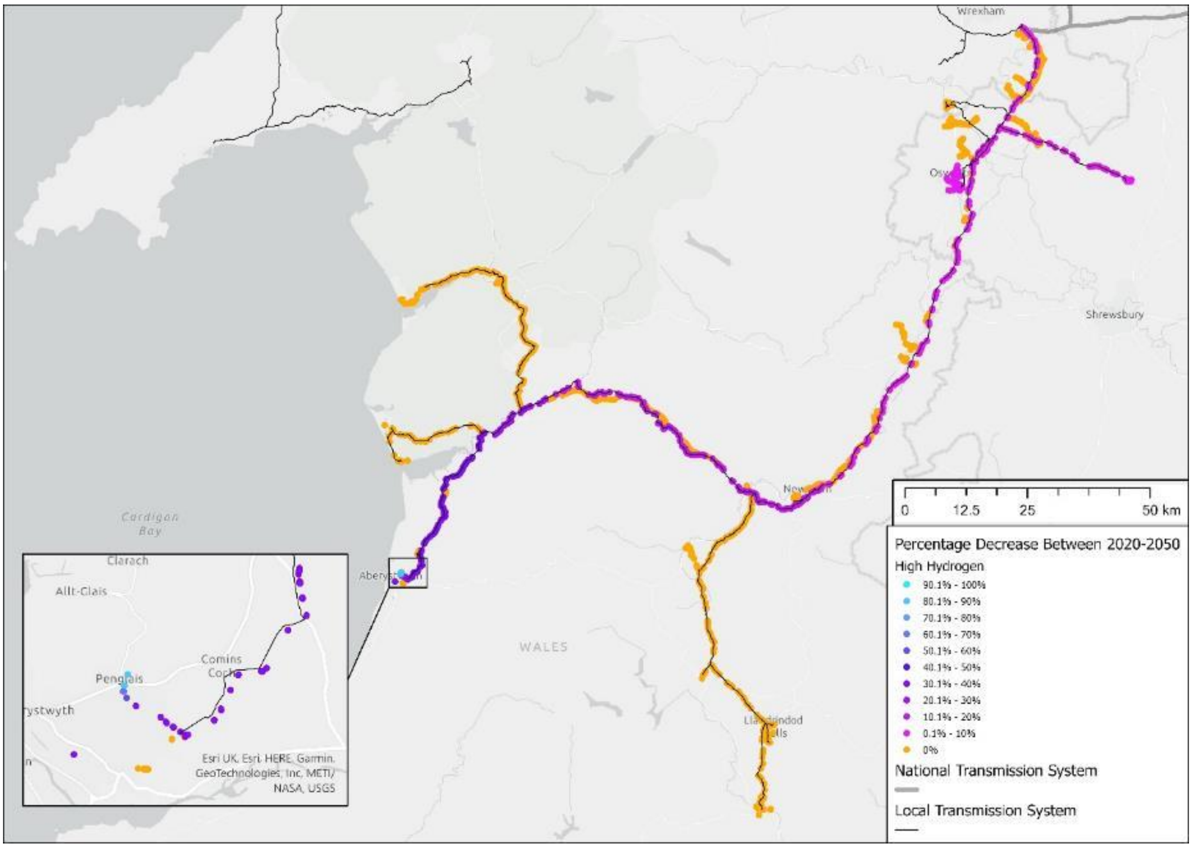


Figure 26.36. % Change in the Domestic and commercial Meters – High Hydrogen in 2050



26.2. SOUTH WALES

26.2.1. HIGH ELECTRIFICATION (ELE)

According to the High Electrification (ELE) WWU scenario modelled in ESME Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 26.13. Wales Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

Wales	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.4	0.7	1.0	10.4	37.4	34.1	26.0
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	0.0	2.1	9.8	5.6	4.4
Natural Gas Consumption from Distribution Network (TWh)	13.0	15.5	12.4	8.2	0.4	0.0	0.0

Figure 26.37. Wales Distribution Network Use by Natural Gas and Hydrogen – High Electrification

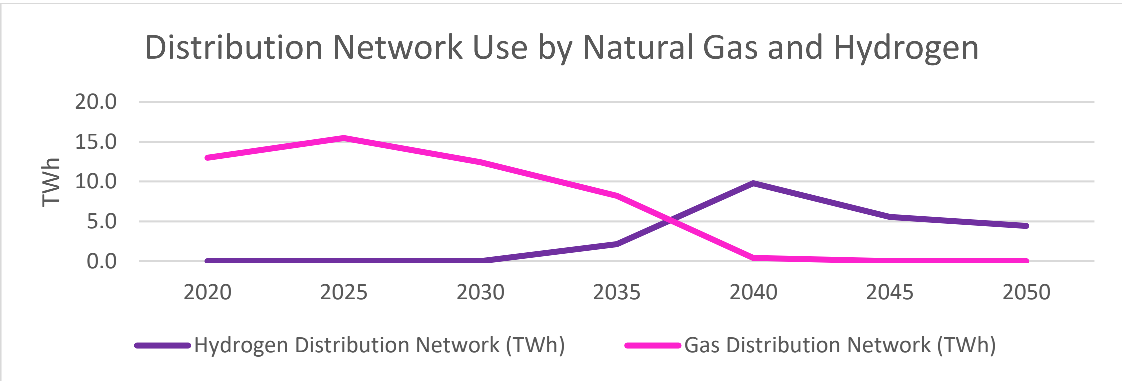


Table 26.14. South Wales Meters Converted per 5 Year Cycle – High Electrification

South Wales	Number of Meters Converted per 5 Year Cycle – High Electrification						
	2020	2025	2030	2035	2040	2045	2050
Dowlais	0	0	0	98680	366881	0	0
Dyffryn	0	0	0	157888	42720	0	0
Gilwern	0	0	0	0	170200	86188	0
Total				256569	579802	86188	0
Meters Converting per Week (40 Wks/Year)	0	0	0	1283	2899	431	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

In 2040 the number of meters requiring conversion is higher than the recommended figure of 2500 from the HYDROGEN1 Project, therefore either an additional conversion team will be required, or a number of meters scheduled for 2040 would have to be push back into 2045.

Figure 26.38. 2020 – 2030 High Electrification - Domestic and commercial Meters

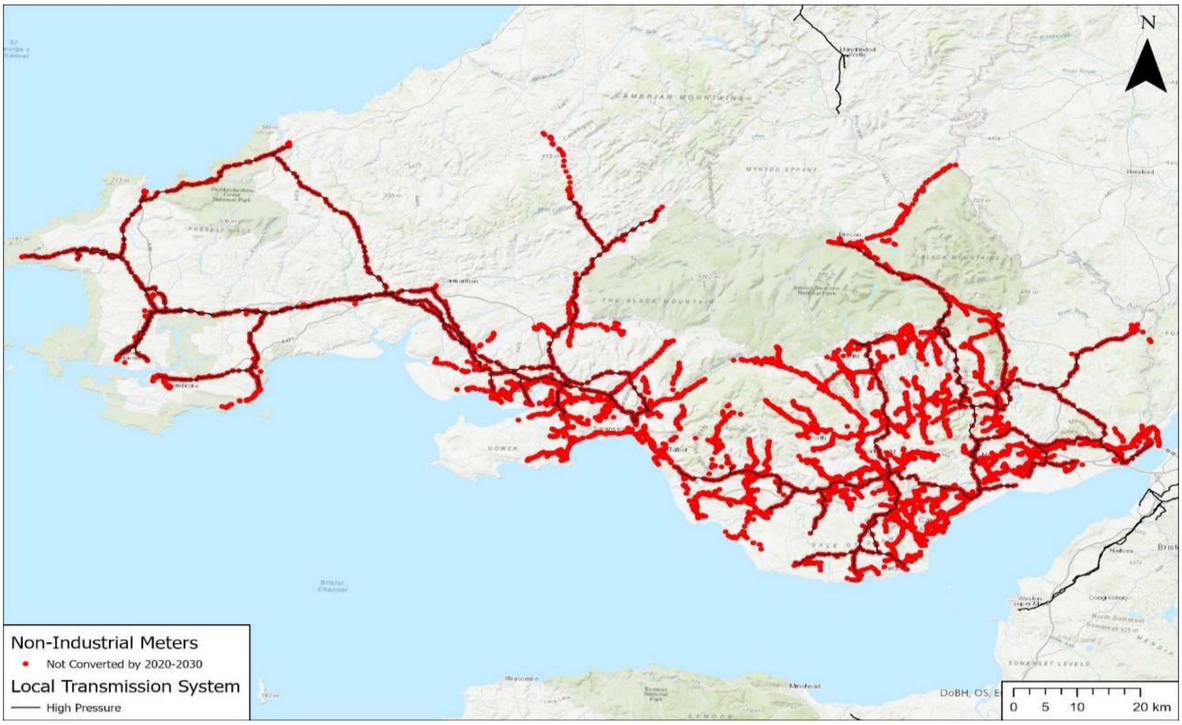


Figure 26.39. 2035 High Electrification - Domestic and commercial Meters

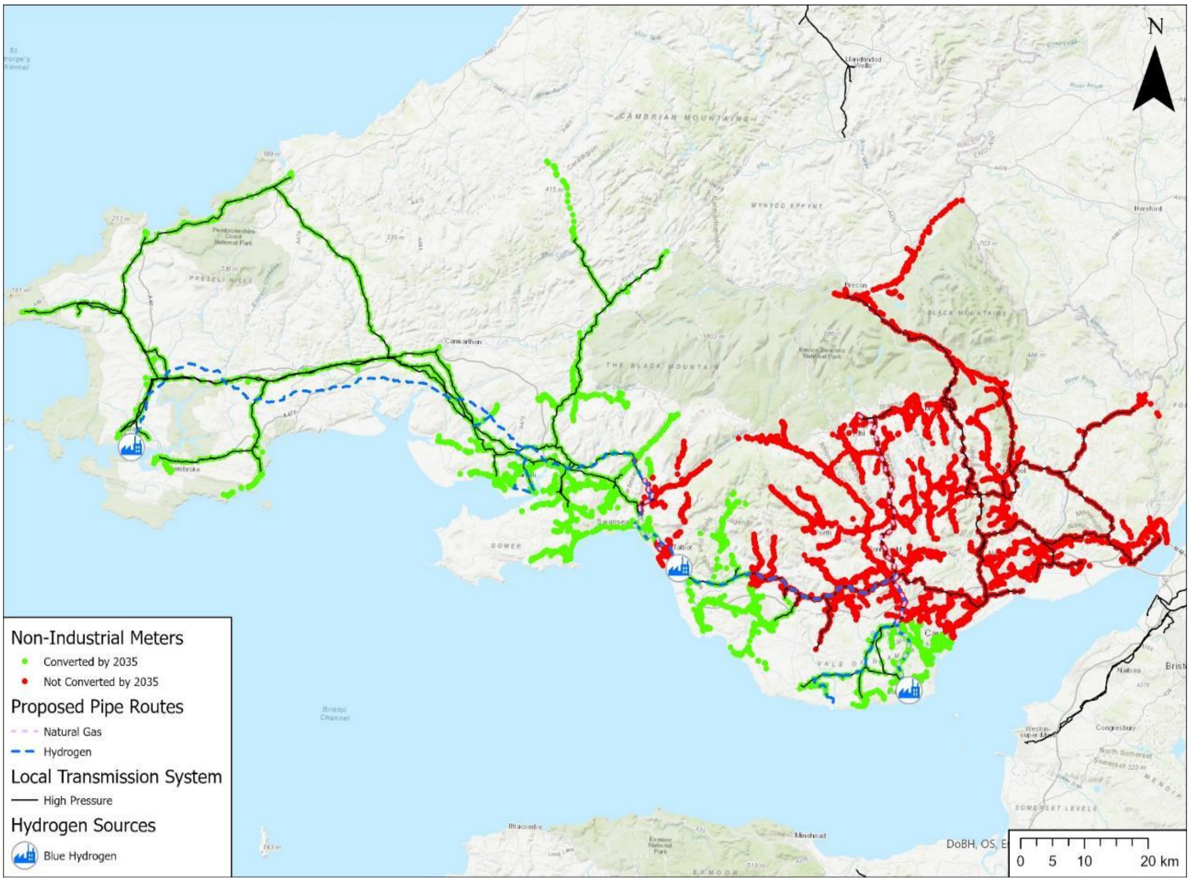


Figure 26.40. 2040 – 2050 High Electrification - Domestic and commercial Meters

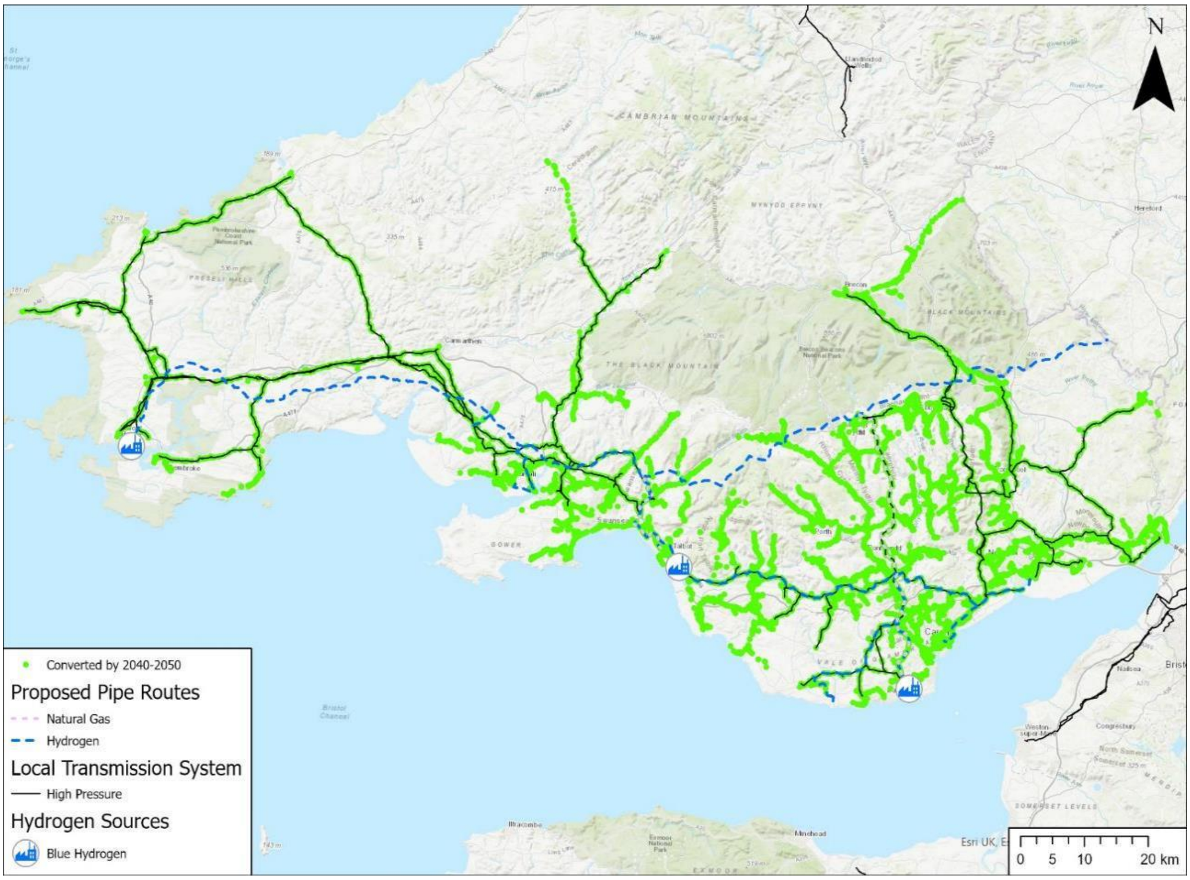
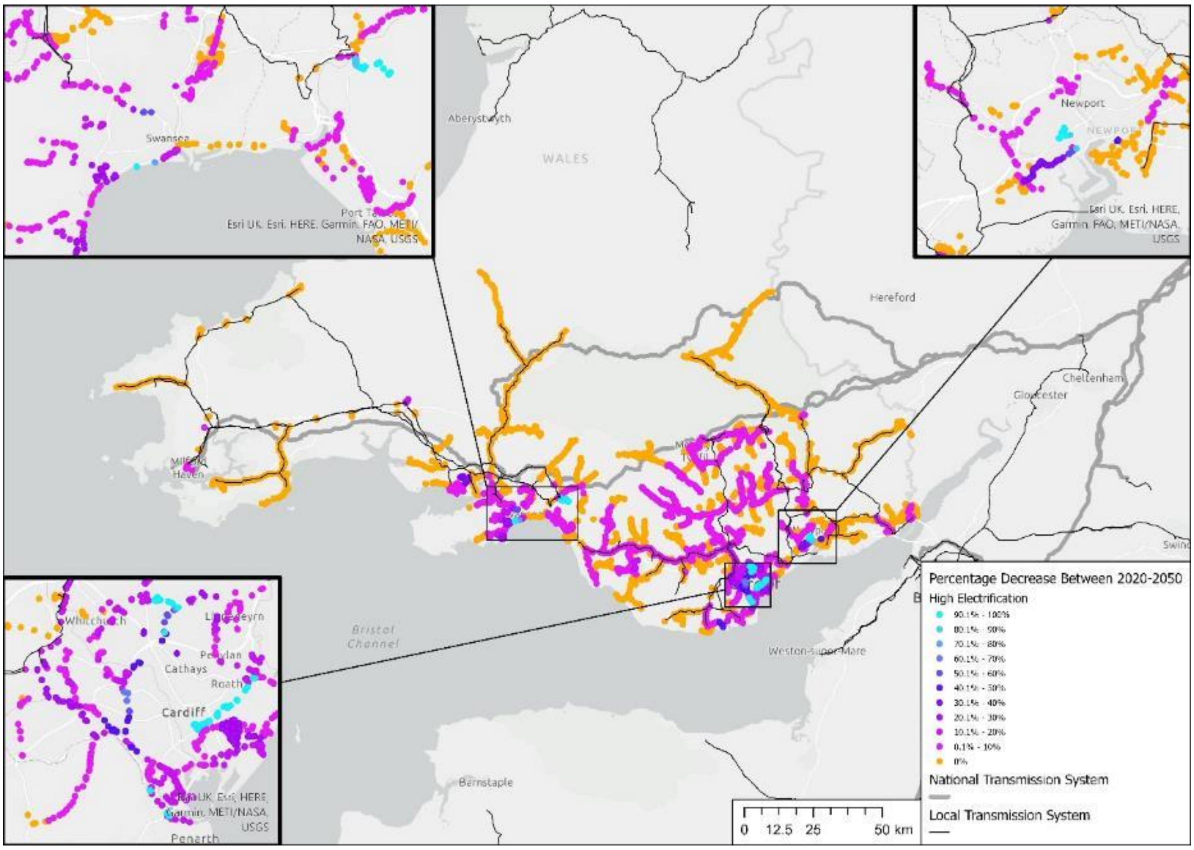


Figure 26.41. % Change in the Domestic and commercial Meters – High Electrification in 2050



26.2.2. BALANCED (BAL)

For Balanced (BAL) according to the WWU scenario modelled in ESME Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 26.15. Wales Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

Wales	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.8	1.2	5.9	11.3	47.8	42.2	33.4
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	2.6	5.2	13.5	13.7	11.7
Natural Gas Consumption from Distribution Network (TWh)	11.9	15.1	9.3	9.8	1.9	0.0	0.0

Figure 26.42. Wales Distribution Network Use by Natural Gas and Hydrogen – Balanced

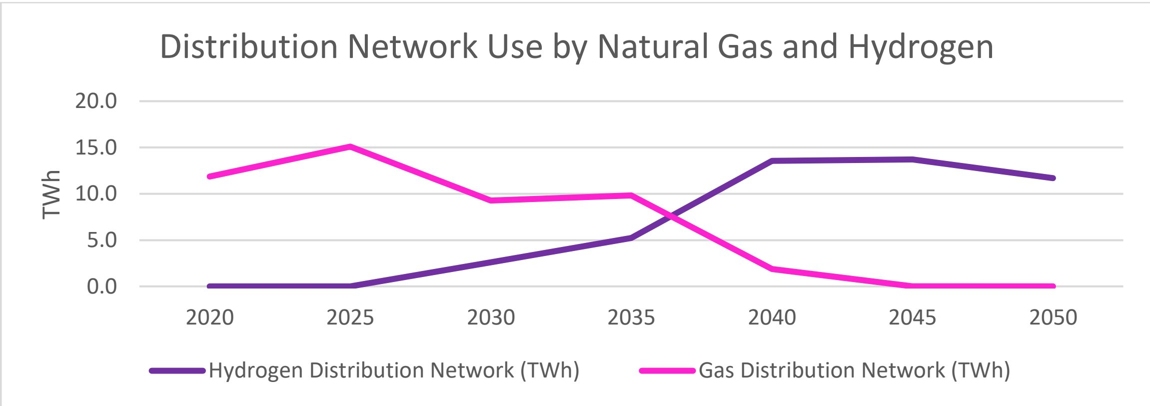


Table 26.16. South Wales Meters Converted per 5 Year Cycle – Balanced

South Wales	Number of Meters Converted per 5 Year Cycle – Balanced						
	2020	2025	2030	2035	2040	2045	2050
Dowlais	0	0	0	78158	387523	0	0
Dyffryn	0	0	144209	24035	32416	0	0
Gilwern	0	0	0	0	153545	21964	0
Total	0	0	144209	102193	573485	21964	0
Meters Converting per Week (40 Wks/Year)	0	0	721	511	2867	110	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

In 2040 the number of meters requiring conversion is higher than the recommended figure of 2500 from the HYDROGEN1 Project, therefore either an additional conversion team will be required, or a number of meters scheduled for 2040 would have to be push back into 2045.

