Whole Energy System Analysis: Long Term Impacts on the Orkney Energy System

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Project Introduction and Analysis Objectives

The Integrating Tidal energy into the European Grid (ITEG) project aims to develop and demonstrate a state-of-the-art energy solution combining a tidal stream turbine with an electrolyser. This report is one of a series of reports from the project. It provides an overview of the work in Activity LT.4 'Whole System Impact and Analysis', carried out by Energy Systems Catapult (ESC).

This activity aims to determine the impacts of these ITEG technologies on the whole energy system (at local, regional, national and North West Europe levels), and to assess the techno-economic conditions for their successful wider deployment.

The first stage of this activity was the creation of a whole-system model of the Orkney Islands energy system, including supply and demand across all energy vectors. This model, Deliverable LT.4.1, was completed in 2019. The second stage of this activity (between 2019 and 2022) is the use of that model, along with other tools, to carry out the whole system analysis, which is the subject of this report, Deliverable LT.4.2.

The Orkney energy system has a number of particular distinguishing features, including considerable tidal and other renewable resources, severe electricity network constraints, and does not have any form of gas network meaning there is considerable use of heating oil.

The ITEG project's combined tidal energy with electrolysis solution has the potential to overcome the electricity network constraints and enable much greater deployment of renewable energy generation, in turn providing numerous benefits to the community. This solution can also be deployed to other island and coastal communities throughout North West Europe.

The modelling and analysis carried out throughout this project explores and tests these potential benefits, using a number of system scenarios, and explores other potential impacts which the ITEG solution may have on the wider energy system and associated options.

This analysis is conducted firstly for the specific Orkney energy system. Then, later in the project, further analysis using complementary tools and methodologies assesses the potential wider roll-out in suitable locations across North West Europe, and the associated conditions required for suitable commercial roll out and deployment in different systems; These latter aspects are reported in Deliverable LT.2.3.

Methodology

To analyse the Orkney energy system, the ESC's EnergyPath Networks^{TM} modelling framework has been used. This is a whole energy system optimisation framework which establishes cost effective future pathways for local energy systems across all energy vectors.

The Orkney energy system was first modelled in substantial detail, complete with options for deployment of the ITEG technologies – both in the near term and enabling widespread roll-out of tidal generation, electrolysis and hydrogen use in the longer term. Attention was given to the particular details of the energy generation options, Orcadian network representations, and to the local domestic and non-domestic building stock, with specific energy demand profiles of each type of building and usage.

The modelling framework is well established, and the details of the Orkney energy system model were validated before analysis.

A number of scenarios were developed, starting from a baseline system without the ITEG technologies available, then modelling the ITEG project deployment of a single unit (i.e. one-off tidal turbine with electrolyser), and progressively enabling deployment of the ITEG solution and complementary technologies at greater scale across Orkney. These scenarios also enabled comparison of high-hydrogen systems with high electrification systems, and testing of sensitivities to various prices. Some introduction of electric vehicles has been assumed in the modelling alongside the increase in electricity demands that these bring. Later scenarios also included a costed option to decarbonise ferries by switching from oil to hydrogen. Decarbonisation of other transport modes such as HGVs, buses and the maritime fleet (beyond ferries) was not included in the modelling.

<u>Conclusions</u>

There is potential for the combination of tidal generation and electrolysis technologies, and the electricity and hydrogen they can produce, to play a role in the decarbonisation of the Orkney energy system in the following ways:

- System carbon emissions can be reduced by deploying tidal generation and electrolysis (rolled-out after the ITEG project), and particularly with increased hydrogen use.
- Heating of domestic and non-domestic buildings can shift from predominantly oil and some electric resistive heating today, to predominantly heat pumps (ground source and air source) with a mix of other electric and hydrogen heating by 2050 (with the detail varying by scenario and by location).
- For non-domestic buildings, hydrogen can be important to decarbonise uses that are hard to switch to electric heat, such as some industrial processes.
- Primary energy has the potential to be a mixture of wind and tidal generation alongside some solar PV, with the potential to export electricity from Orkney.
- Hydrogen could be used – in varying proportions – in fuel cells, non-domestic buildings and domestic buildings, as well as for maritime purposes, and could potentially be exported if market prices were high enough for Orkney-produced hydrogen to compete.

It was also found that extensive electrification of heat allows greater consumption of renewable generation, which can release network headroom, as local electricity use is increased and electricity exports are reduced. In some cases this headroom is then available to allow siting of electrolysers in different locations to tidal generation (such as closer to locations of hydrogen demand). Deployment of additional supporting technologies such as heat pumps and electric vehicles will be crucial for the overall system to achieve decarbonisation.

… (continued overleaf) …

By exploring different options for hydrogen within the Orkney energy system our modelling has shown:

1. Deployment of the single turbine and electrolyser unit within the ITEG project leads to a small reduction in imported electricity (by approx. 300MWh/year, or 1%, in 2050) and a more significant increase in exported electricity (by approx. 3.1GWh/year, or 20%, in 2050). The hydrogen produced is used mainly in commercial and industrial buildings.
2. With ITEG technologies further built as co-located 'packages', each comprising 20MW of tidal generation with 5MW of electrolysis capacity (electrical power), a total of five packages were deployed across Orkney with a total of 100MW of tidal generation and 25MW of electrolysis. This deployment enables additional hydrogen production and further decarbonisation of industrial and commercial buildings, eliminating nearly all residual emissions in the model by 2050. When introduced at this scale, hydrogen allows a reduction in emissions in 2050 to a residual level of around 550 tCO_2 per year (which comprises emissions from use of peat in distilleries and a small residual carbon load in electricity imported from the UK mainland, which did not have options for abatement available within the modelling).
3. With this 100MW level of tidal generation, an additional 174GWh per year of renewable electricity is exported from Orkney by 2050. In order to enable this level of deployment and export, increased electricity network capacity is required between Rousay and Westray. There is also a need to build some hydrogen pipelines to move hydrogen from production locations to demand locations.
4. If ITEG technologies can be deployed separately, rather than as combined packages, then three of the electrolysers are optimally sited at different locations to tidal generation assets. Within the model, transport of electricity is found to be more cost effective than transport of hydrogen – partly as the need to build hydrogen pipelines is avoided. There is an 80% increase in consumption of electricity from current levels in domestic buildings as they are converted to electric forms of heating. This provides additional local demand for the electricity generated from renewables, freeing up capacity on the island ring.
5. Tidal generation can make a valuable contribution to the Orkney energy system even in the absence of electrolysis. This is primarily due to the highly predictable nature of tidal generation compared to other types of renewable generation and the increased diversification of the generation mix it provides which has additional value to the energy system compared to installing only one technology.
6. Without hydrogen being available (either produced through local electrolysis or imported) the lowest levels of emissions cannot be achieved with the modelling assumptions made. Hydrogen provides a low carbon solution for buildings that are hard to electrify, either because of their form and activity, or as a result of local network constraints.
7. The influence of access from Orkney to a hydrogen export market changes depending on the market price assumed. Below a threshold level of £150/MWh[1] (approx. £5/kg H_2) the optimised system deploys around 95MW of tidal capacity and 40MW of electrolyser capacity,

[1] When considering the likelihood of certain market price levels, it is important that prices are compared on a like-for-like basis. In the modelling and analysis all energy prices were at the Orkney energy system boundary. Import costs quoted here therefore include shipping to Orkney (whereas figures in literature are often quoted as ex-plant prices only). For the same reason, export prices in this modelling do not include cost of shipping to customers. No attempt has been made to estimate what these shipping costs might be as part of this work. Although many people have suggested that future market prices may be well below this threshold, opinion is divided on how achievable such figures really are, and this work presents the analysis findings without attempting to second-guess actual future market rates.

with little change to the Orkney energy system resulting from gaining access to a hydrogen export market. If market prices are above this level, and the UK mainland electricity connector is not built, then significant additional deployment of both tidal generation and electrolysers may be enabled, with increases of 500MW tidal and 200MW electrolysis achieved in the modelling. If the mainland connector is built then, at a hydrogen market price of £150/MWh (approx. £5/kg H_2), renewable generation is more likely to be exported directly as electricity rather than converted to hydrogen for export.

8. The optimal way to produce hydrogen for export is to locate both tidal generation and electrolysers close to the export point, to limit the costs associated with reinforcing the electricity networks and building hydrogen networks. This suggests tidal installation in the Pentland Firth with electrolysers on Hoy or Flotta (assuming this is the export terminal). Any hydrogen required locally could then be shipped to elsewhere on Orkney from this central production hub.
9. If significant volumes of hydrogen are to be exported then it is likely that some hydrogen pipelines will need to be installed between the point of production and the export terminal. Alternatively, additional electricity network capacity might be required such that electrolysis can be located at the export point.
10. Introducing an option to also import hydrogen can change the choices made to reach net zero. Cheap hydrogen available for import at £75/MWh (approx. £2.50/kg H_2) or less leads to more use of hydrogen overall but with very little local production, whilst prices above £100/MWh (approx. £3.30/kg H_2) lead to higher levels of local hydrogen production, although this is still less than if there is no option to import hydrogen. The level of tidal generation capacity required seems to be reasonably insensitive to whether hydrogen can be imported, regardless of price, with around 95MW of tidal generation when the hydrogen price is below the threshold required for significant export.
11. Building the proposed 220MW interconnector to the UK mainland enables additional renewable generation which is a mixture of both tidal and wind generation (400MW of tidal and 140MW of wind are added when the hydrogen price is at or below the threshold level of £150/MWh (approx. £5/kg H_2) at which large scale export is promoted when the mainland link is not available). The increased diversification of the generation mix has additional value to the energy system compared to installing only one technology. This additional renewable generation also creates opportunities for increased electrolysis with an additional 200MW deployed (when the hydrogen price is at or below £150/MWh) producing a total of 280GWh of hydrogen per year.
12. Building the electricity interconnector upgrade unlocks significant potential for the Orkney energy system, allowing:
    - a significant increase in cost-effective wind and tidal generation to a level that makes Orkney almost self-sufficient in a decarbonised future, only needing to import energy on limited occasions through the year;
    - export of significant quantities of both wind and tidal generation with possibilities for hydrogen export if markets can be accessed at a competitive price; and
    - opportunities to maximise the benefits of renewable generation through hydrogen production when generation is in excess of the combination of local demand and the capacity of the new interconnector.

13. Investment in the electricity interconnector upgrade, regardless of other factors, would therefore be a “no-regrets” decision which could be implemented immediately without pre-conditions, and there is a clear case for change in the present regulatory constraints.
14. Even with the new interconnector, the cost-optimal level of renewable generation deployment results in some curtailment at times of peak generation. The cumulative cost of all the changes throughout the entire energy system (from generation through to end use across all vectors) which would be required to avoid curtailment completely is greater than the value of avoiding a small amount of curtailment.

Interpretation

Finally, the following points should be noted in respect of limitations and interpretation of the work:

- The modelling carried out is based on a whole-energy-system cost optimisation tool. However, energy systems do not act solely in a whole system, cost optimal manner. In practice