Figure 26.43. 2020 – 2025 Balanced - Domestic and commercial Meters

Figure 26.44. 2030 Balanced - Domestic and commercial Meters

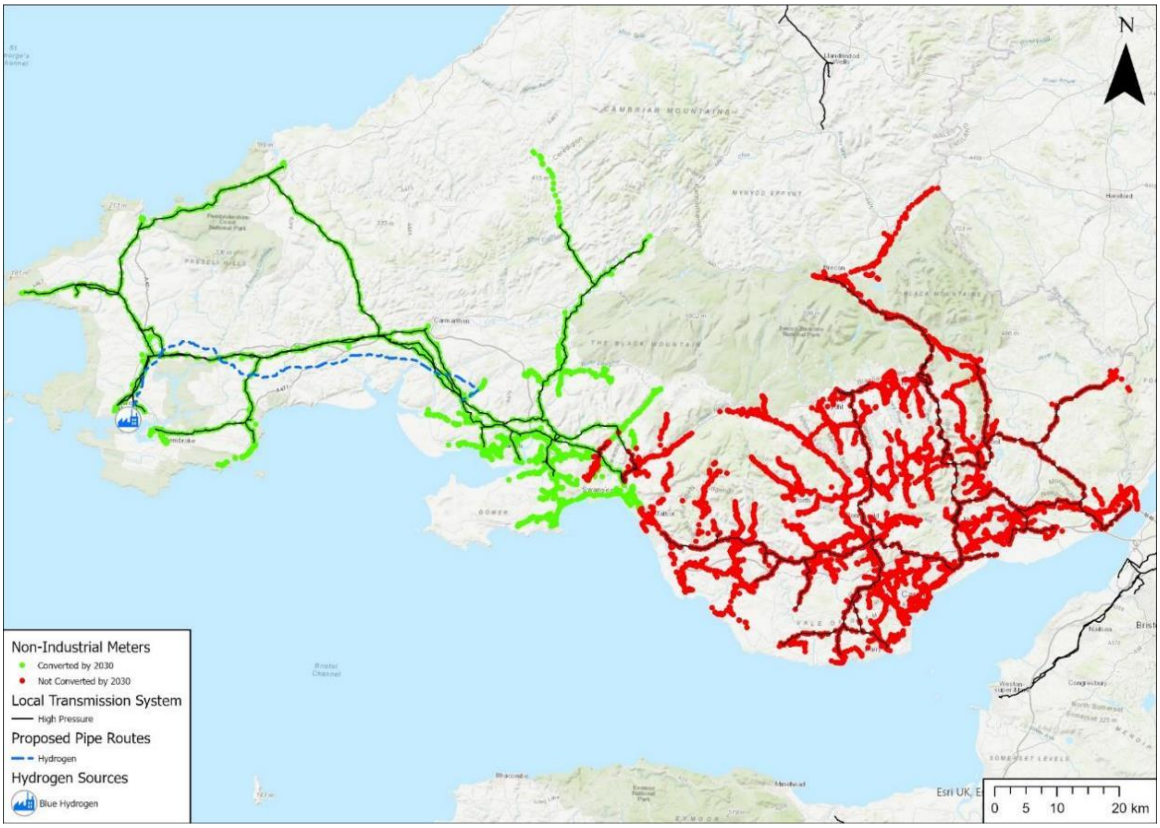


Figure 26.45. 2035 Balanced - Domestic and commercial Meters

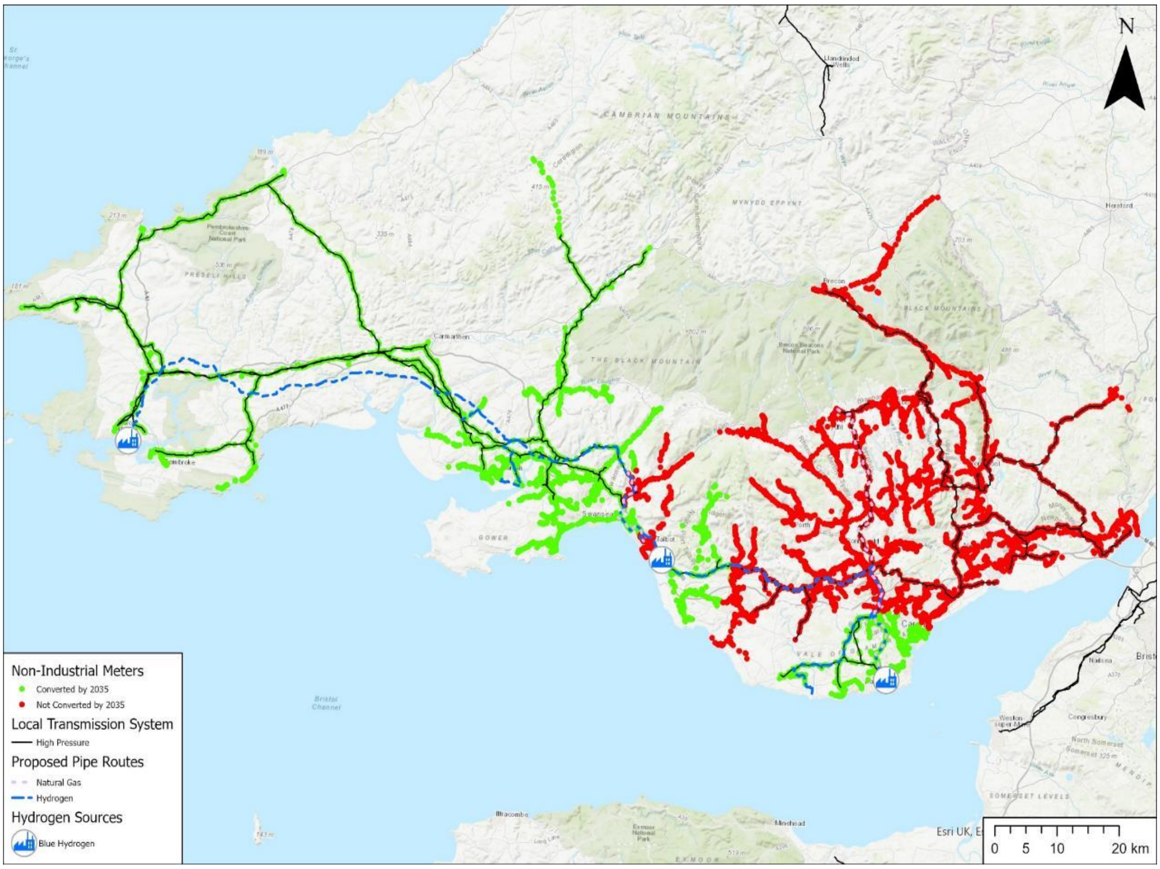


Figure 26.46. 2040 Balanced - Domestic and commercial Meters

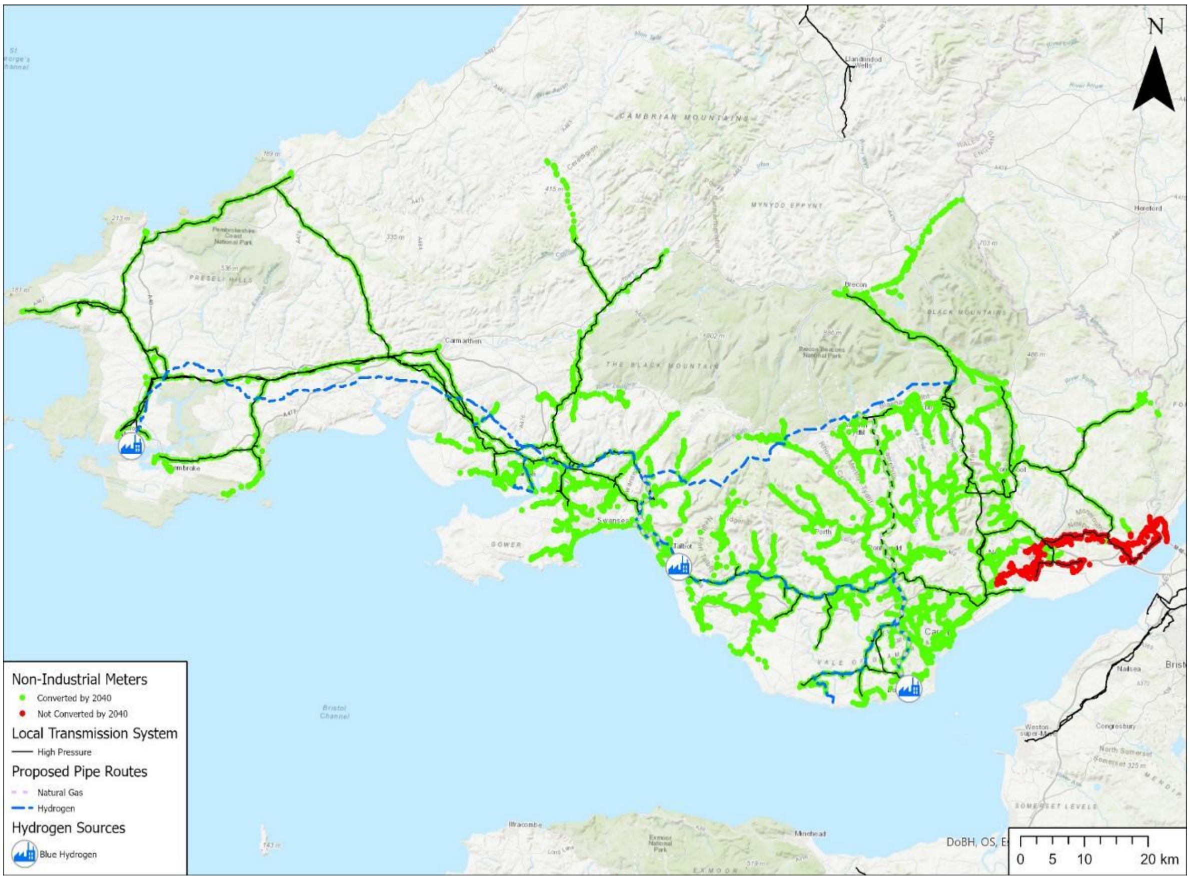


Figure 26.47. 2045 – 2050 Balanced - Domestic and commercial Meters

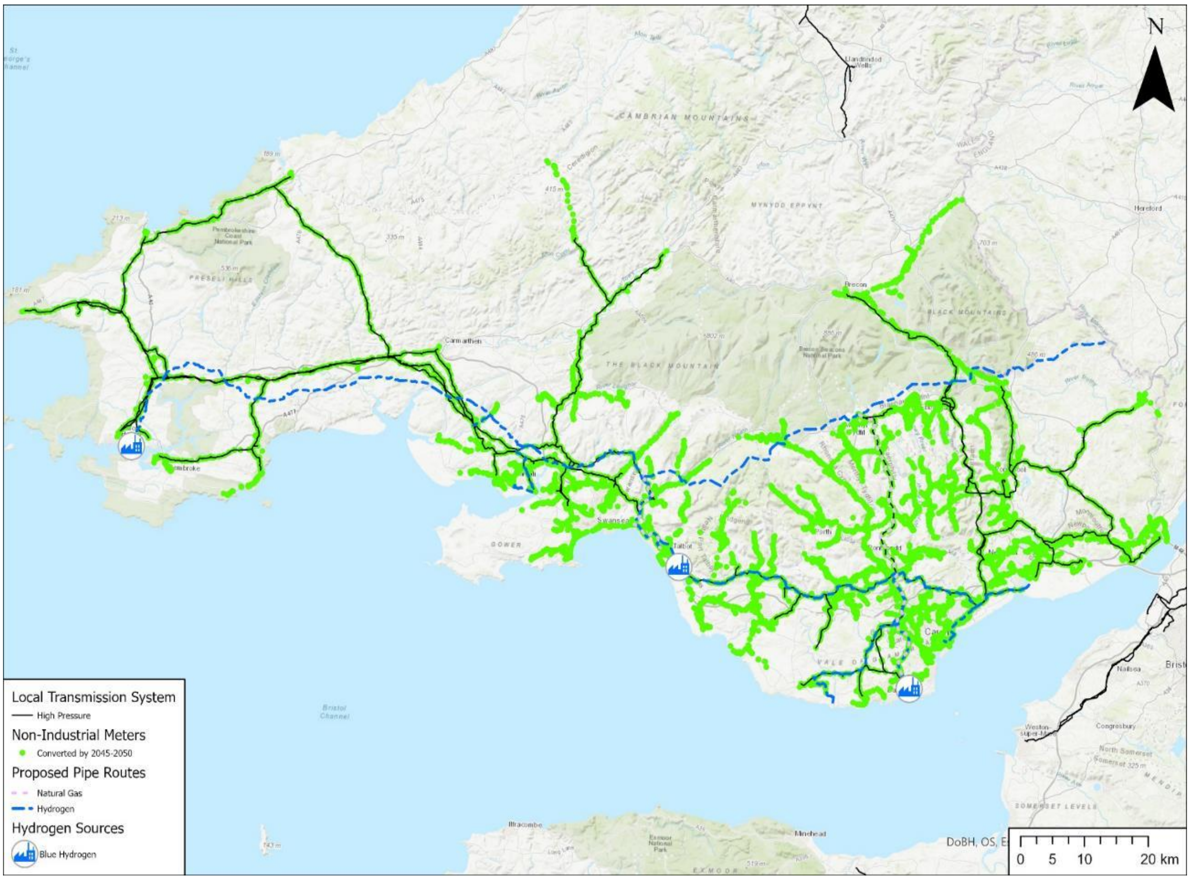
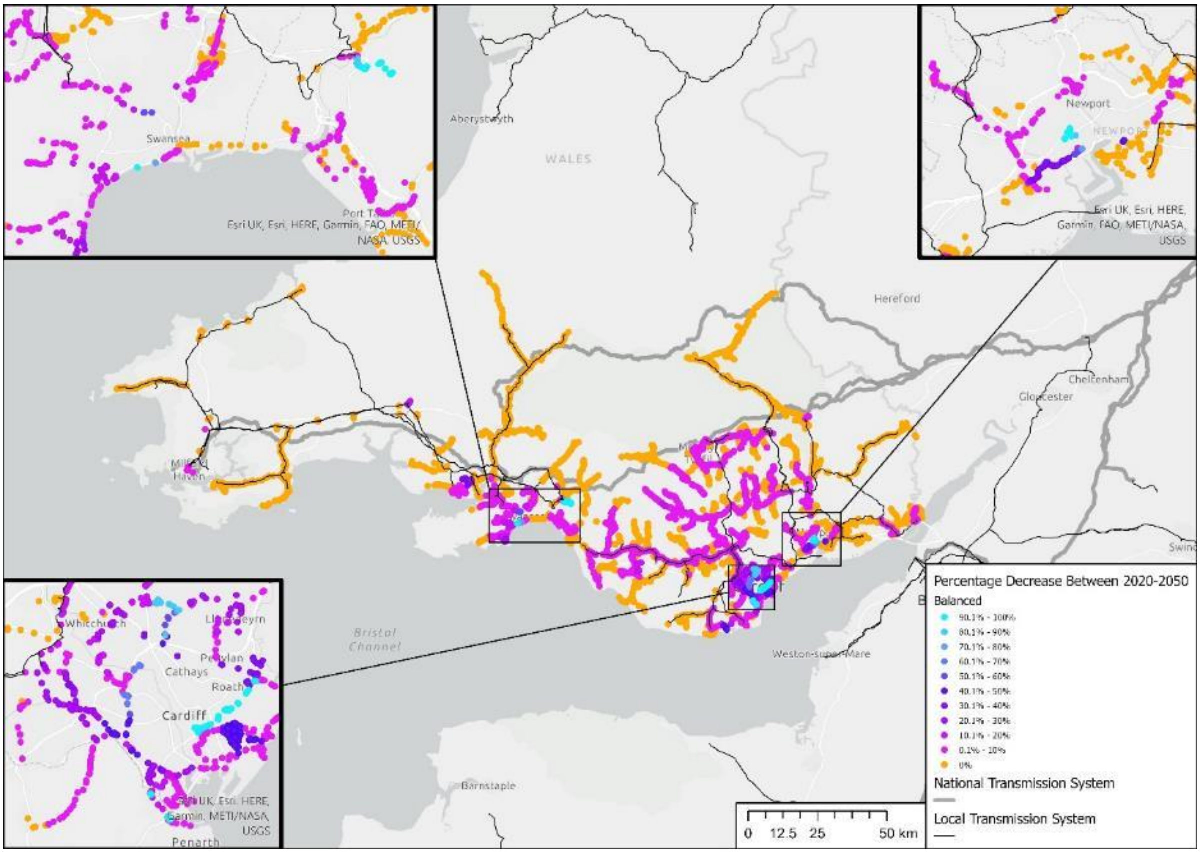


Figure 26.48. % Change in the Domestic and commercial Meters – Balanced in 2050



26.2.3. HIGH HYDROGEN (HYD)

For High Hydrogen (HYD), Hydrogen production in the WWU scenario modelled in ESME starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 26.17. Wales Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

Wales	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.6	1.1	4.6	10.8	54.0	50.0	40.1
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	2.2	5.4	14.2	14.7	12.4
Natural Gas Consumption from Distribution Network (TWh)	11.8	15.2	9.9	10.5	2.1	0.0	0.0

Figure 26.49. Wales Distribution Network Use by Natural Gas and Hydrogen – High Hydrogen

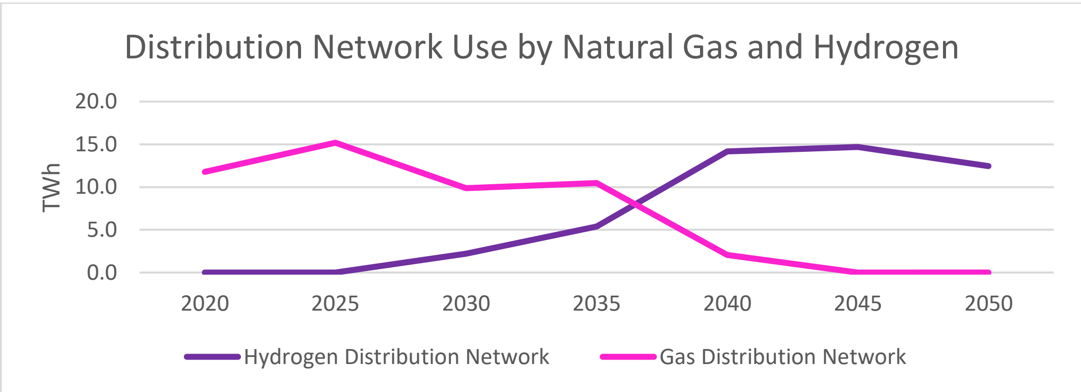


Table 26.18. South Wales Meters Converted per 5 Year Cycle – High Hydrogen

South Wales	Number of Meters Converted per 5 Year Cycle – High Hydrogen						
	2020	2025	2030	2035	2040	2045	2050
Dowlais	0	0	0	75190	394635	0	0
Dyffryn	0	0	135807	22635	44004	0	0
Gilwern	0	0	0	0	141888	35183	0
Total	0	0	135807	97825	580526	35183	0
Meters Converting per Week (40 Wks/Year)	0	0	679	489	2903	176	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

In 2040 the number of meters requiring conversion is higher than the recommended figure of 2500 from the HYDROGEN1 Project, therefore either an additional conversion team will be required, or a number of meters scheduled for 2040 would have to be push back into 2045.

Figure 26.50. 2020 – 2025 High Hydrogen - Domestic and commercial Meters

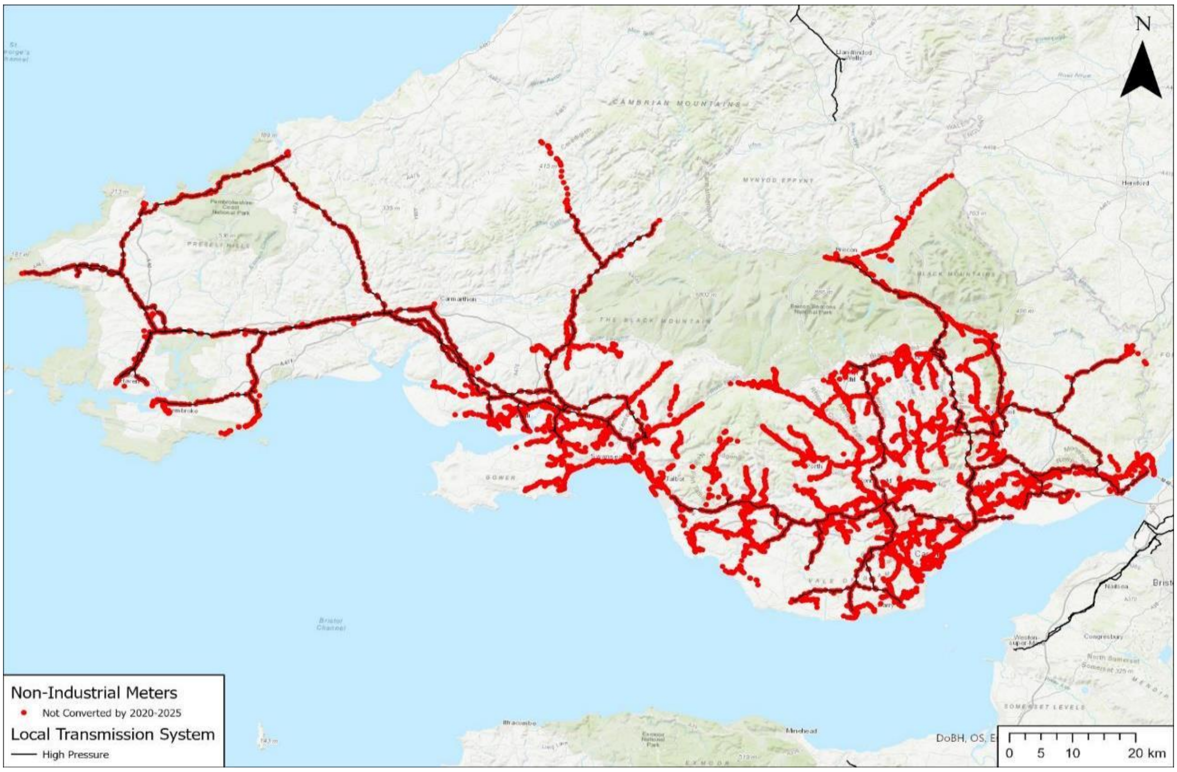


Figure 26.51. 2030 High Hydrogen - Domestic and commercial Meters

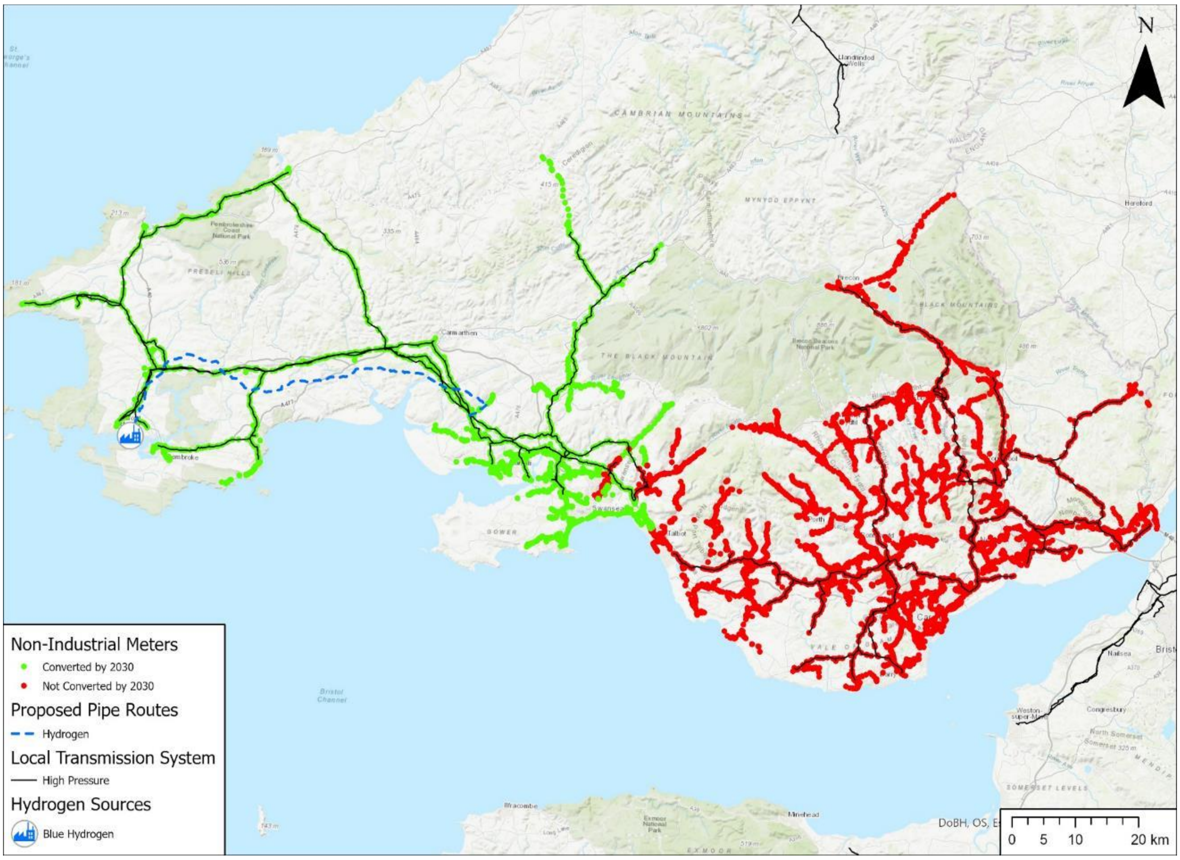


Figure 26.52. 2035 High Hydrogen - Domestic and commercial Meters

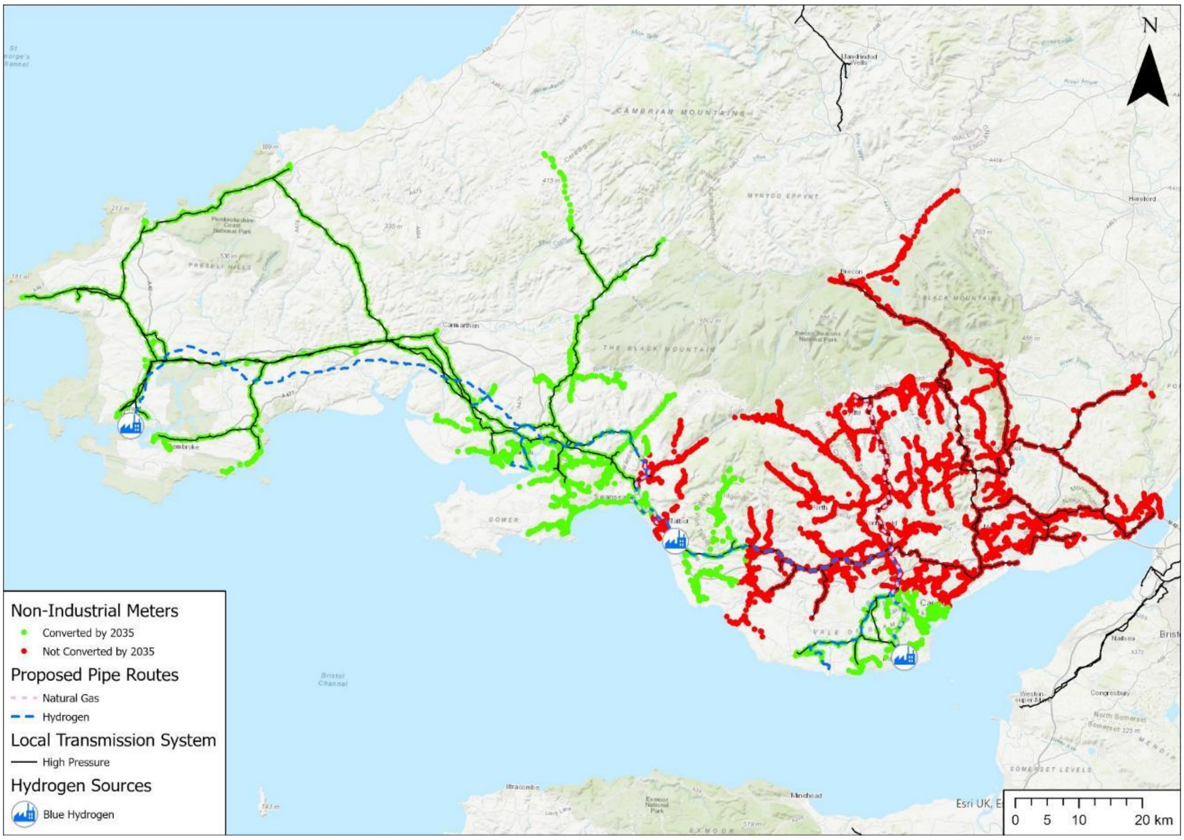


Figure 26.53. 2040 High Hydrogen - Domestic and commercial Meters

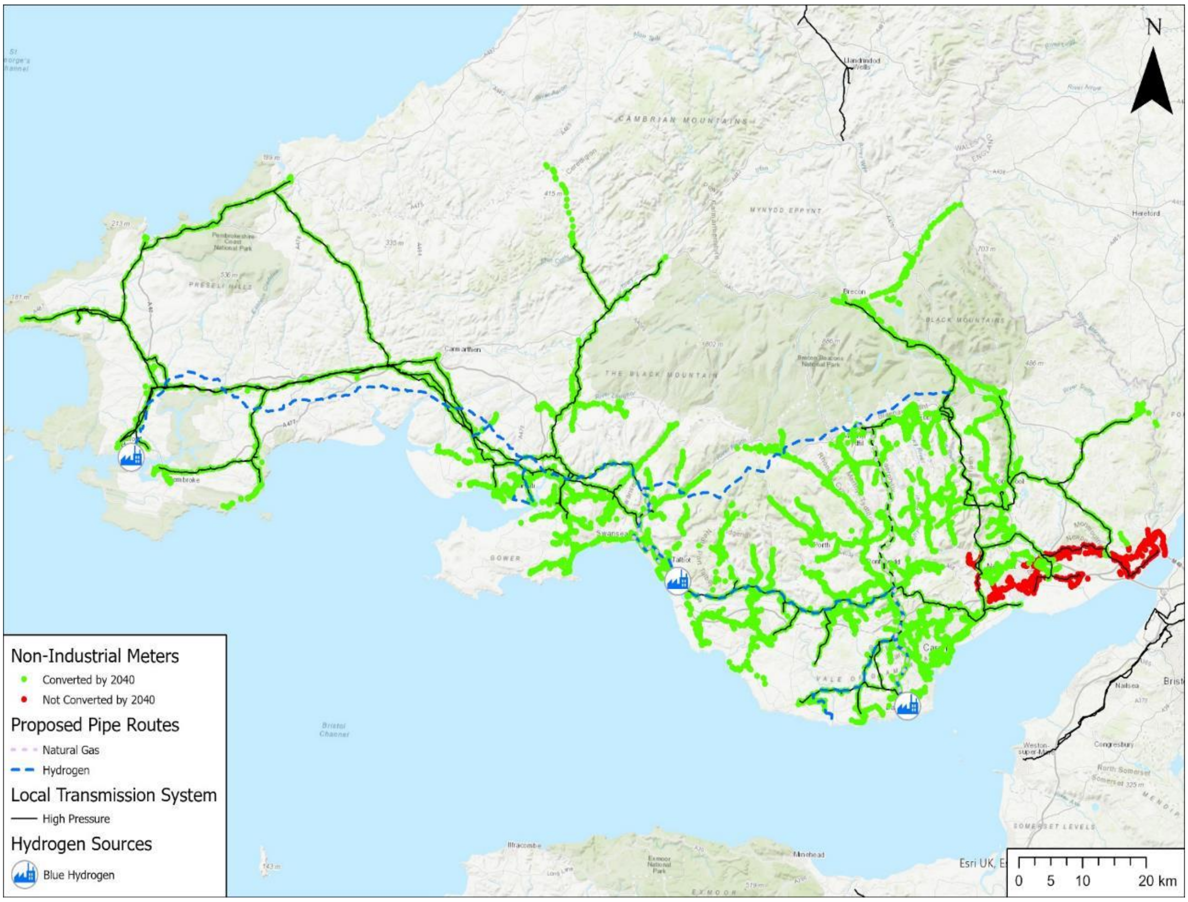


Figure 26.54. 2045 – 2050 High Hydrogen - Domestic and commercial Meters

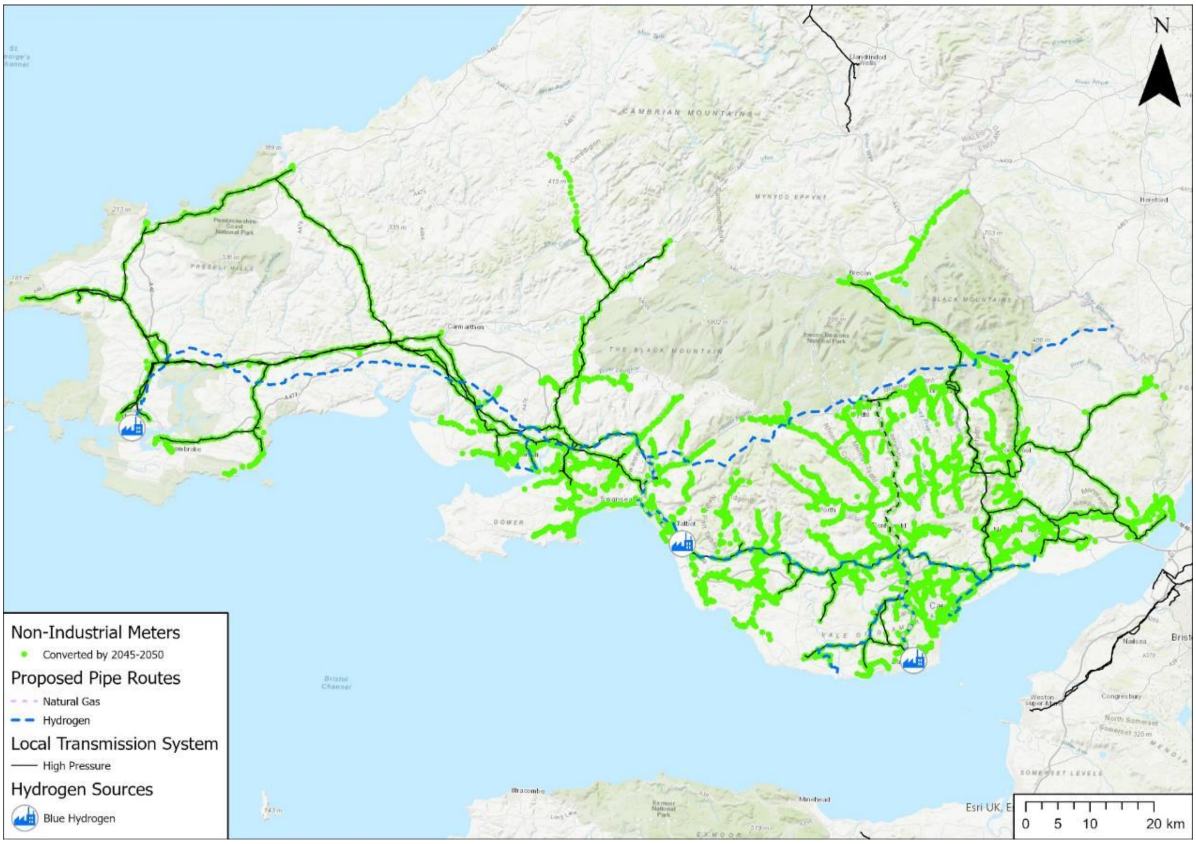
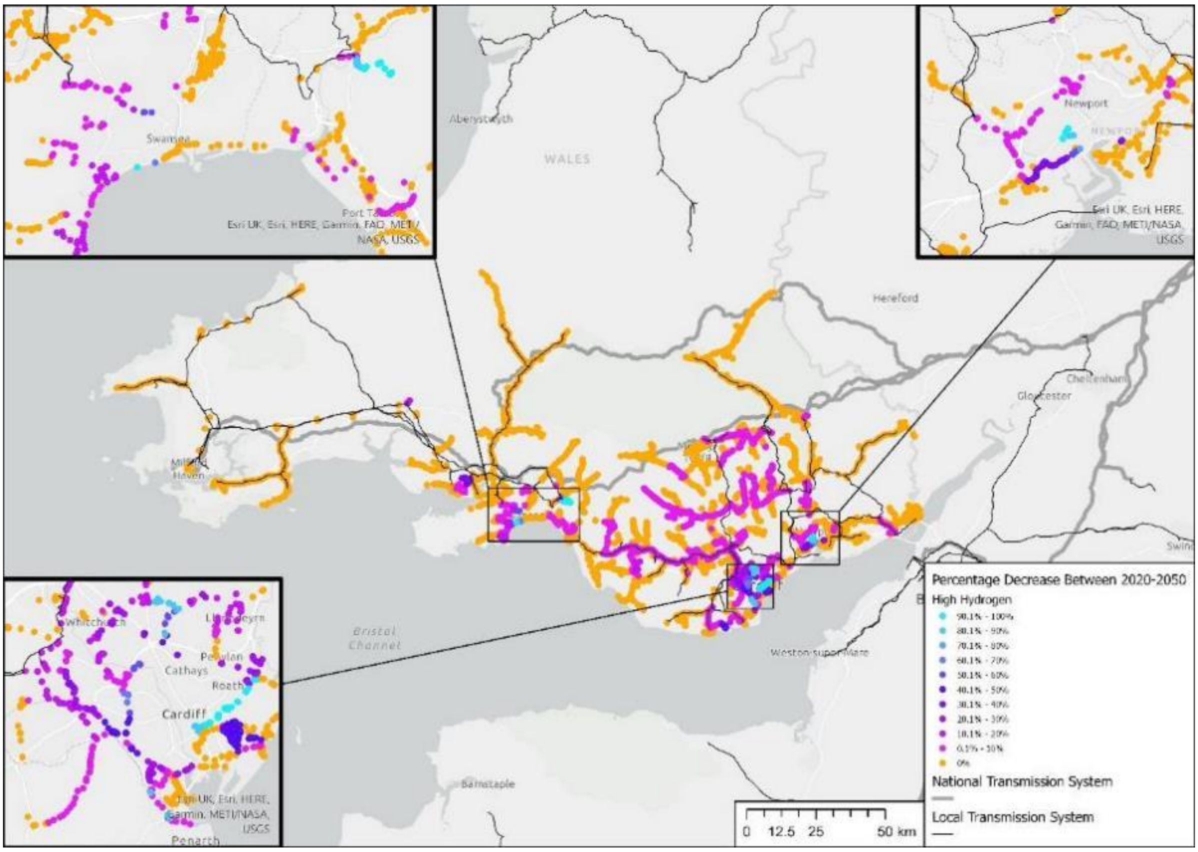


Figure 26.55. % Change in the Domestic and commercial Meters – High Hydrogen in 2050



27. SUB-REGIONAL PLANS (ELE / BAL / HYD) – SOUTH WEST

27.1. WECA, GLOUCESTER, WILTSHIRE, AND SOMERSET

27.1.1. HIGH ELECTRIFICATION (ELE)

For High Electrification (ELE) according to the WWU scenario modelled in ESME Hydrogen production starts after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 27.1. South West Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

South West	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.0	0.0	0.3	7.0	19.1	15.2	11.5
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	0.0	1.9	14.5	9.4	8.4
Natural Gas Consumption from Distribution Network (TWh)	35.2	32.3	27.9	21.0	5.9	0.0	0.0

Figure 27.1. South West Distribution Network Use by Natural Gas and Hydrogen – High Electrification

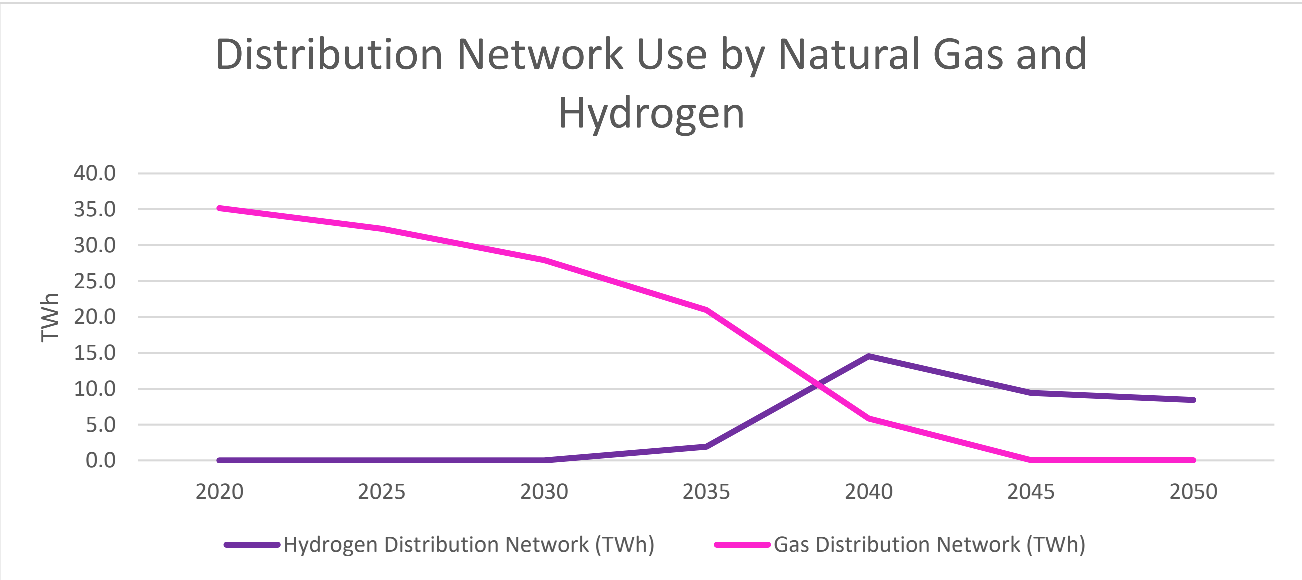


Table 27.2. South West Meters Converted per 5 Year Cycle – High Electrification

South West	Number of Meters Converted per 5 Year Cycle – High Electrification						
	2020	2025	2030	2035	2040	2045	2050
Cirencester	0	0	0	0	42055	0	0
Easton Grey	0	0	0	0	88052	0	0
Evesham	0	0	0	0	38112	0	0
Fiddington	0	0	0	0	141935	0	0
Ilchester	0	0	0	0	169533	0	0
Littleton Drew	0	0	0	0	6571	0	0
Seabank	0	0	0	268099	0	0	0
Pucklechurch	0	0	0	0	116965	0	0
Ross	0	0	0	0	23656	0	0
Total	0	0	0	268099	626880	0	0
Meters Converting per Week (40 Wks/Year)	0	0	0	1340	3134	0	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

In 2040 the number of meters requiring conversion is higher than the recommended figure of 2500 from the HYDROGEN1 Project, therefore either an additional conversion team will be required, or a number of meters scheduled for 2040 would have to be push back into 2045.

Figure 27.2. 2020 – 2030 High Electrification - Domestic and commercial Meters

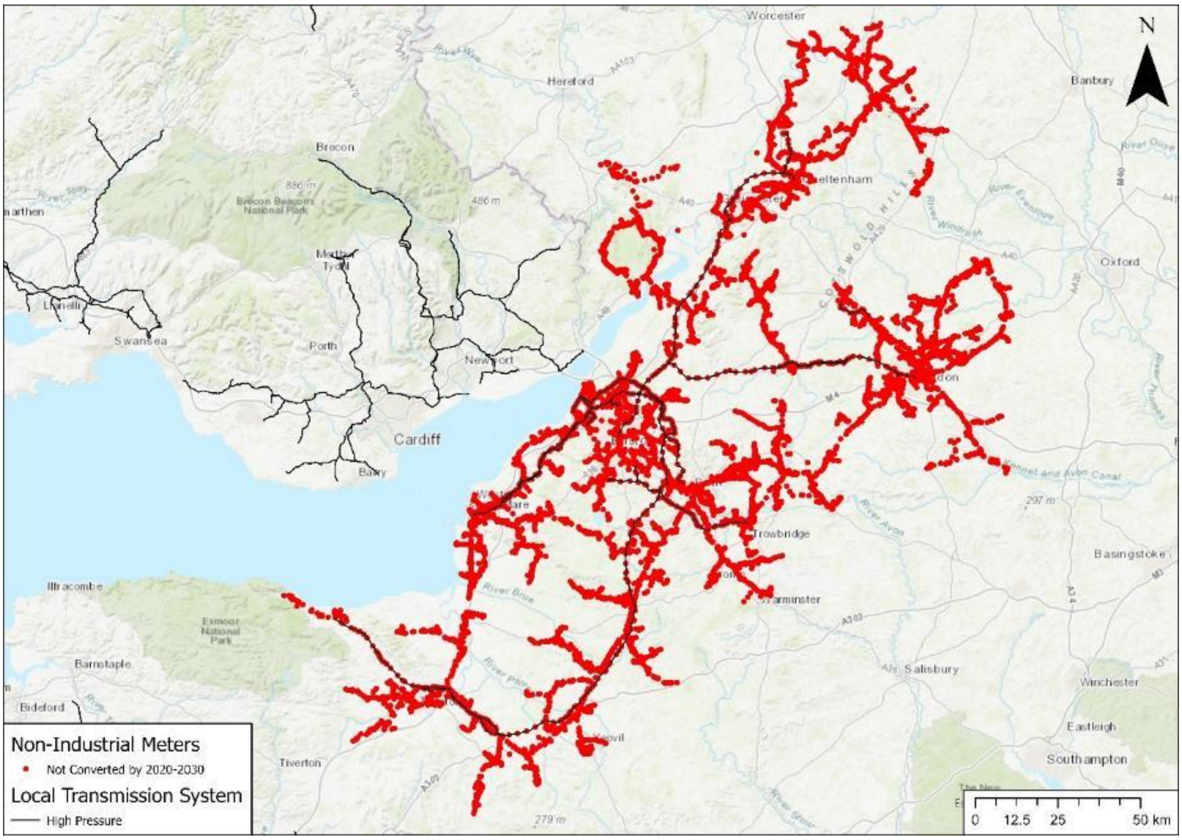


Figure 27.3. 2035 High Electrification - Domestic and commercial Meters

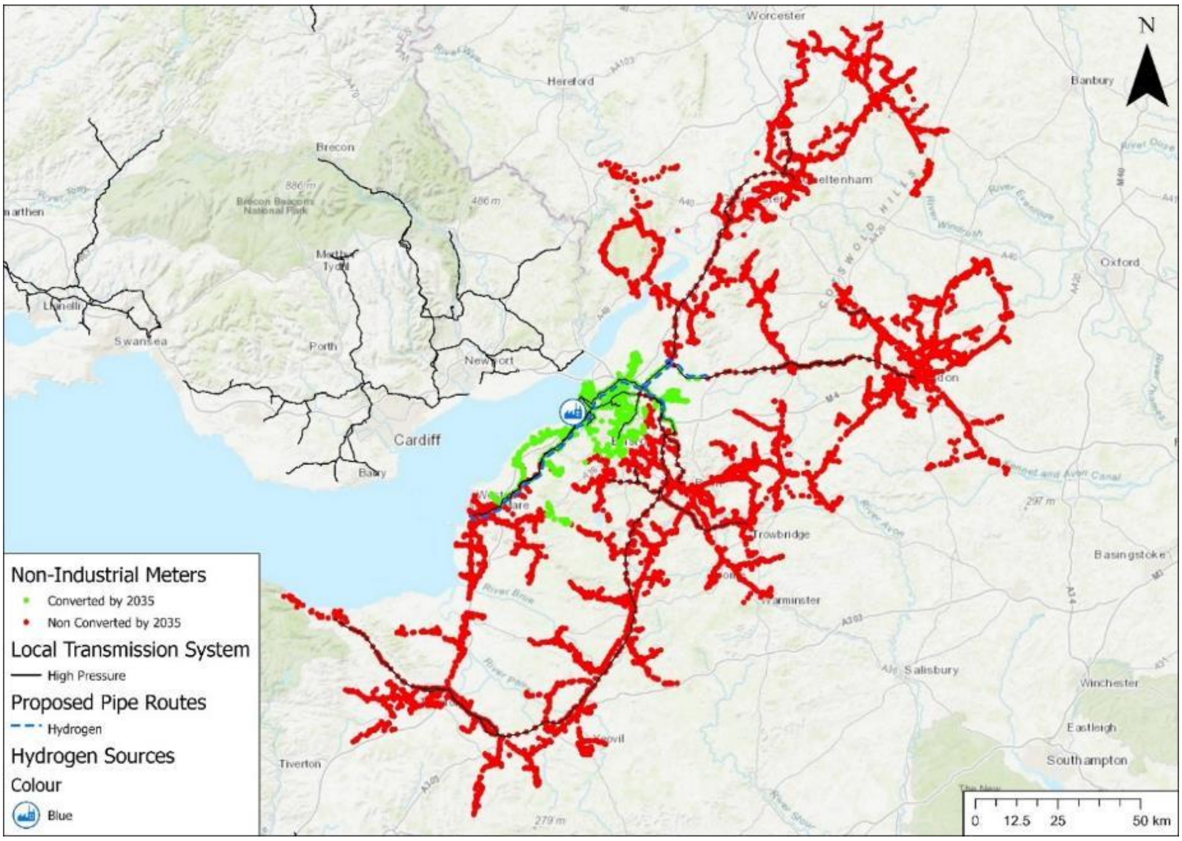


Figure 27.4. 2040 – 2050 High Electrification - Domestic and commercial Meters

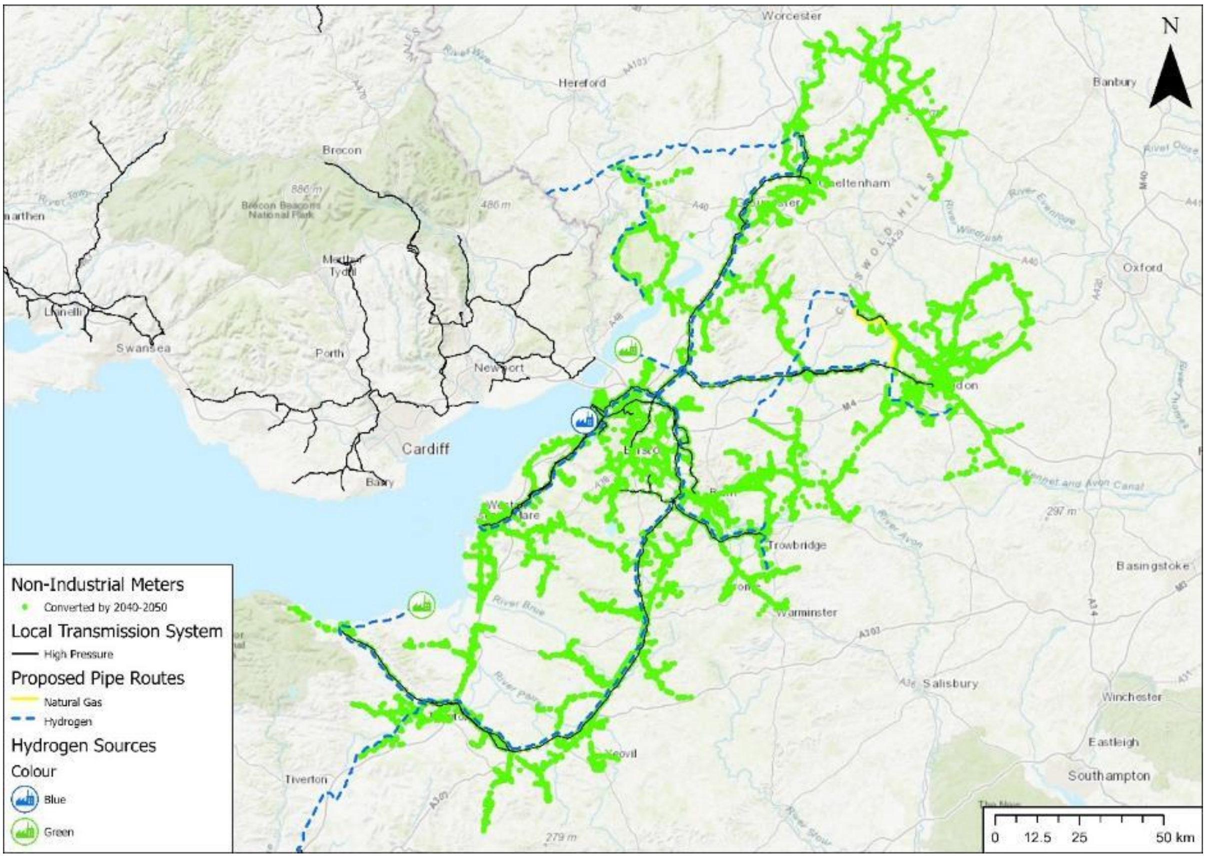
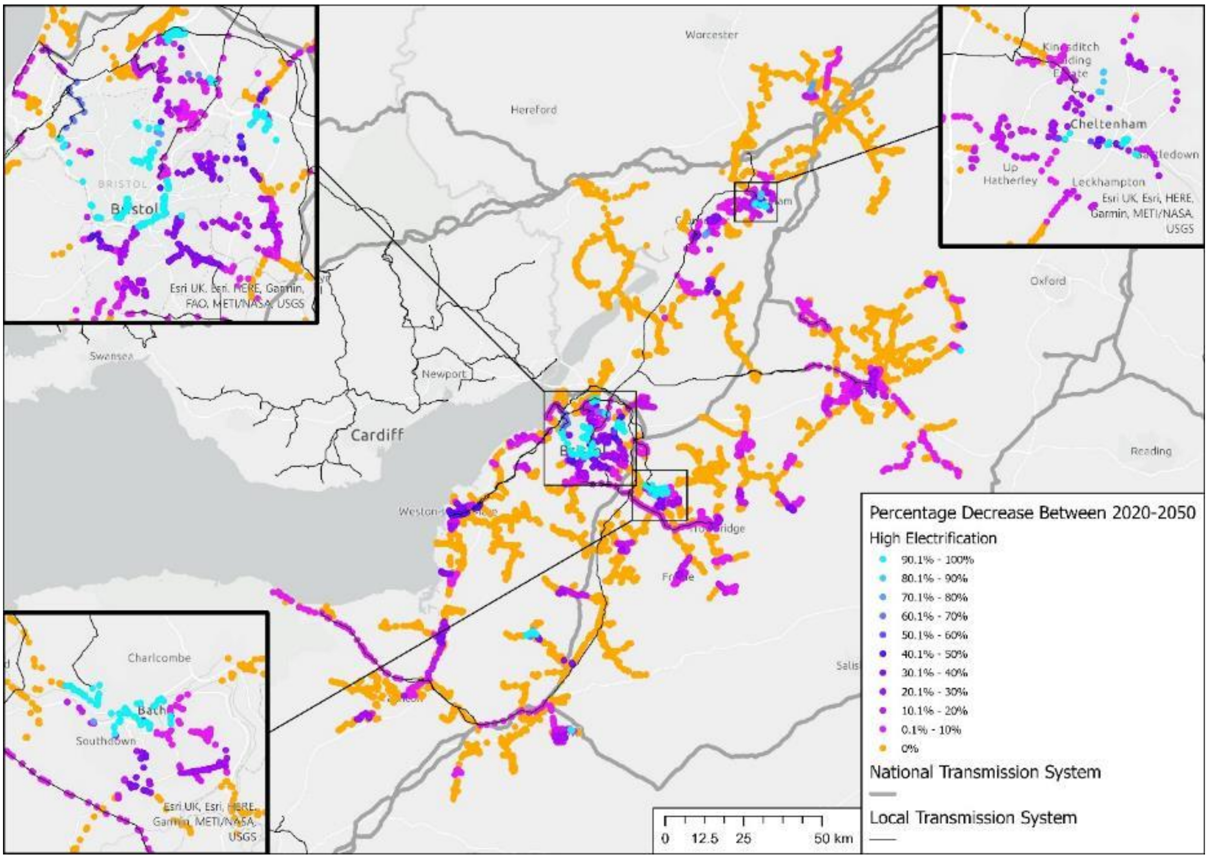


Figure 27.5. % Change in the Domestic and commercial Meters – High Electrification in 2050



27.1.2. BALANCED (BAL)

For Balanced (BAL) according to the WWU scenario modelled in ESME Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 27.3. South West Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

South West	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.0	0.0	4.7	14.3	15.0	13.9	13.9
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	3.2	9.8	23.3	24.6	18.8
Natural Gas Consumption from Distribution Network (TWh)	33.4	34.1	22.8	20.1	4.0	0.0	0.0

Figure 27.6. South West Distribution Network Use by Natural Gas and Hydrogen – Balanced

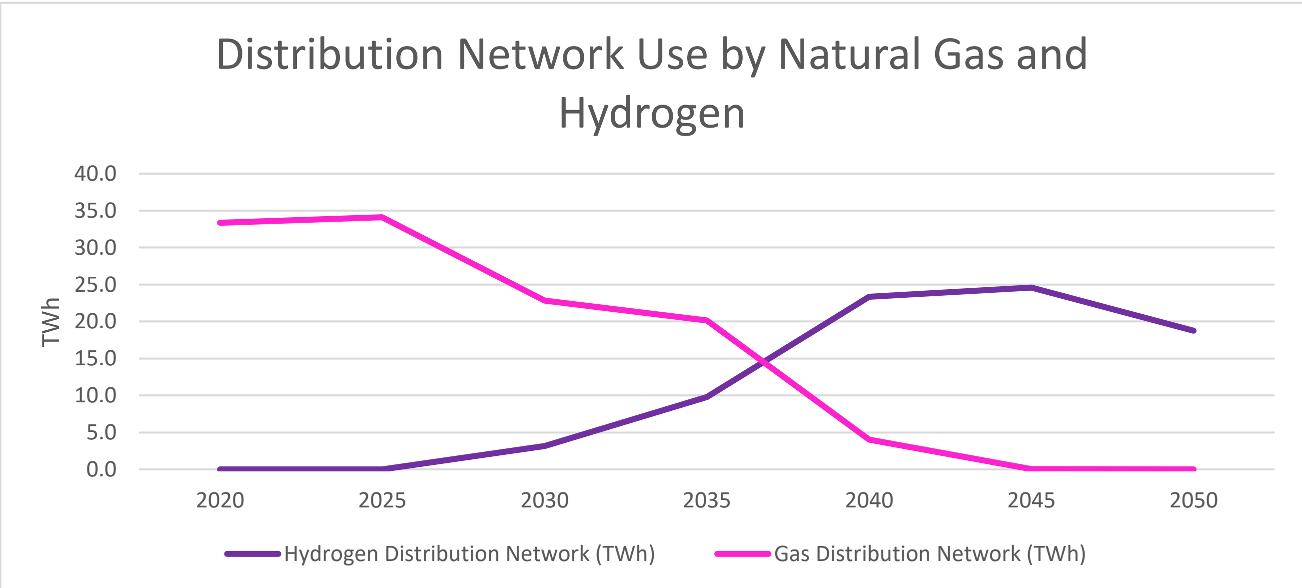


Table 27.4. South West Meters Converted per 5 Year Cycle – Balanced

South West	Number of Meters Converted per 5 Year Cycle – Balanced						
	2020	2025	2030	2035	2040	2045	2050
Cirencester	0	0	0	43450	0	0	0
Easton Grey	0	0	0	90973	0	0	0
Evesham	0	0	0	0	39377	0	0
Fiddington	0	0	0	2251	144393	0	0
Ilchester	0	0	0	0	175158	0	0
Littleton Drew	0	0	0	6789	0	0	0
Seabank	0	0	175035	101958	0	0	0
Pucklechurch	0	0	0	120845	0	0	0
Ross	0	0	0	0	24441	0	0
Total	0	0	175035	366267	383367	0	0
Meters Converting per Week (40 Wks/Year)	0	0	875	1831	1917	0	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

Figure 27.7. 2020 – 2025 Balanced - Domestic and commercial Meters

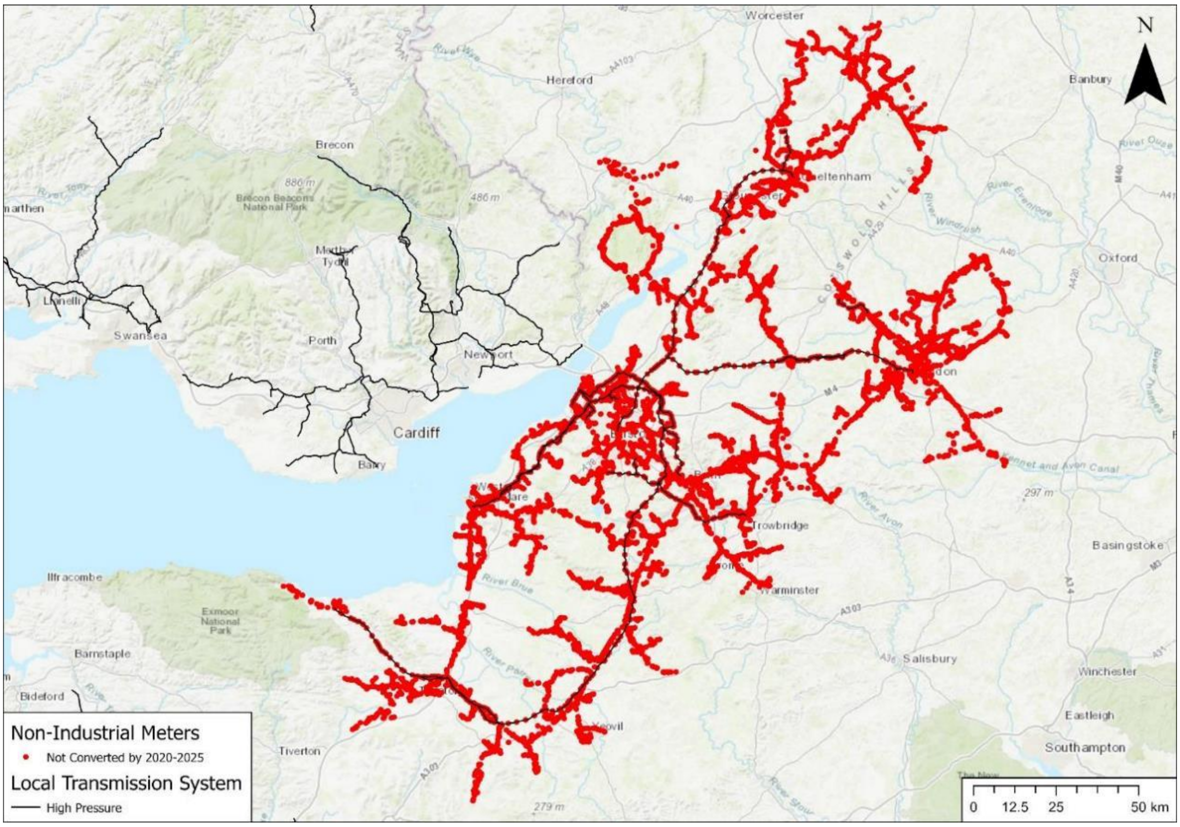


Figure 27.8. 2030 Balanced - Domestic and commercial Meters

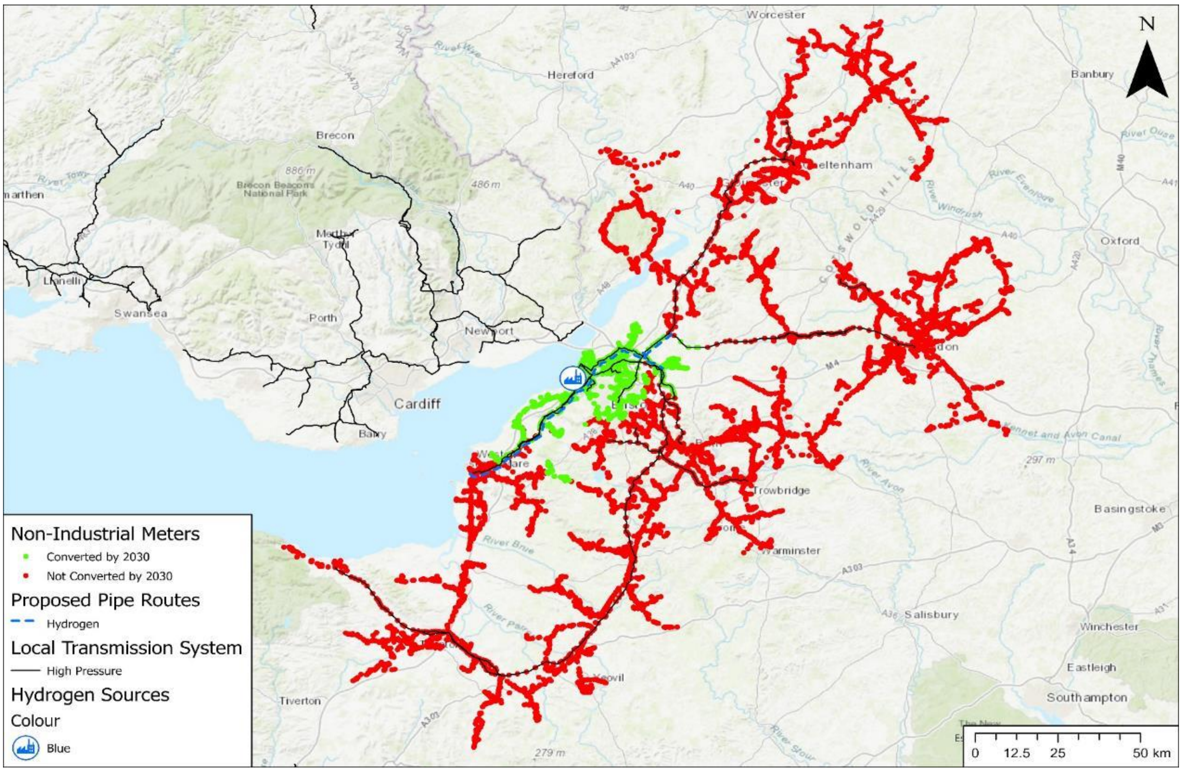


Figure 27.9. 2035 Balanced - Domestic and commercial Meters

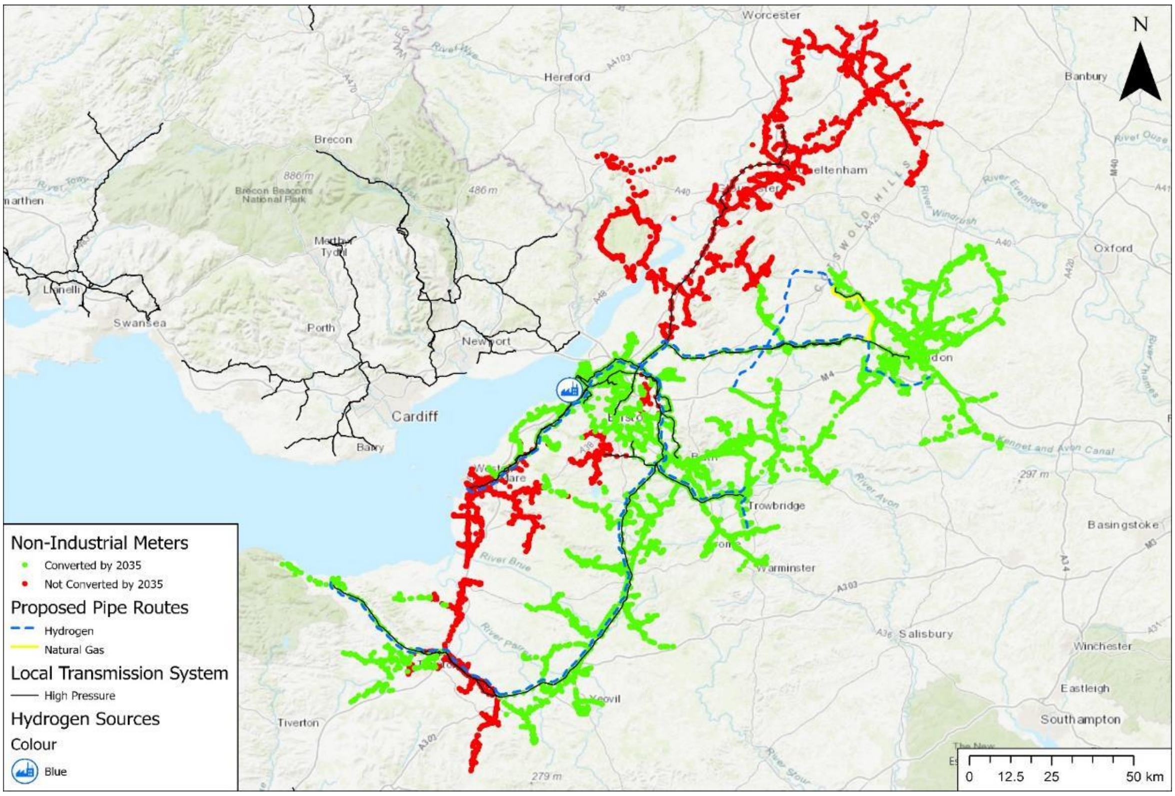


Figure 27.10. 2040 – 2050 Balanced - Domestic and commercial Meters

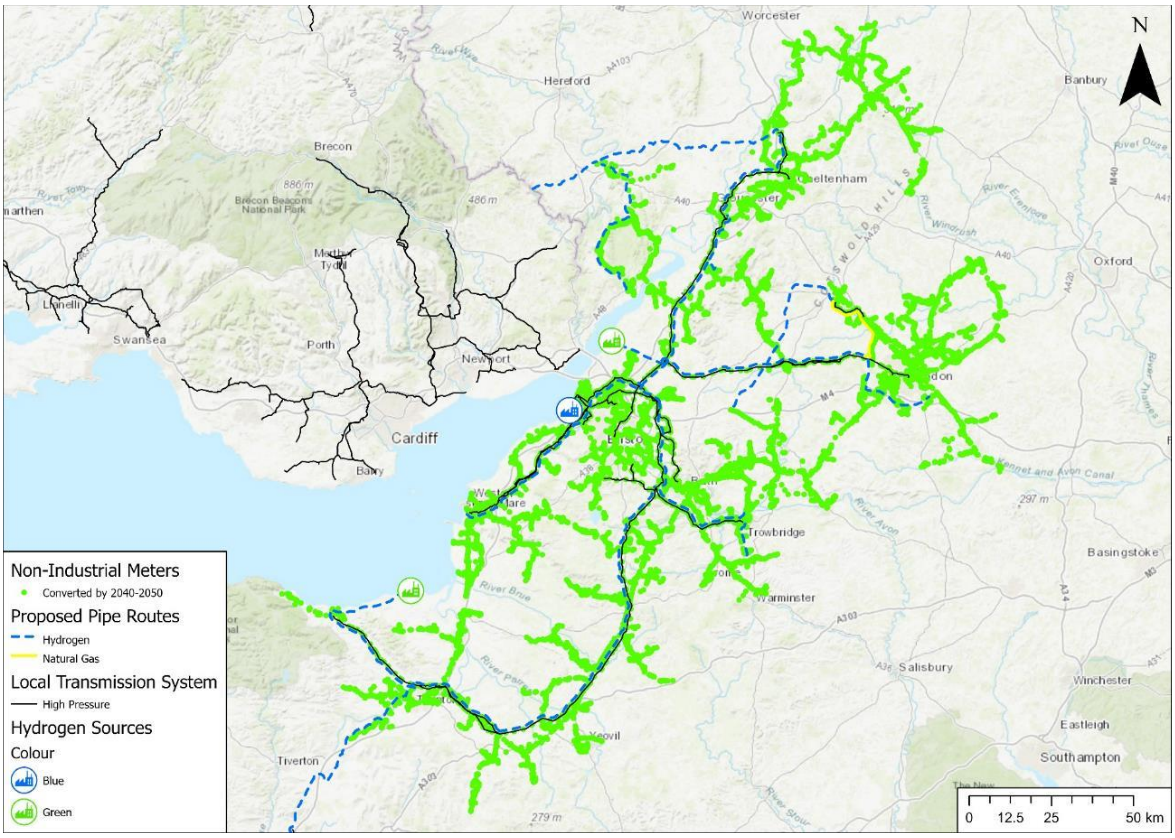
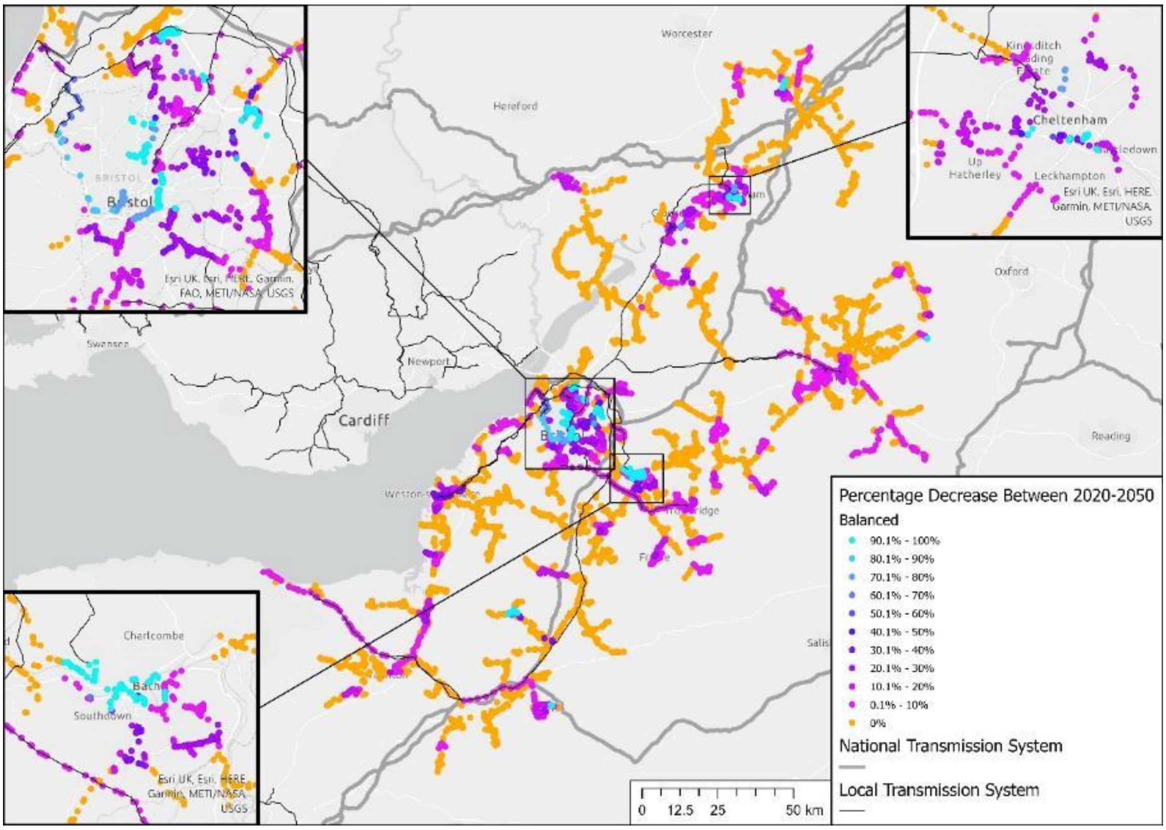


Figure 27.11. % Change in the Domestic and commercial Meters – Balanced in 2050



27.1.3. HIGH HYDROGEN (HYD)

For High Hydrogen (HYD) according to the WWU scenario modelled in ESME Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 27.5. South West Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

South West	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.2	0.2	4.3	15.3	17.4	15.8	15.9
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	4.2	11.4	24.0	24.9	21.7
Natural Gas Consumption from Distribution Network (TWh)	34.8	36.5	24.3	19.8	4.4	0.0	0.0

Figure 27.12. South West Distribution Network Use by Natural Gas and Hydrogen – High Hydrogen

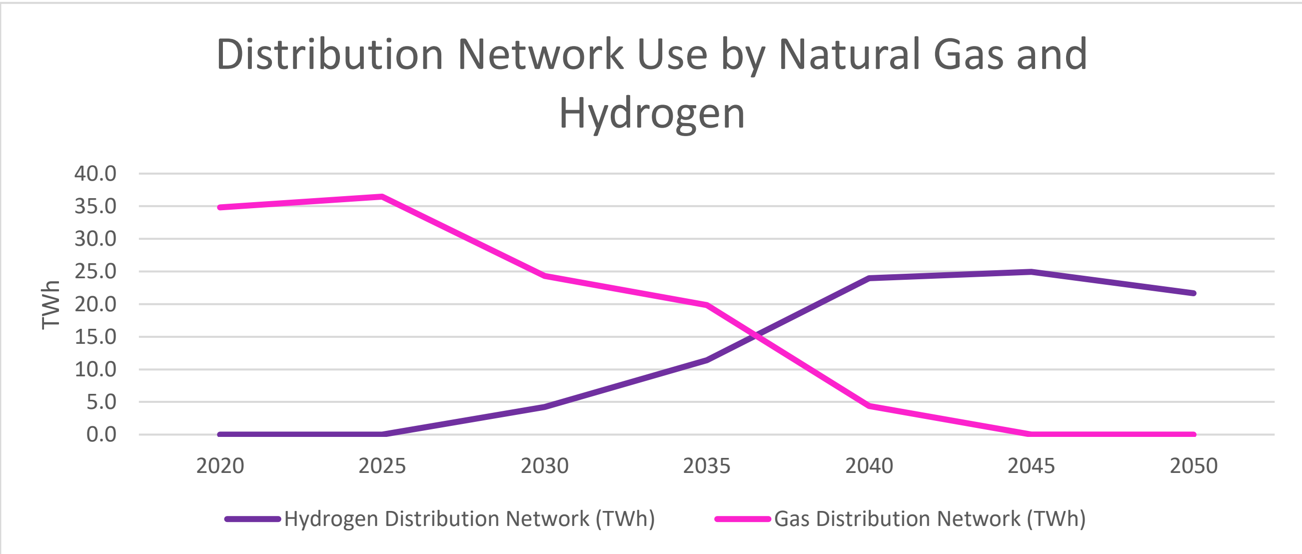


Table 27.6. South West Meters Converted per 5 Year Cycle – High Hydrogen

South West	Number of Meters Converted per 5 Year Cycle – High Hydrogen						
	2020	2025	2030	2035	2040	2045	2050
Cirencester	0	0	0	43450	0	0	0
Easton Grey	0	0	0	90973	0	0	0
Evesham	0	0	0	0	39377	0	0
Fiddington	0	0	0	81169	65475	0	0
Ilchester	0	0	0	0	175158	0	0
Littleton Drew	0	0	0	6789	0	0	0
Seabank	0	0	230672	46321	0	0	0
Pucklechurch	0	0	0	120845	0	0	0
Ross	0	0	0	0	24441	0	0
Total	0	0	230672	389548	304450	0	0
Meters Converting per Week (40 Wks/Year)	0	0	1153	1948	1522	0	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

Figure 27.13. 2020 – 2025 High Hydrogen - Domestic and commercial Meters

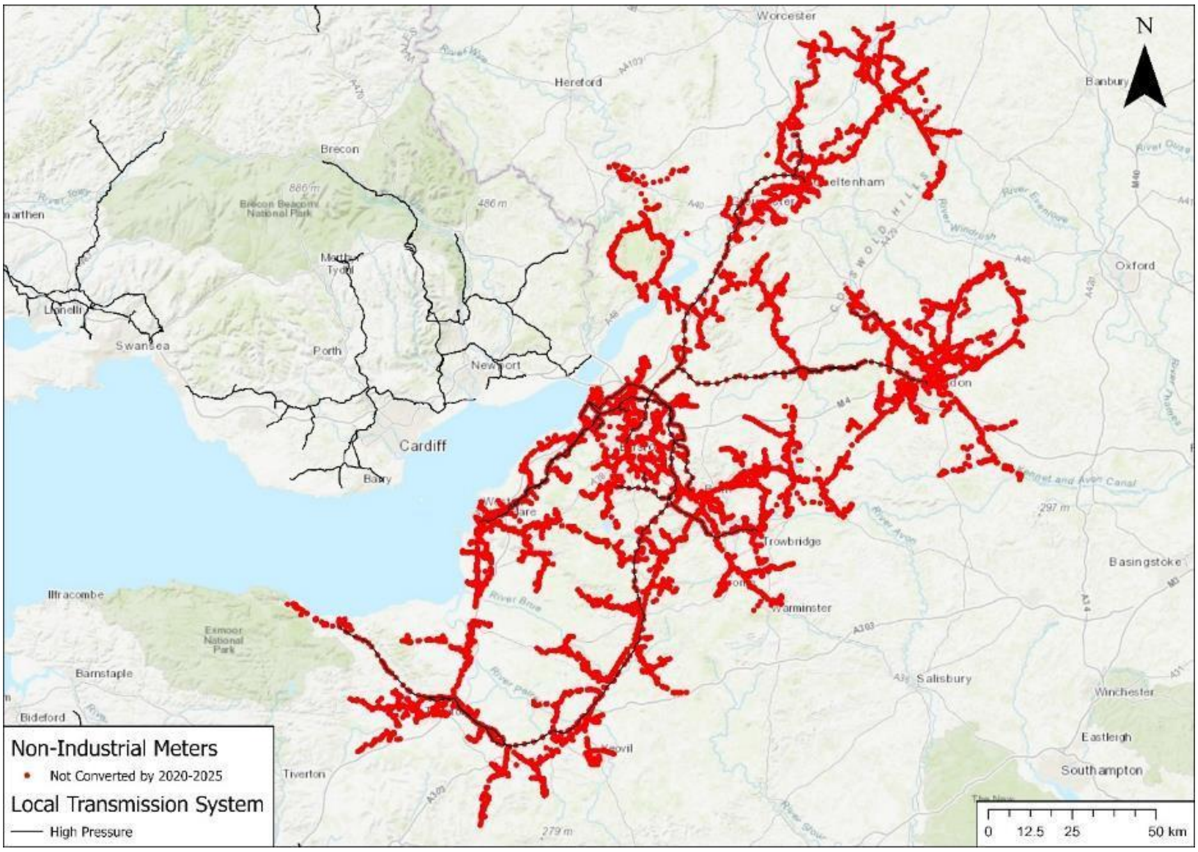


Figure 27.14. 2030 High Hydrogen - Domestic and commercial Meters

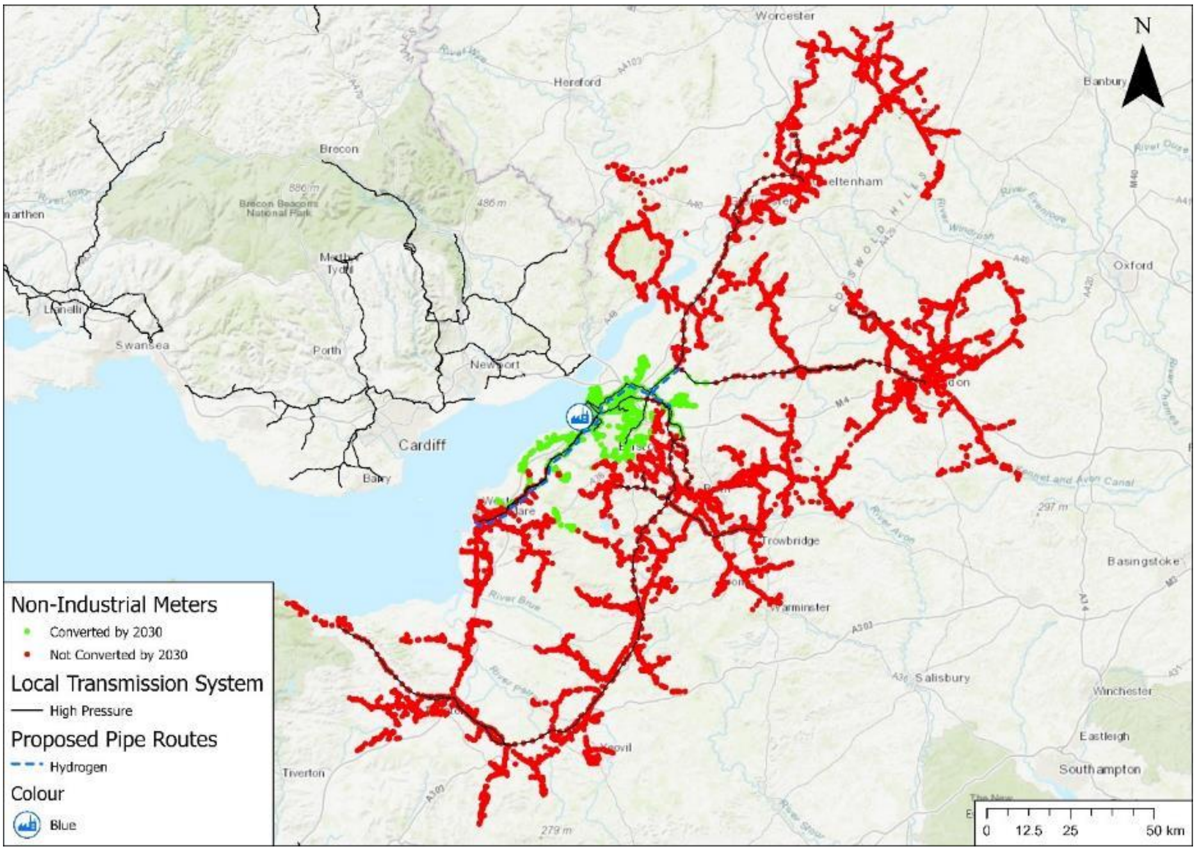


Figure 27.15. 2035 High Hydrogen - Domestic and commercial Meters

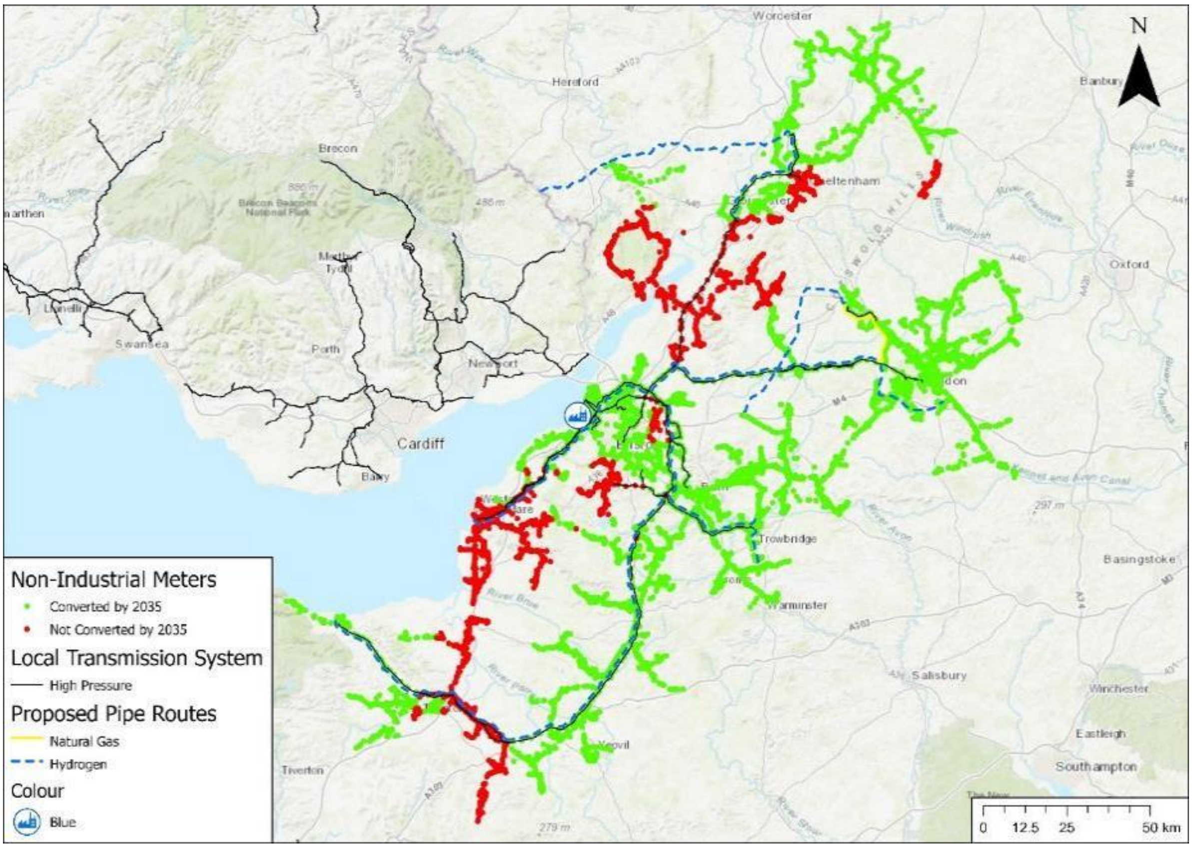


Figure 27.16. 2040 – 2050 High Hydrogen - Domestic and commercial Meters

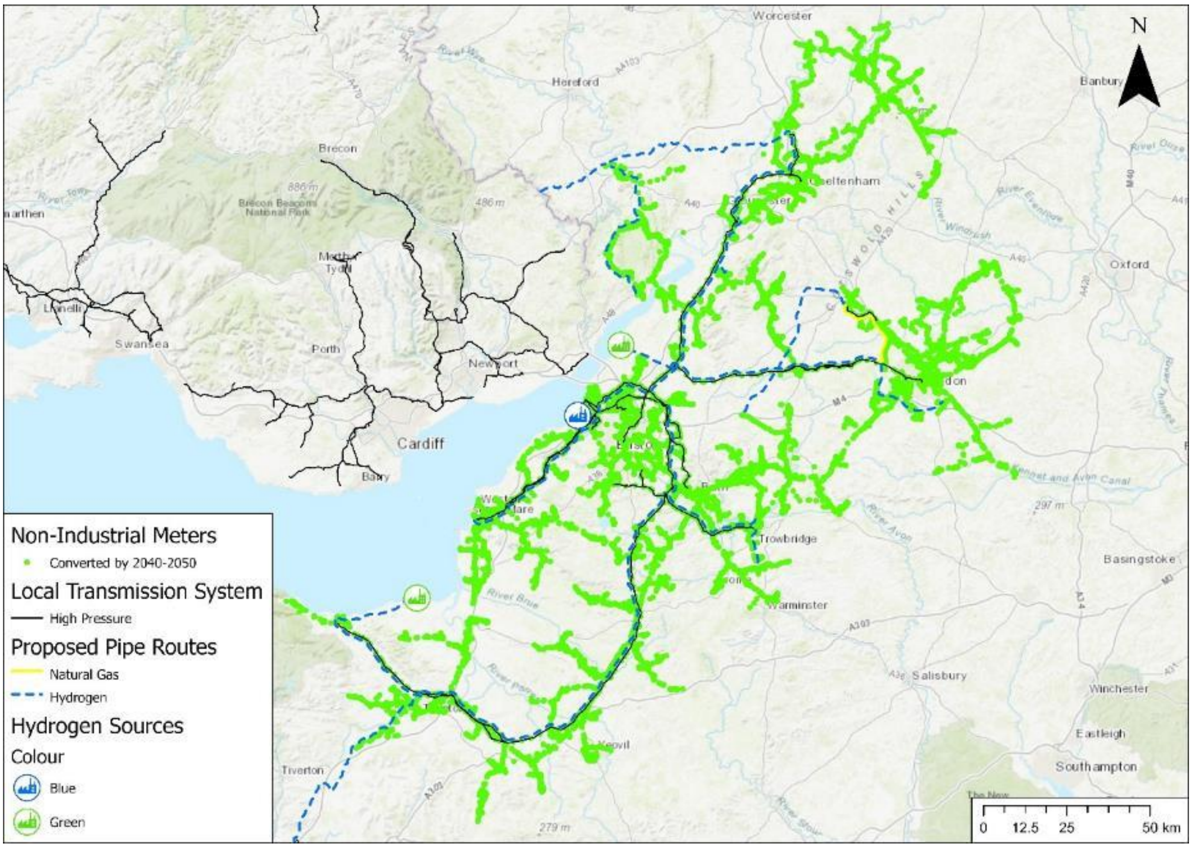
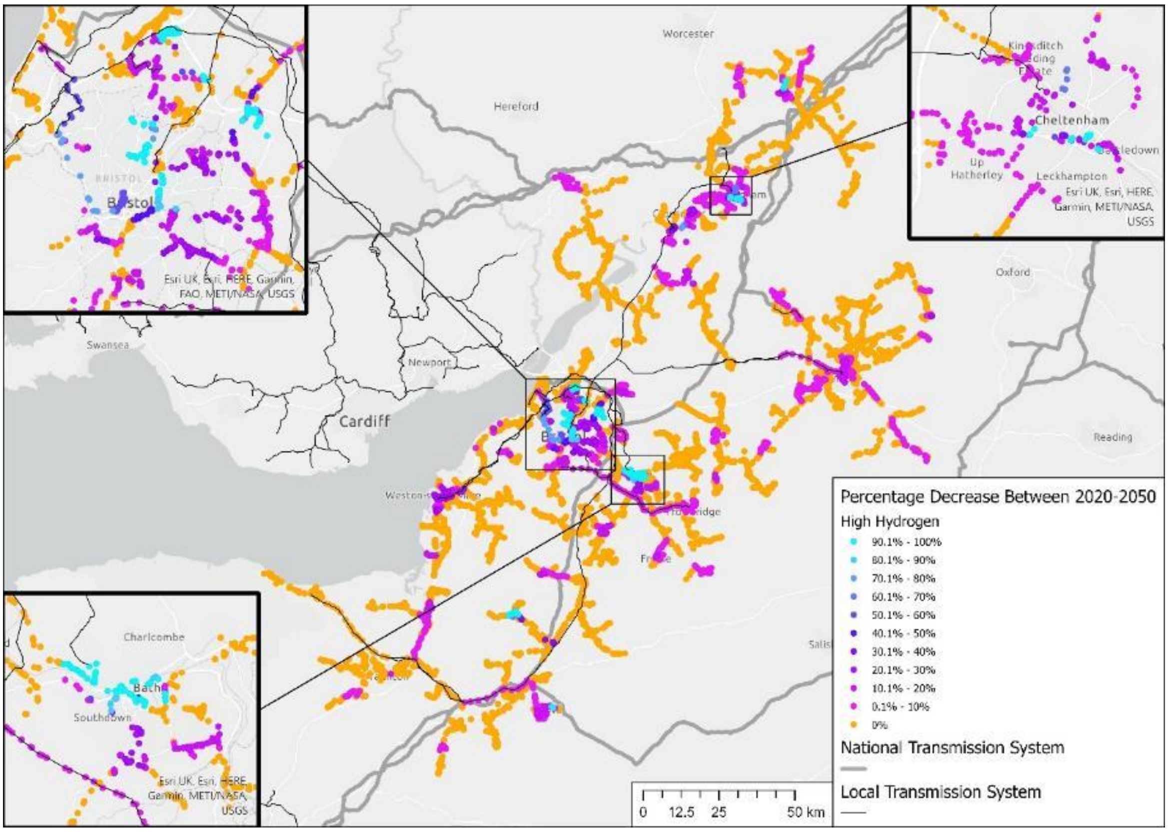


Figure 27.17. % Change in the Domestic and commercial Meters – High Hydrogen in 2050



27.2. DEVON

27.2.1. HIGH ELECTRIFICATION (ELE)

According to the High Electrification (ELE) WWU scenario modelled in ESME Hydrogen production starts after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 27.7. South West Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

South West	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.0	0.0	0.3	7.0	19.1	15.2	11.5
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	0.0	1.9	14.5	9.4	8.4
Natural Gas Consumption from Distribution Network (TWh)	35.2	32.3	27.9	21.0	5.9	0.0	0.0

Figure 27.18. South West Distribution Network Use by Natural Gas and Hydrogen – High Electrification

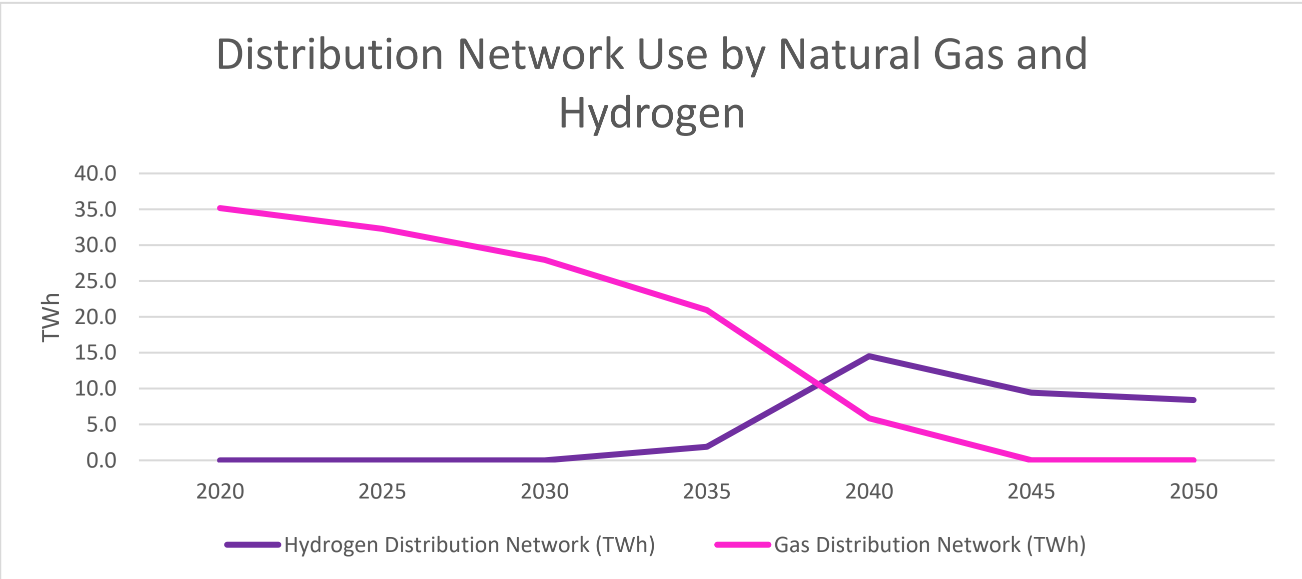


Table 27.8. South West Meters Converted per 5 Year Cycle – High Electrification

South West	Number of Meters Converted per 5 Year Cycle – High Electrification						
	2020	2025	2030	2035	2040	2045	2050
Aylesbeare	0	0	0	0	0	98566	0
Choakford	0	0	0	0	151135	0	0
Coffinswell	0	0	0	0	27598	0	0
Kenn	0	0	0	0	21637	120298	0
Total	0	0	0	0	200370	218864	0
Meters Converting per Week (40 Wks/Year)	0	0	0	0	1002	1094	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

In 2040 the number of meters requiring conversion is higher than the recommended figure of 2500 from the HYDROGEN1 Project, therefore either an additional conversion team will be required, or a number of meters scheduled for 2040 would have to be push back into 2045.

Figure 27.19. 2020 – 2035 High Electrification - Domestic and commercial Meters

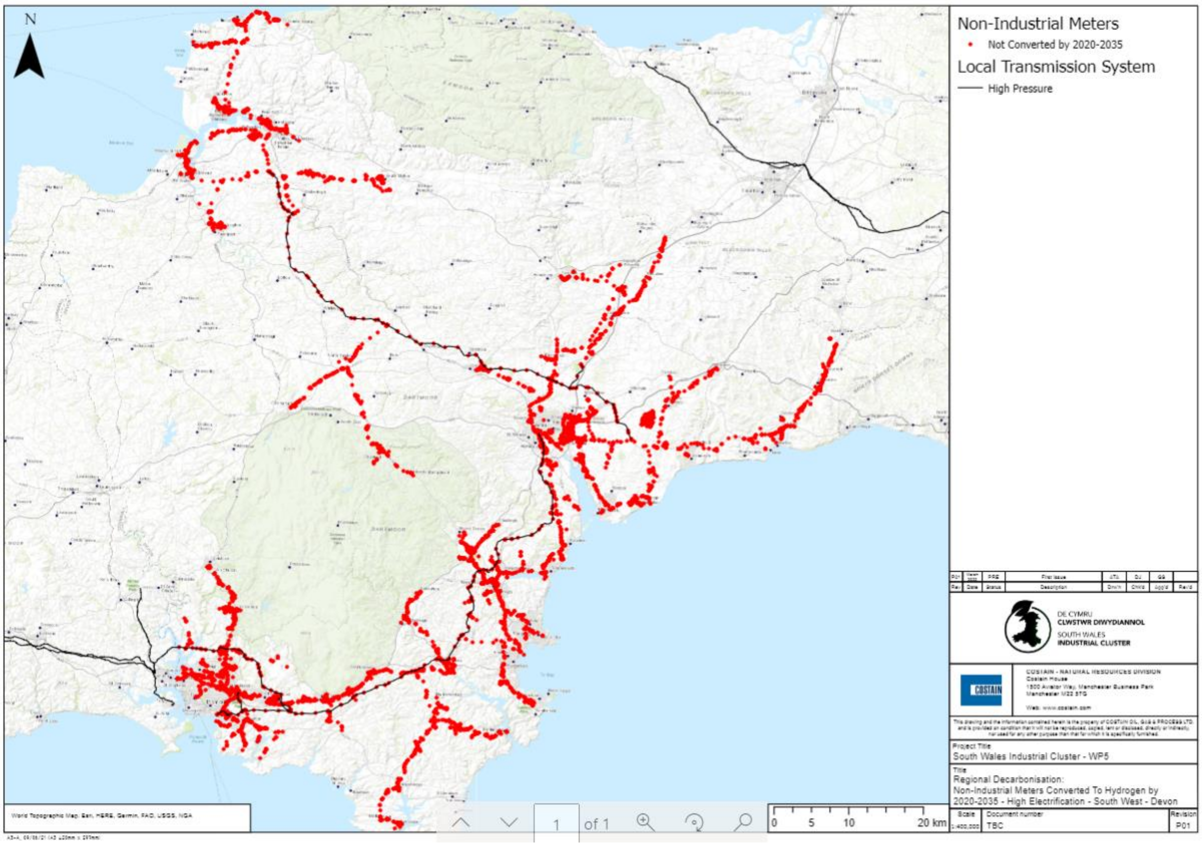


Figure 27.20. 2040 – 2050 High Electrification - Domestic and commercial Meters

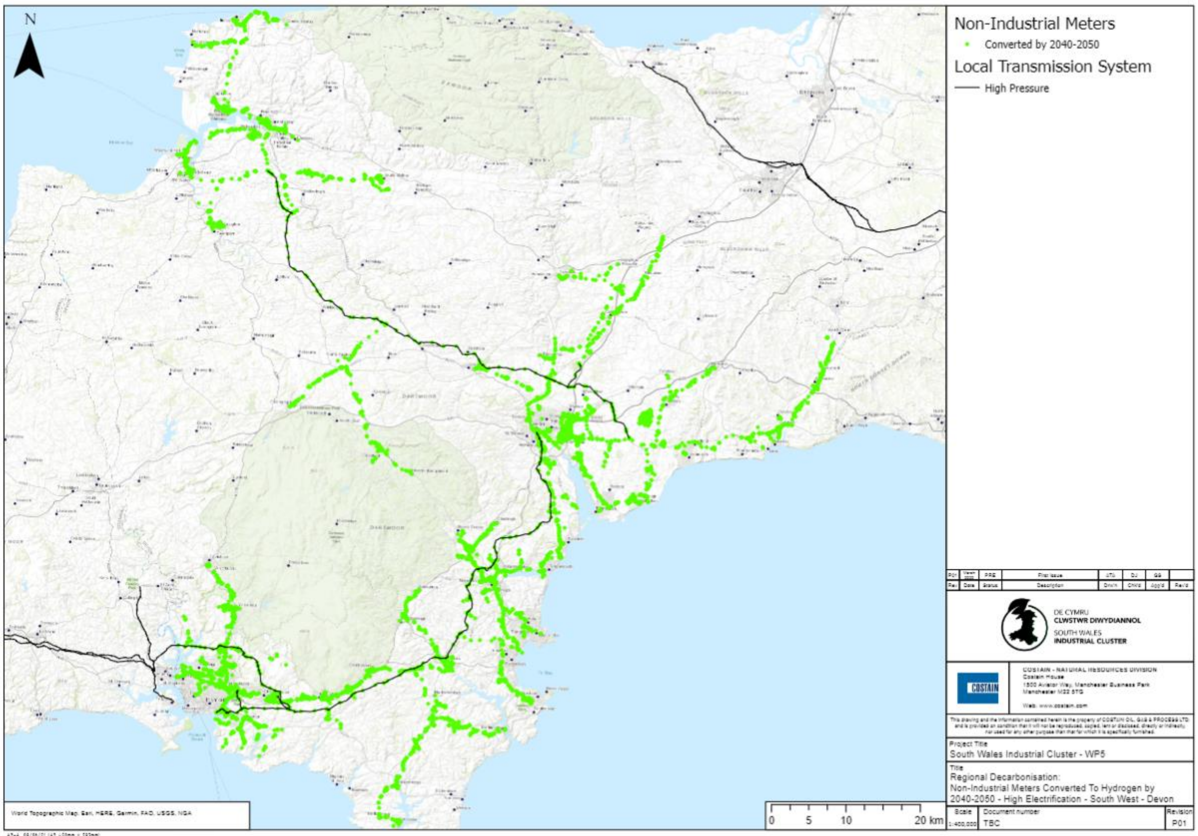
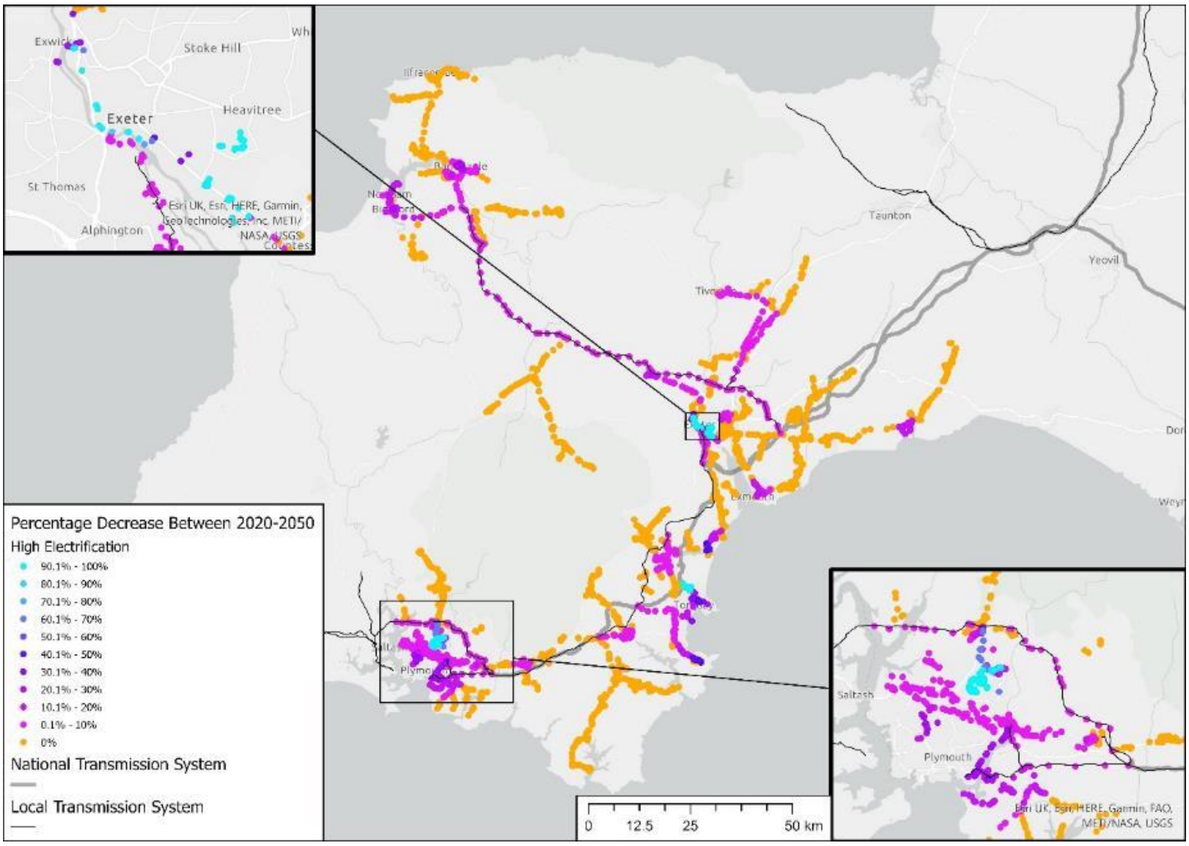


Figure 27.21. % Change in the Domestic and commercial Meters – High Electrification in 2050



27.2.2. BALANCED (BAL)

According to the Balanced (BAL) WWU scenario modelled in ESME Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 27.9. South West Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

South West	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.0	0.0	4.7	14.3	15.0	13.9	13.9
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	3.2	9.8	23.3	24.6	18.8
Natural Gas Consumption from Distribution Network (TWh)	33.4	34.1	22.8	20.1	4.0	0.0	0.0

Figure 27.22. South West Distribution Network Use by Natural Gas and Hydrogen – Balanced

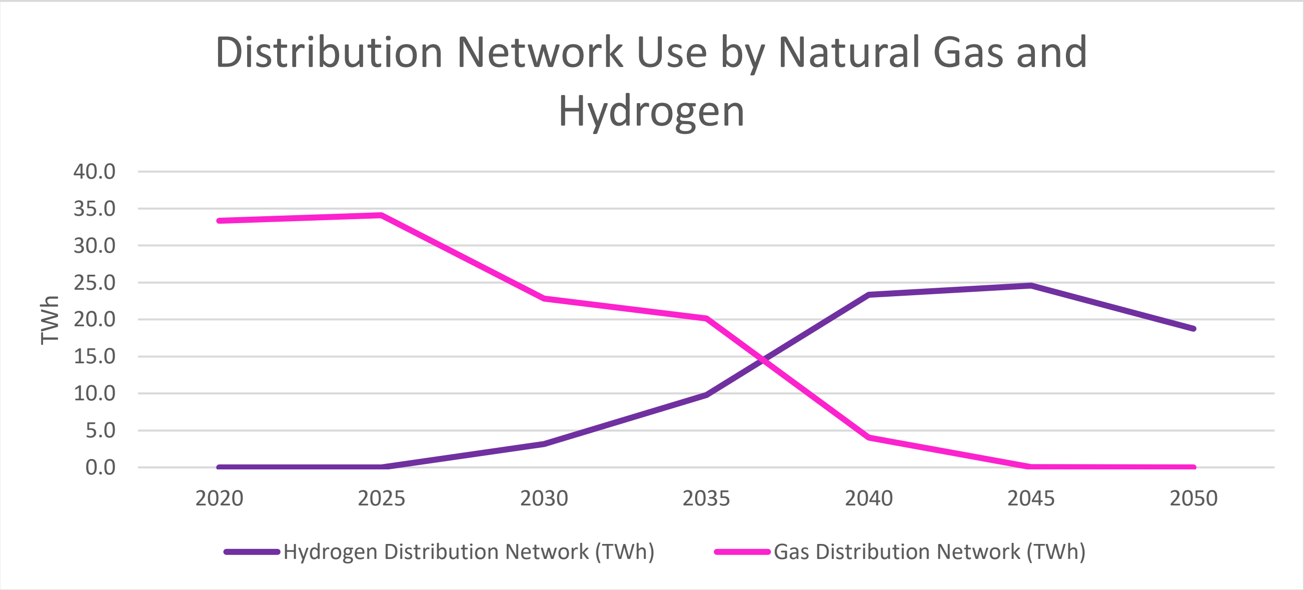


Table 27.10. South West Meters Converted per 5 Year Cycle – Balanced

South West	Number of Meters Converted per 5 Year Cycle – Balanced						
	2020	2025	2030	2035	2040	2045	2050
Aylesbeare	0	0	0	0	0	101836	0
Choakford	0	0	0	0	156148	0	0
Coffinswell	0	0	0	0	28514	0	0
Kenn	0	0	0	0	84120	62524	0
Total	0	0	0	0	268782	164359	0
Meters Converting per Week (40 Wks/Year)	0	0	0	0	1344	822	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

Figure 27.23. 2020 – 2030 Balanced - Domestic and commercial Meters

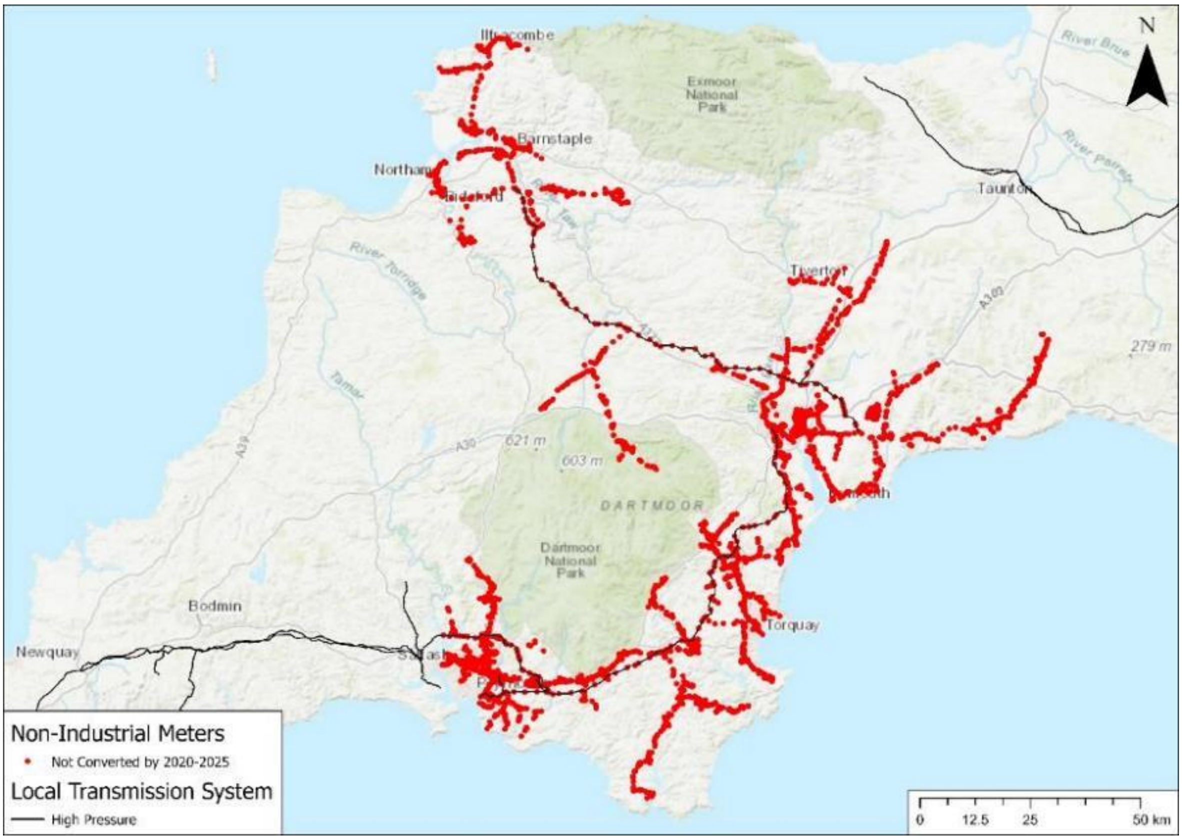


Figure 27.24. 2035 Balanced - Domestic and commercial Meters

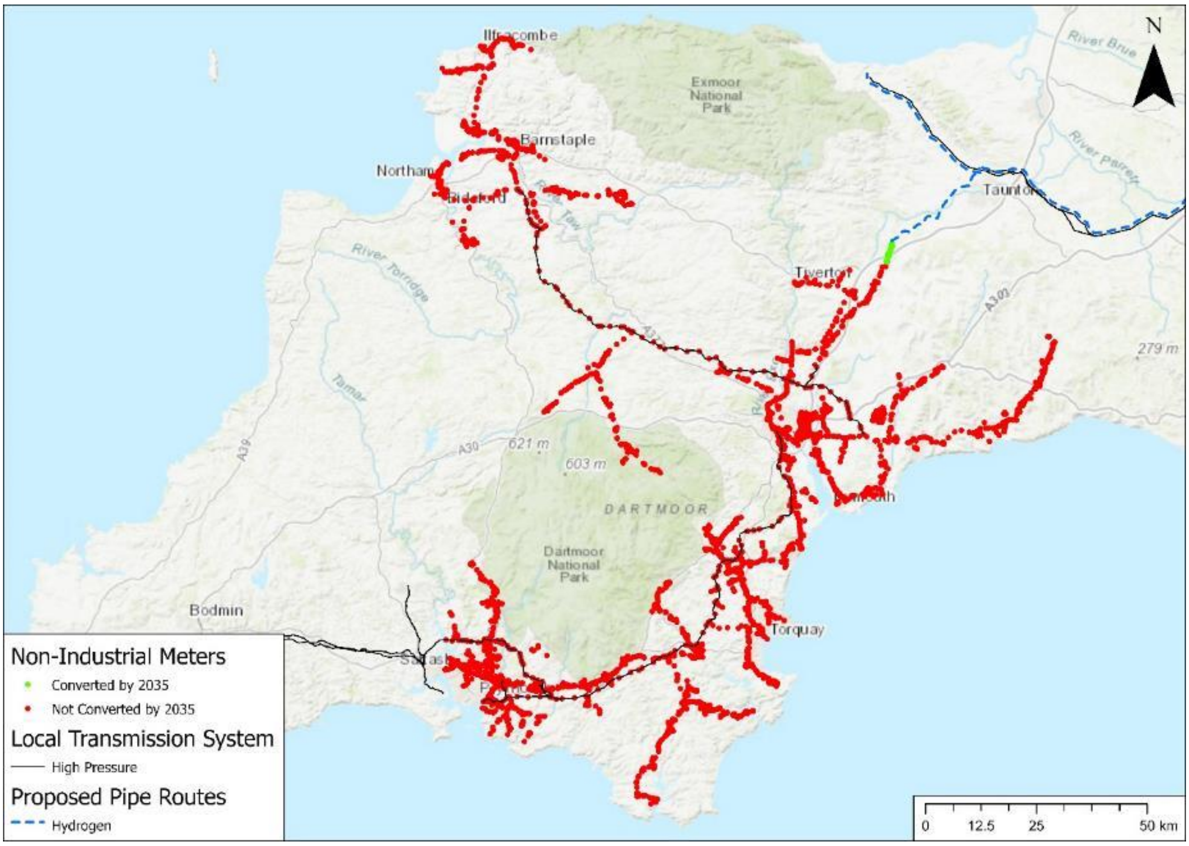


Figure 27.25. 2040 Balanced - Domestic and commercial Meters

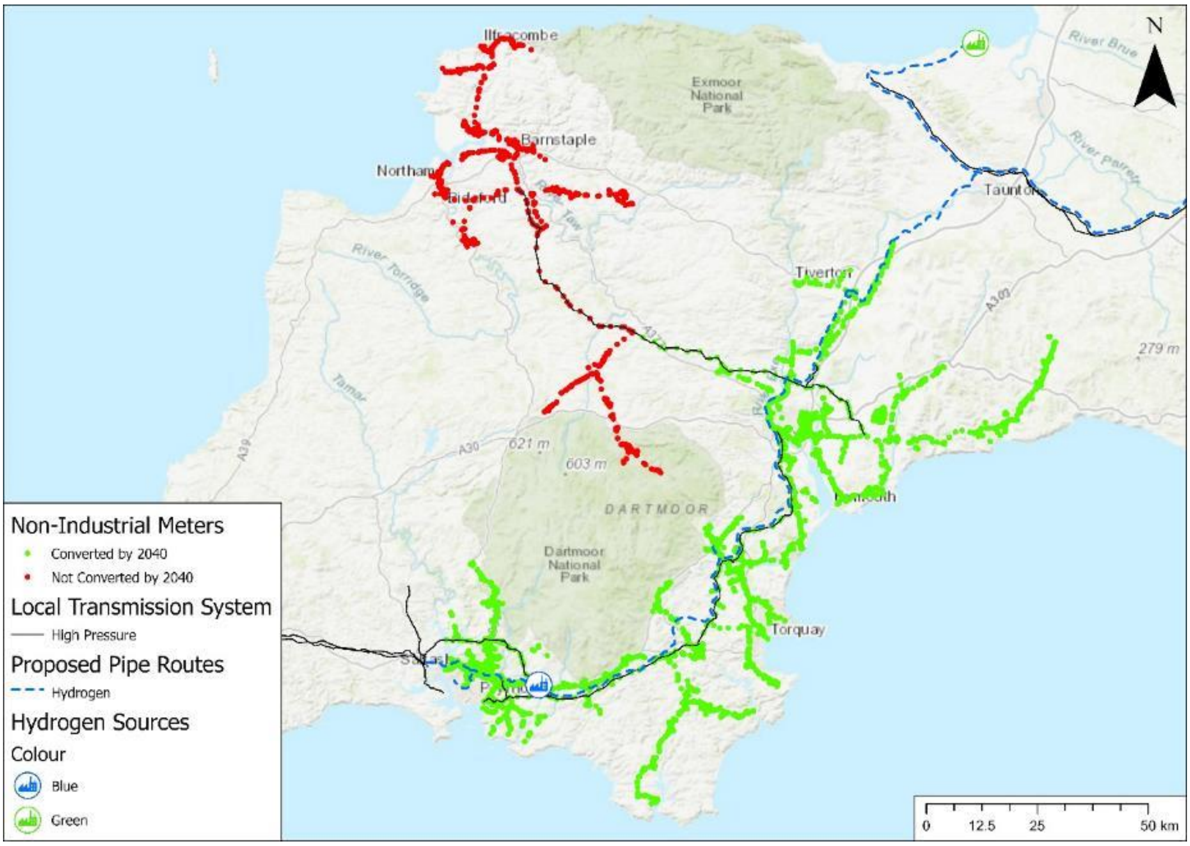


Figure 27.26. 2045 - 2050 Balanced - Domestic and commercial Meters

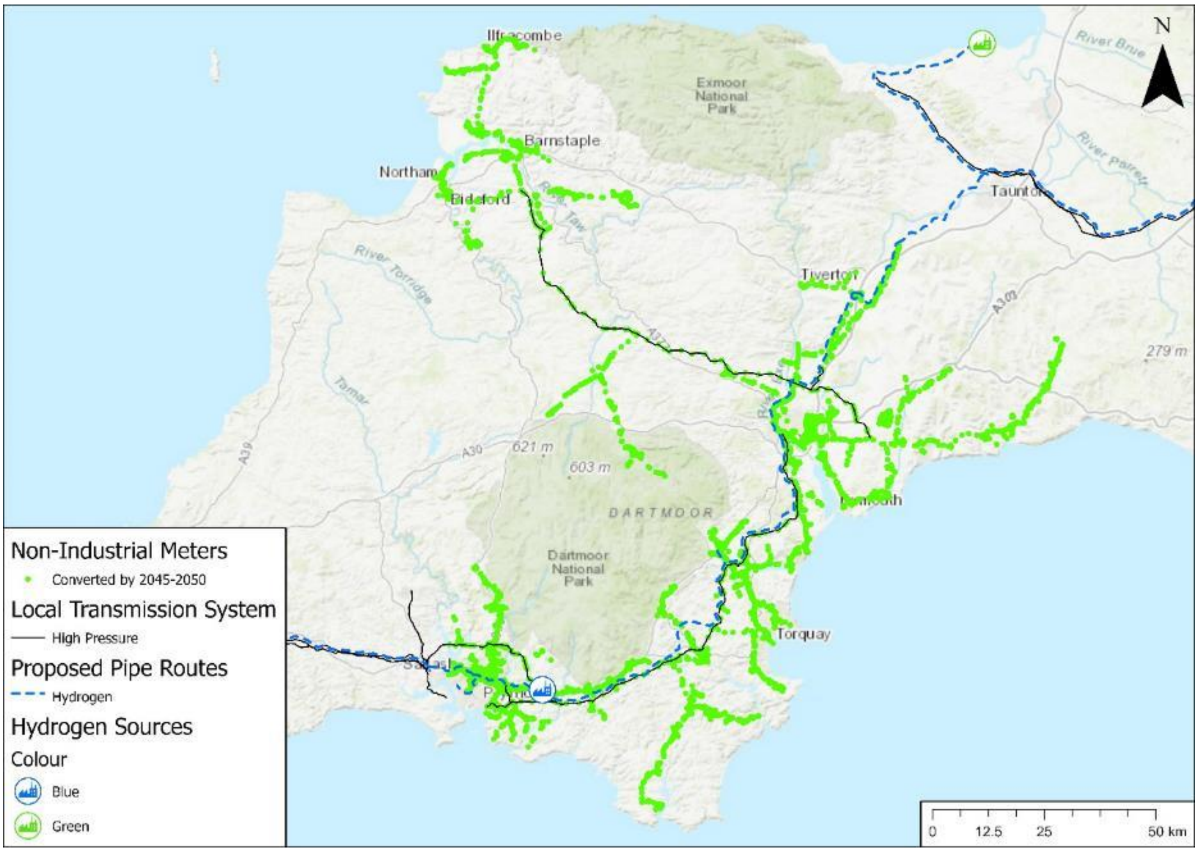
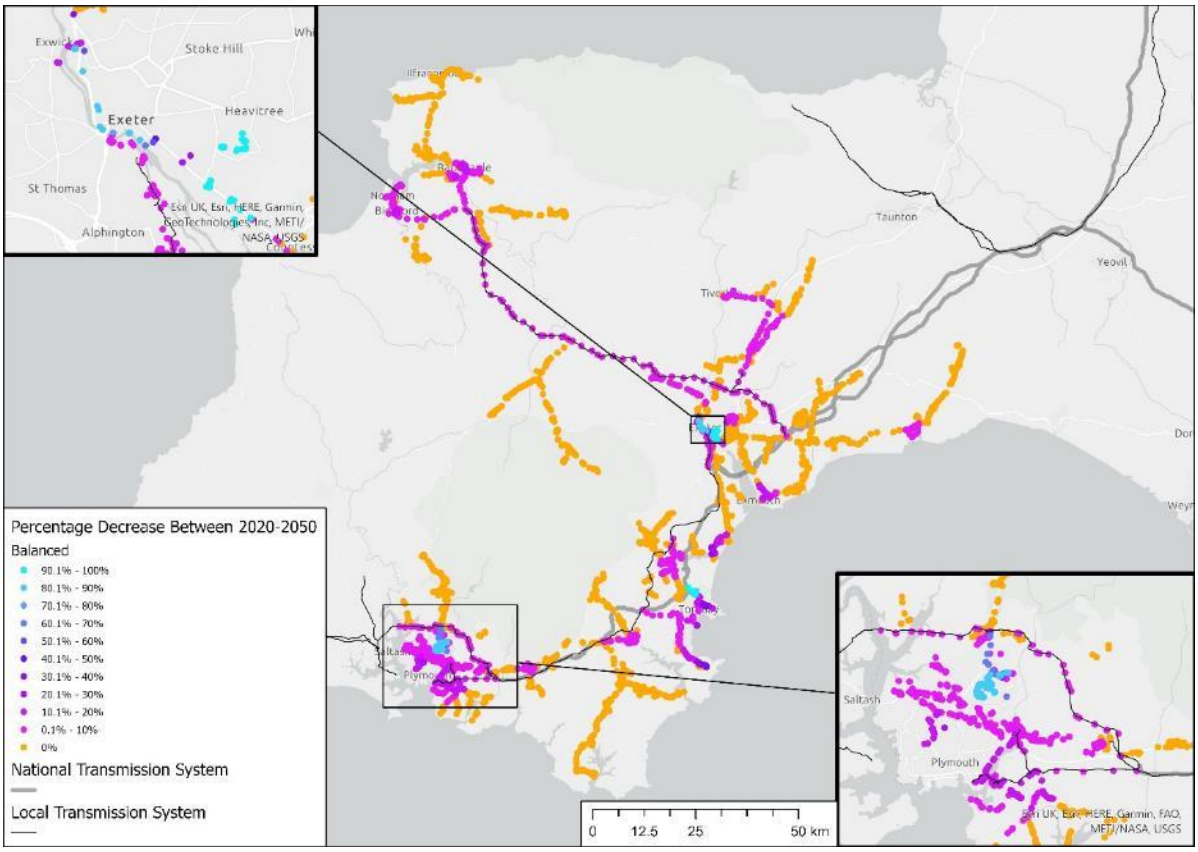


Figure 27.27. % Change in the Domestic and commercial Meters – Balanced in 2050



27.2.3. HIGH HYDROGEN (HYD)

For the High Hydrogen (HYD) WWU scenario modelled in ESME Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 27.11. South West Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

South West	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.2	0.2	4.3	15.3	17.4	15.8	15.9
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	4.2	11.4	24.0	24.9	21.7
Natural Gas Consumption from Distribution Network (TWh)	34.8	36.5	24.3	19.8	4.4	0.0	0.0

Figure 27.28. South West Distribution Network Use by Natural Gas and Hydrogen – High Hydrogen

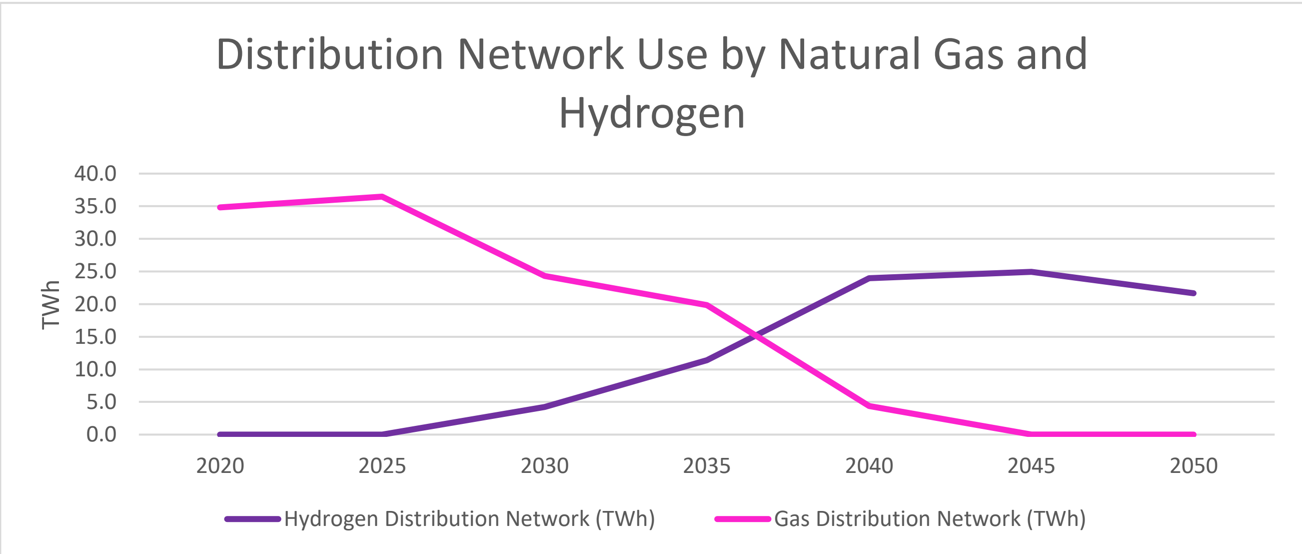


Table 27.12. South West Meters Converted per 5 Year Cycle – High Hydrogen

South West	Number of Meters Converted per 5 Year Cycle – High Hydrogen						
	2020	2025	2030	2035	2040	2045	2050
Aylesbeare	0	0	0	0	0	101836	0
Choakford	0	0	0	0	156148	0	0
Coffinswell	0	0	0	0	28514	0	0
Kenn	0	0	0	0	76844	69800	0
Total	0	0	0	0	261506	171636	0
Meters Converting per Week (40 Wks/Year)	0	0	0	0	1308	858	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

Figure 27.29. 2020 – 2030 High Hydrogen - Domestic and commercial Meters

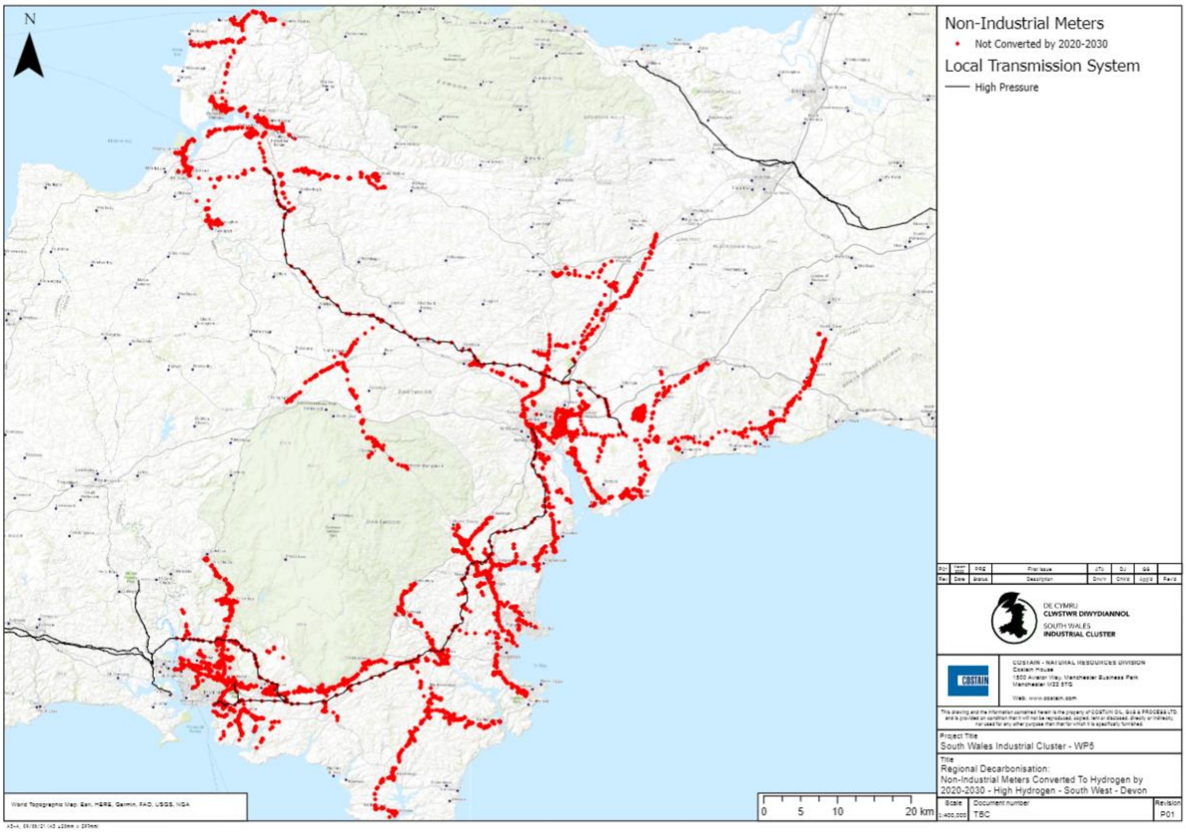


Figure 27.30. 2035 High Hydrogen - Domestic and commercial Meters

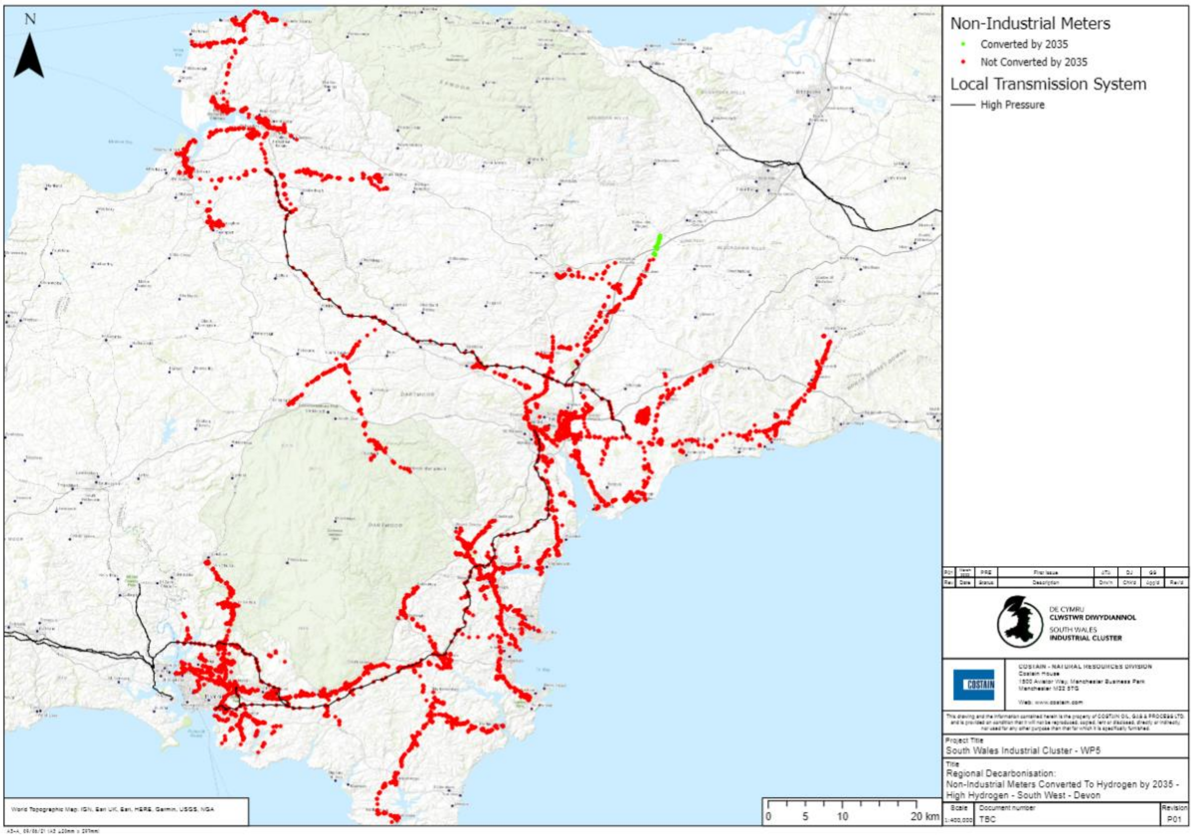


Figure 27.31. 2040 High Hydrogen - Domestic and commercial Meters

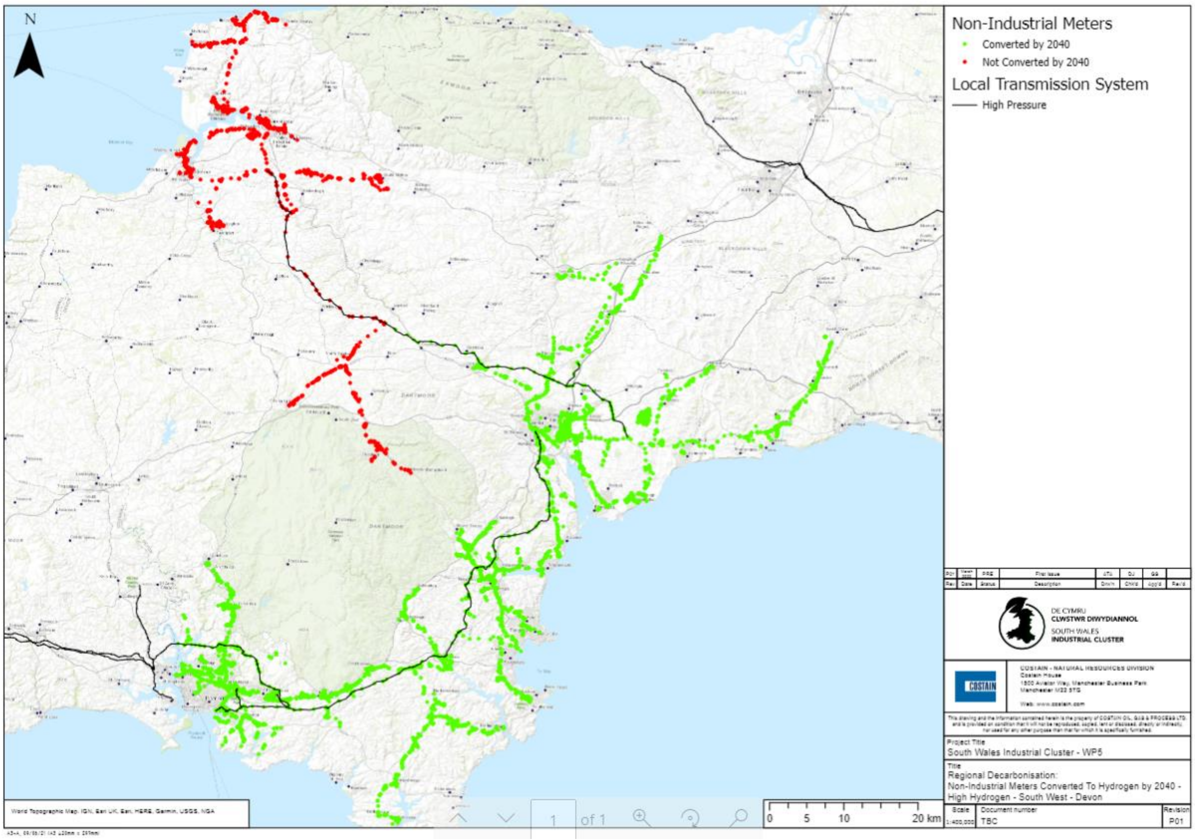


Figure 27.32. 2045 – 2050 High Hydrogen - Domestic and commercial Meters

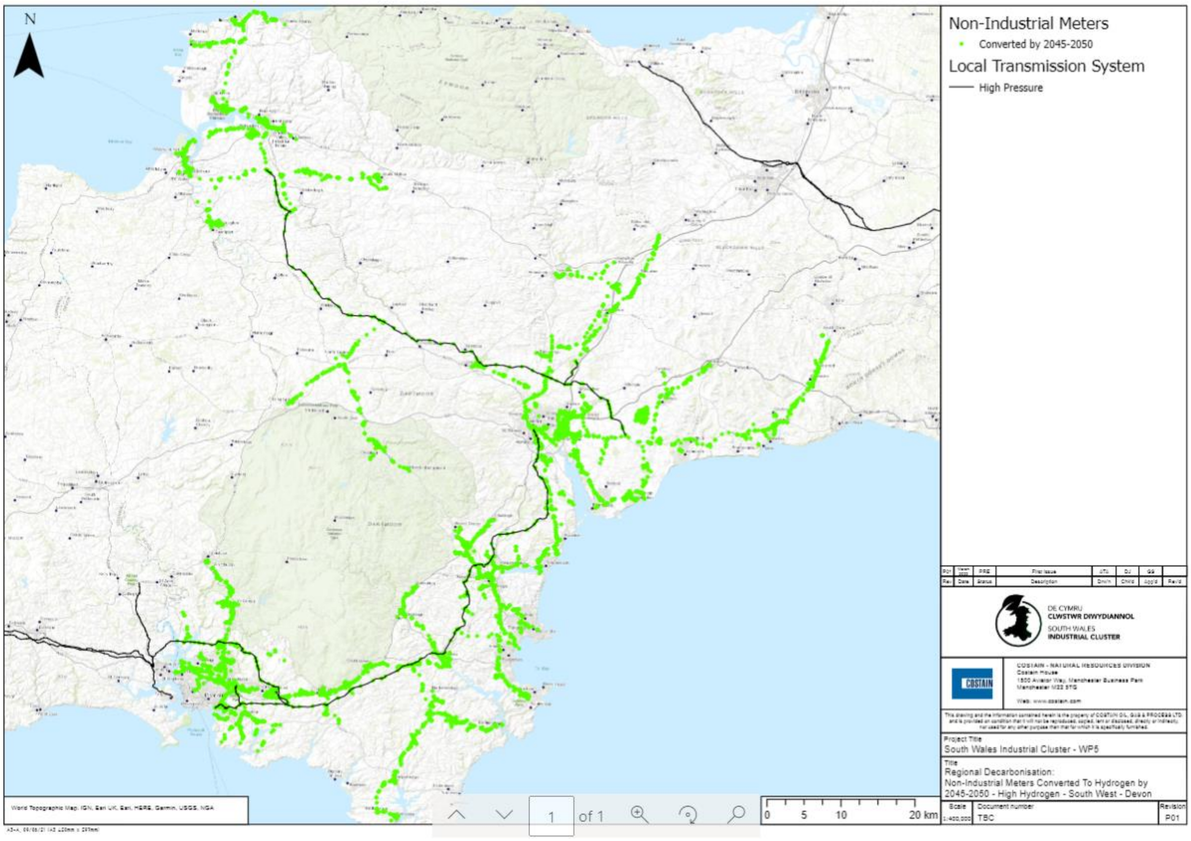
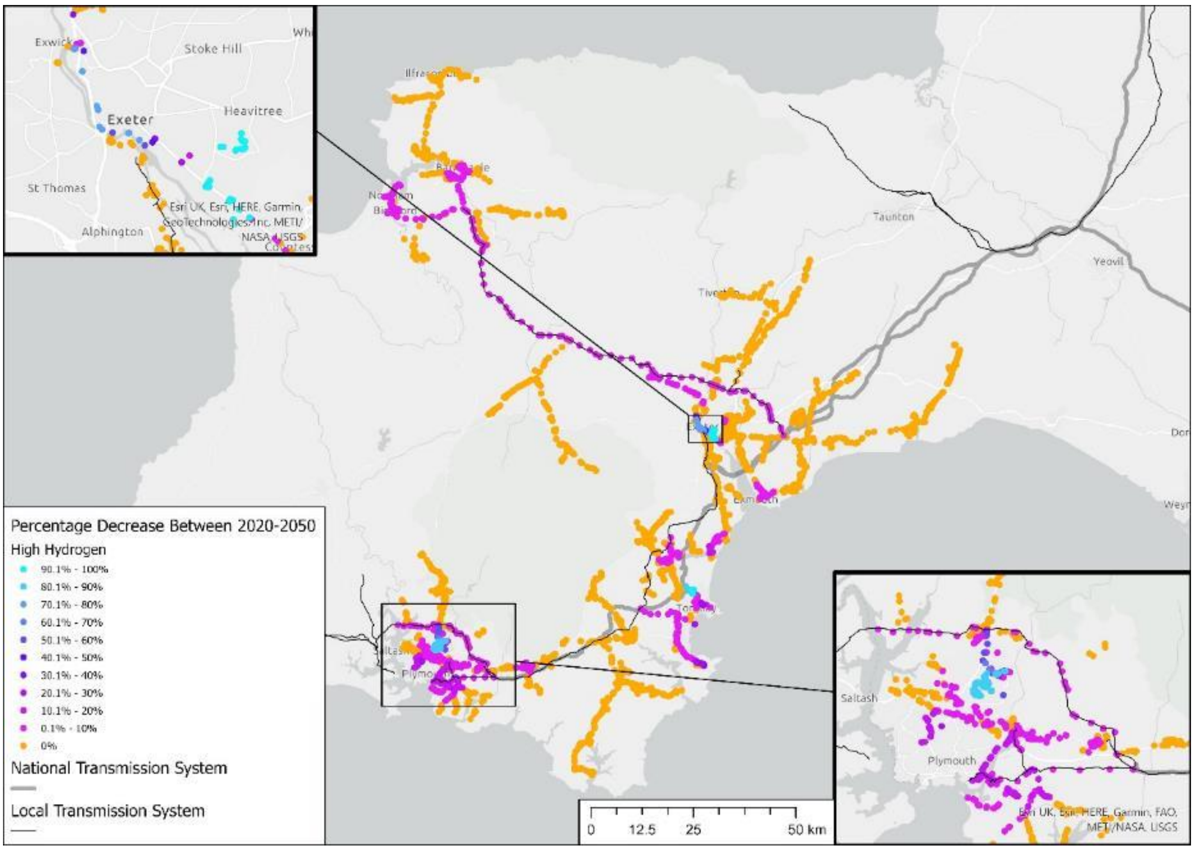


Figure 27.33. % Change in the Domestic and commercial Meters – High Hydrogen in 2050



27.3. CORNWALL

27.3.1. HIGH ELECTRIFICATION (ELE)

For the High Electrification WWU scenario modelled in ESME Hydrogen production starts around 2030 with maximum output being achieved by 2040 and then tailing away.

Table 27.13. South West Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

South West	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.0	0.0	0.3	7.0	19.1	15.2	11.5
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	0.0	1.9	14.5	9.4	8.4
Natural Gas Consumption from Distribution Network (TWh)	35.2	32.3	27.9	21.0	5.9	0.0	0.0

Figure 27.34. South West Distribution Network Use by Natural Gas and Hydrogen – High Electrification

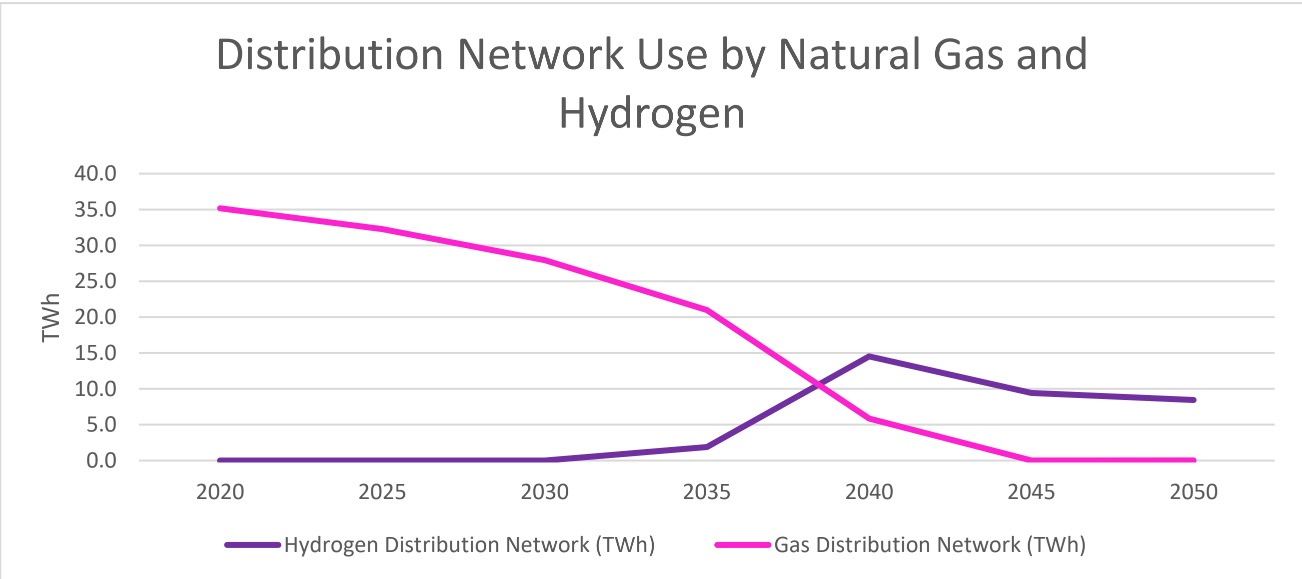


Table 27.14. South West Meters Converted per 5 Year Cycle – High Electrification

South West	Number of Meters Converted per 5 Year Cycle – High Electrification						
	2020	2025	2030	2035	2040	2045	2050
Choakford	0	0	0	0	151135	0	0
Meters Converting per Week (40 Wks/Year)	0	0	0	0	756	0	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

In 2040 the number of meters requiring conversion is higher than the recommended figure of 2500 from the HYDROGEN1 Project, therefore either an additional conversion team will be required, or a number of meters scheduled for 2040 would have to be push back into 2045.

Figure 27.35. 2020 – 2035 High Electrification - Domestic and commercial Meters

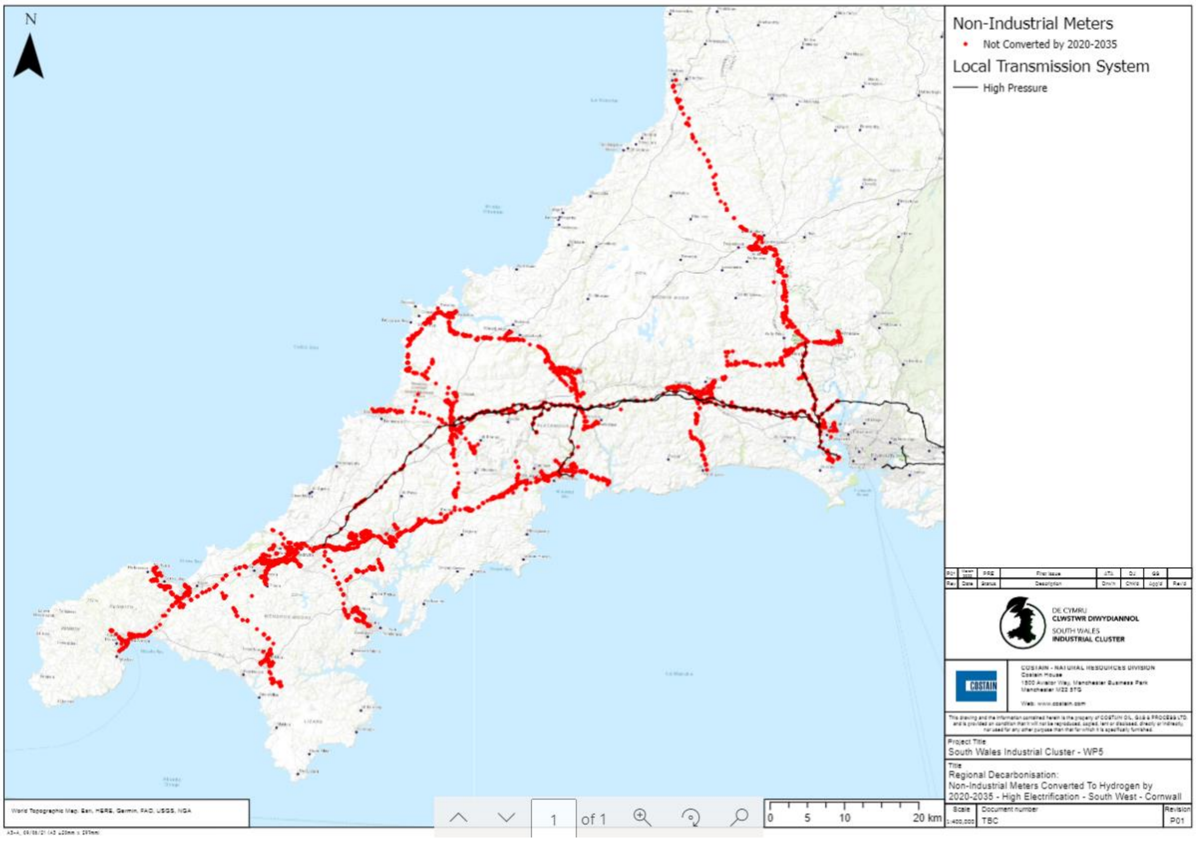


Figure 27.36. 2040 – 2050 High Electrification - Domestic and commercial Meters

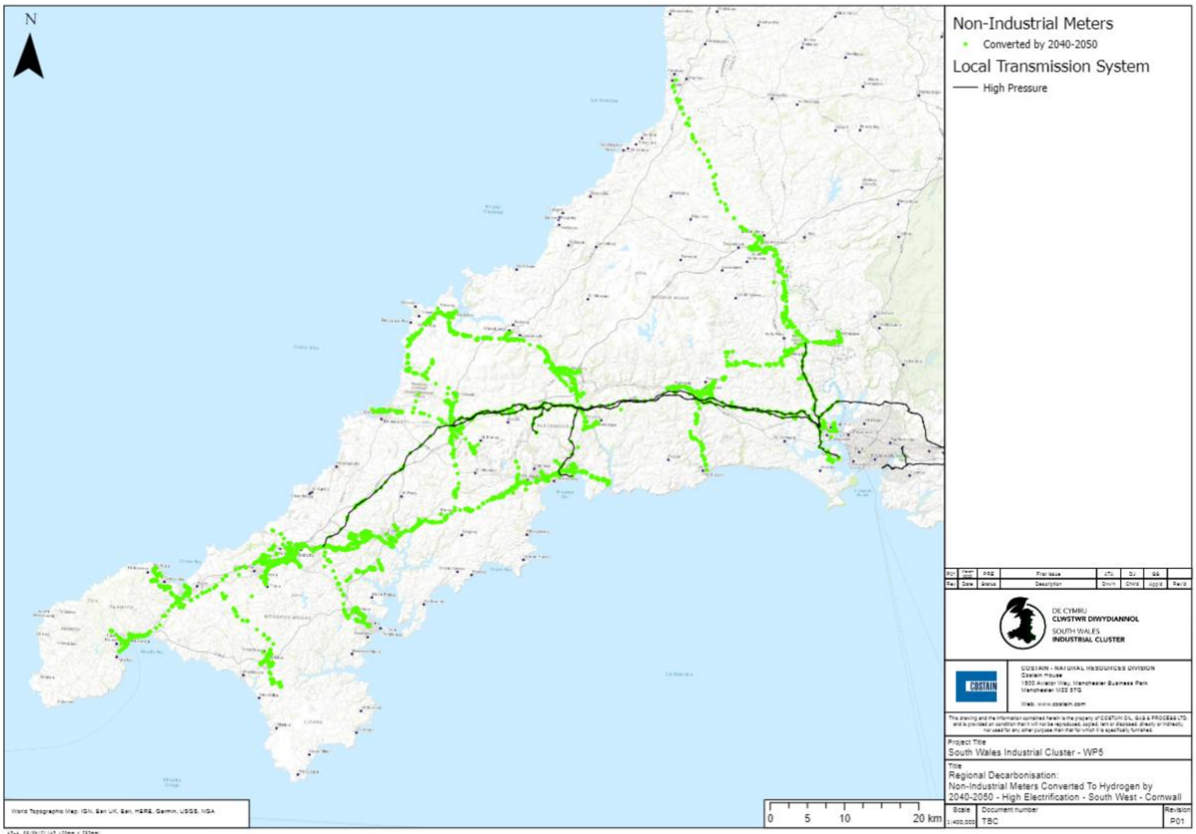
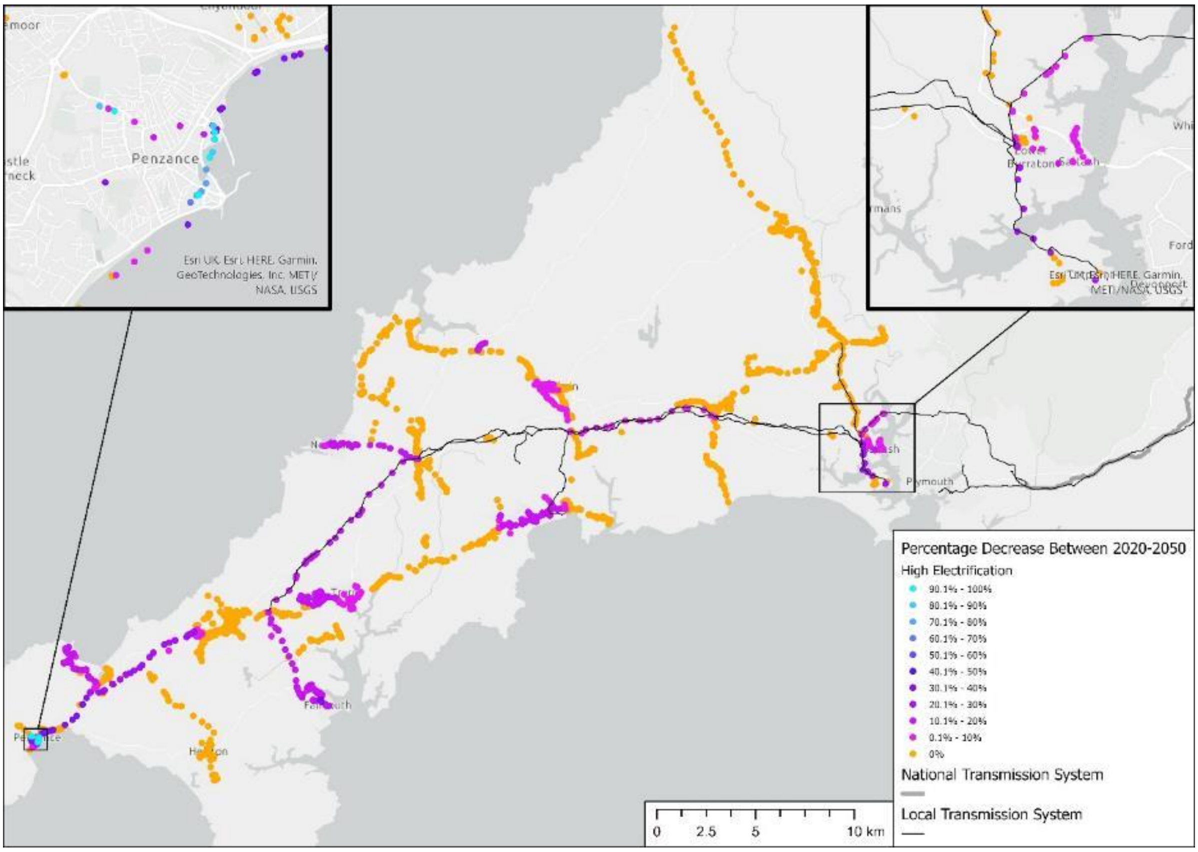


Figure 27.37. % Change in the Domestic and commercial Meters – High Electrification in 2050



27.3.2. BALANCED (BAL)

According to the WWU scenario modelled in ESME Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 27.15. South West Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

South West	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.0	0.0	4.7	14.3	15.0	13.9	13.9
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	3.2	9.8	23.3	24.6	18.8
Natural Gas Consumption from Distribution Network (TWh)	33.4	34.1	22.8	20.1	4.0	0.0	0.0

Figure 27.38. South West Distribution Network Use by Natural Gas and Hydrogen – Balanced

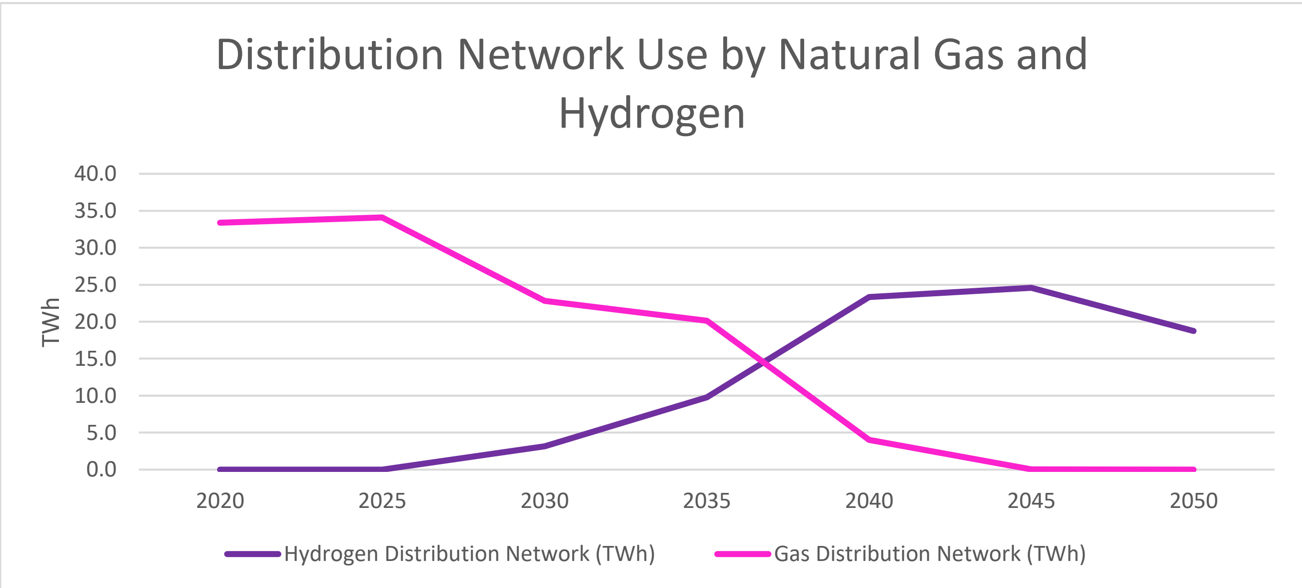


Table 27.16. South West Meters Converted per 5 Year Cycle – Balanced

South West	Number of Meters Converted per 5 Year Cycle – Balanced						
	2020	2025	2030	2035	2040	2045	2050
Choakford	0	0	0	0	156148	0	0
Meters Converting per Week (40 Wks/Year)	0	0	0	0	781	0	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

Figure 27.39. 2020 – 2035 Balanced - Domestic and commercial Meters

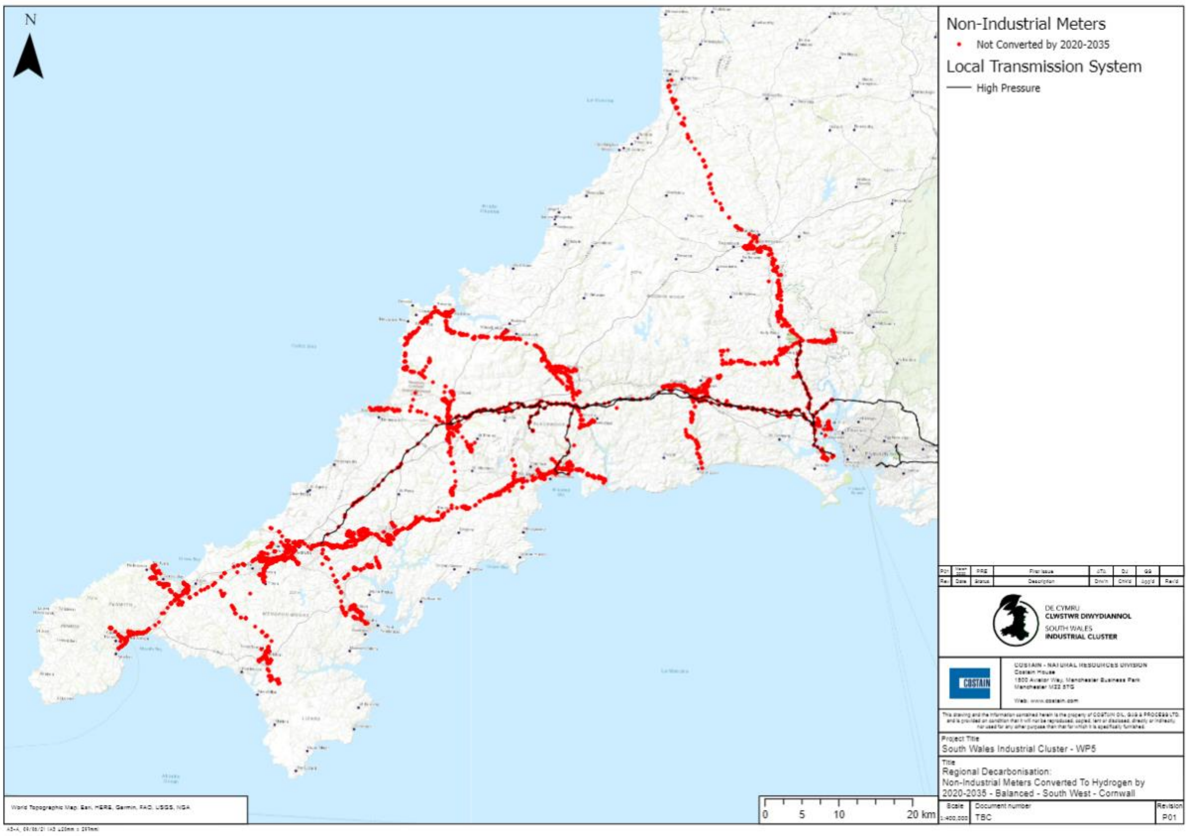


Figure 27.40. 2040 – 2050 Balanced - Domestic and commercial Meters

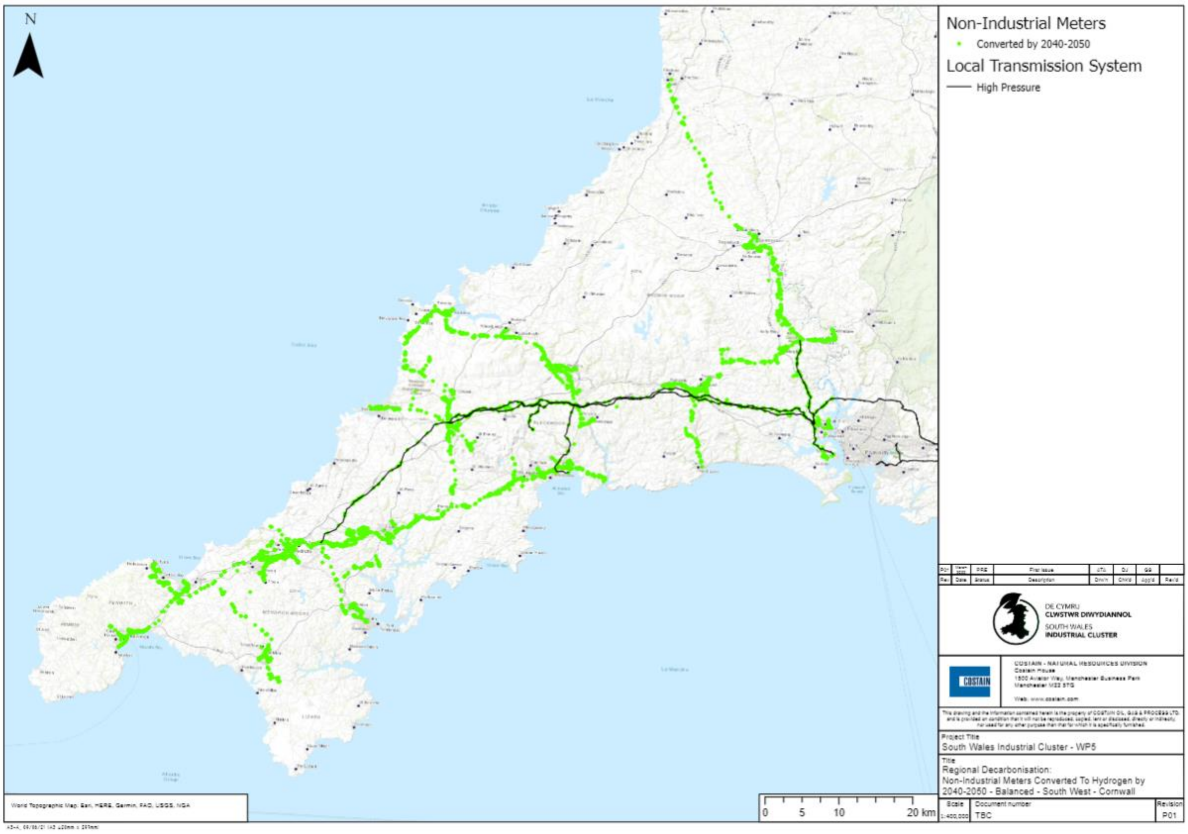
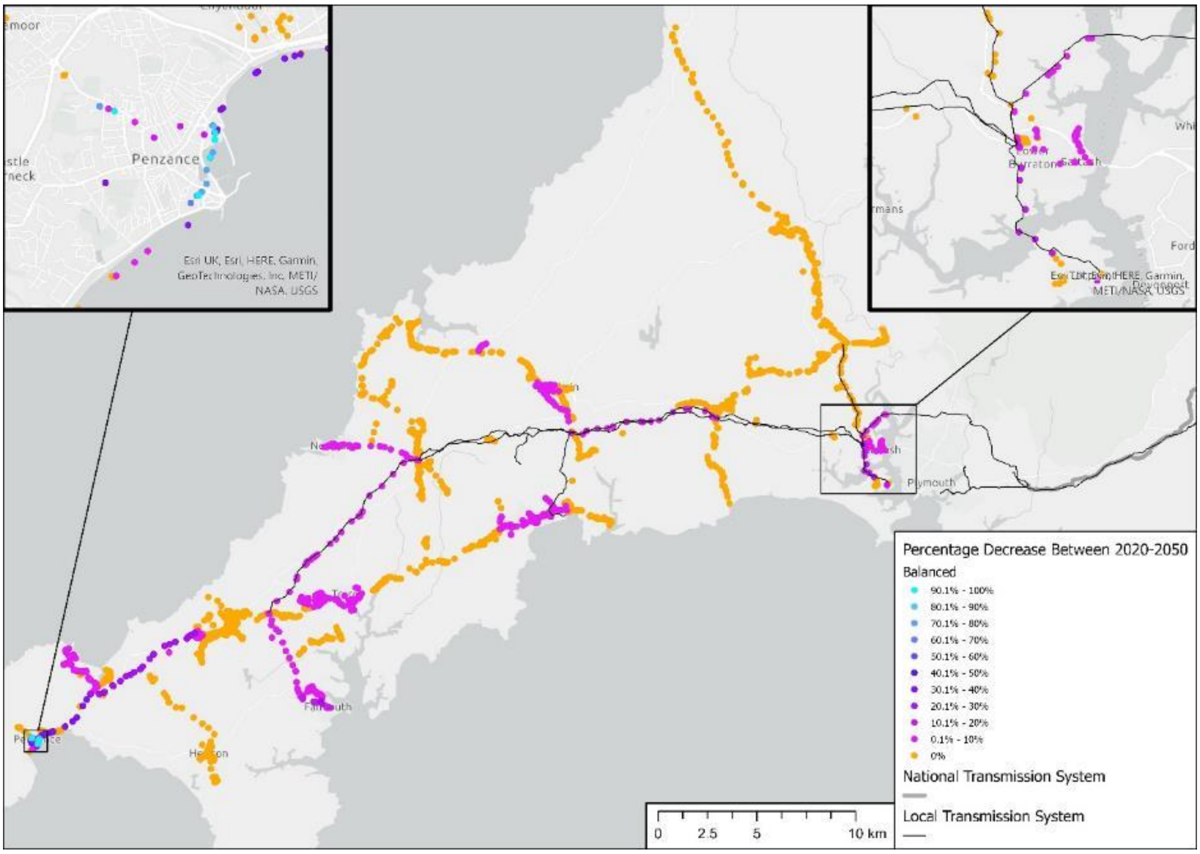


Figure 27.41. % Change in the Domestic and commercial Meters – Balanced in 2050



27.3.3. HIGH HYDROGEN (HYD)

According to the WWU scenario modelled in ESME Hydrogen production starts to ramp up after 2025 with maximum output being achieved by 2040 and then tailing away.

Table 27.17. South West Hydrogen Production and Distribution Network Natural Gas and Hydrogen Consumption

South West	2020	2025	2030	2035	2040	2045	2050
Total Hydrogen Production (TWh)	0.2	0.2	4.3	15.3	17.4	15.8	15.9
Hydrogen Consumption from Distribution Network (TWh)	0.0	0.0	4.2	11.4	24.0	24.9	21.7
Natural Gas Consumption from Distribution Network (TWh)	34.8	36.5	24.3	19.8	4.4	0.0	0.0

Figure 27.42. South West Distribution Network Use by Natural Gas and Hydrogen – High Hydrogen

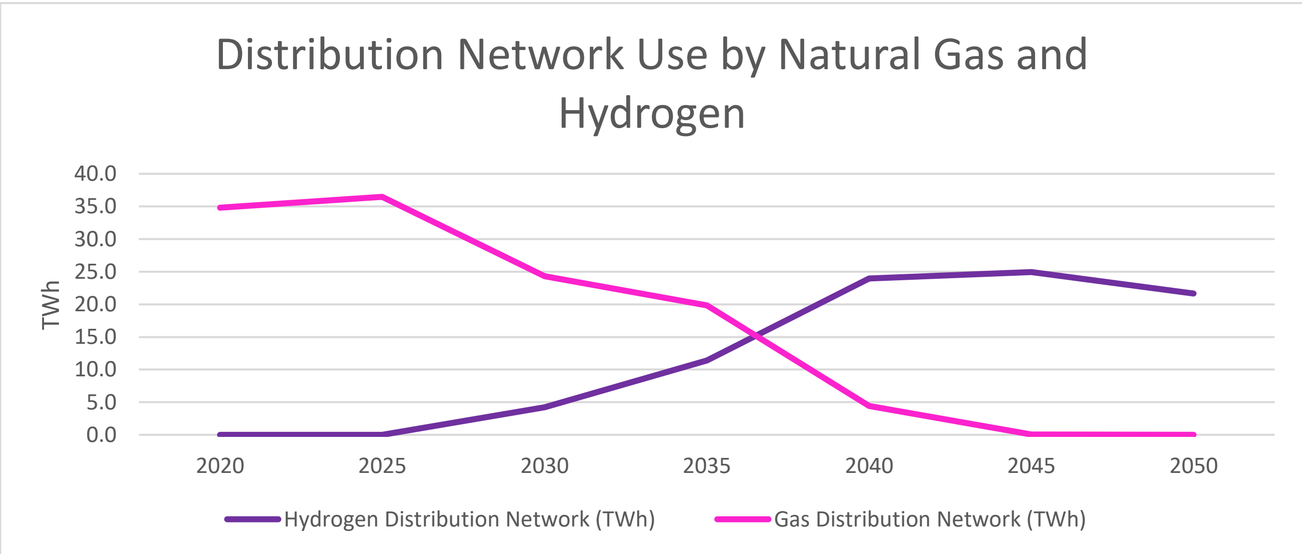


Table 27.18. South West Meters Converted per 5 Year Cycle – High Hydrogen

South West	Number of Meters Converted per 5 Year Cycle – High Hydrogen						
	2020	2025	2030	2035	2040	2045	2050
Choakford	0	0	0	0	156148	0	0
Meters Converting per Week (40 Wks/Year)	0	0	0	0	781	0	0

It should be noted the number of meters requiring conversion each week is based on the following:

- The meters' requiring conversion is a pro rata of the Hydrogen Distribution Network Consumption,
- The conversion process is assumed to take place outside the peak winter demand supply period ie over 40 weeks per year (March to November).

Figure 27.43. 2020 – 2035 High Hydrogen - Domestic and commercial Meters

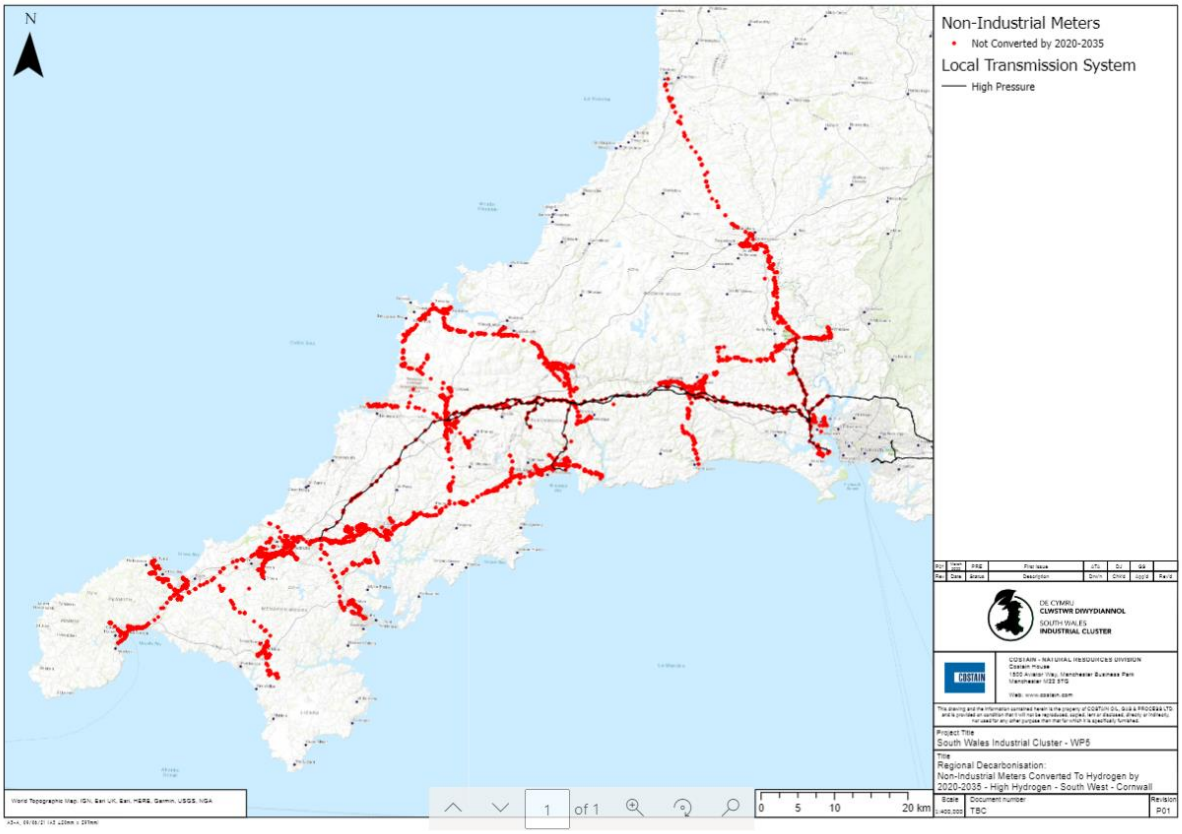


Figure 27.44. 2040 – 2050 High Hydrogen - Domestic and commercial Meters

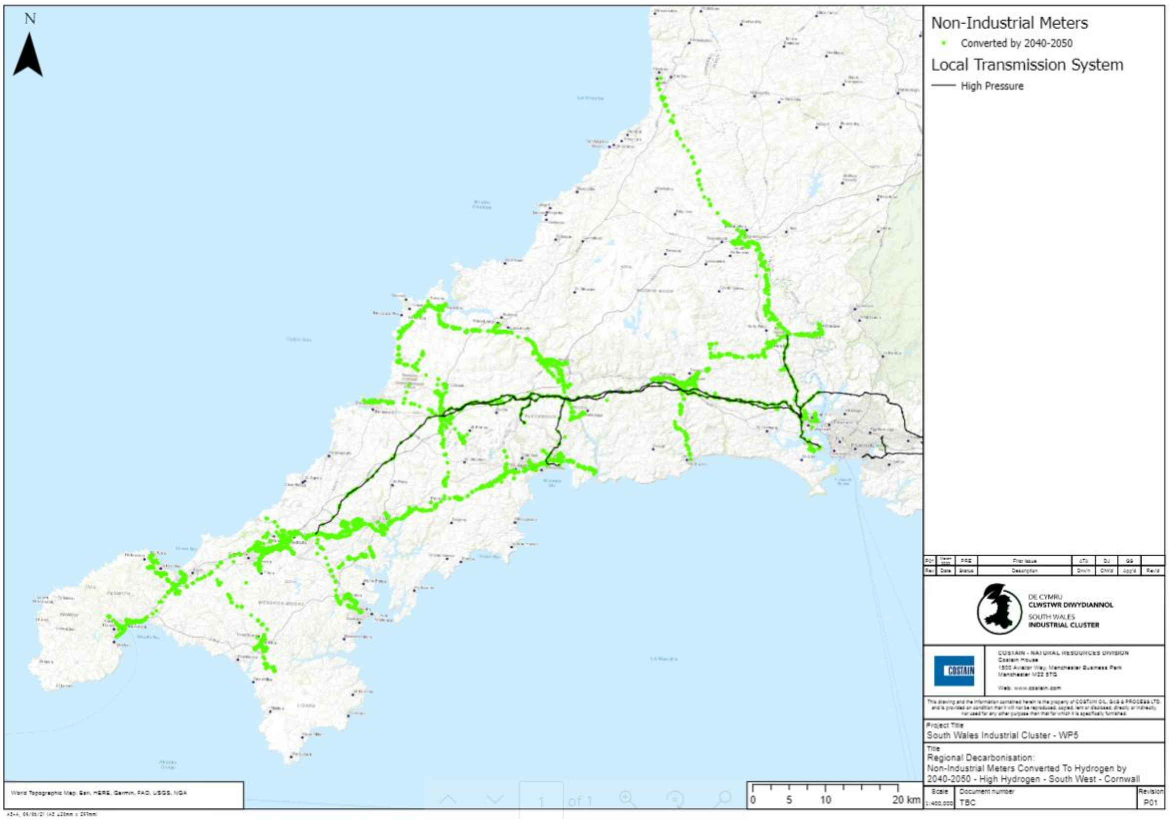


Figure 27.45. % Change in the Domestic and commercial Meters – High Hydrogen in 2050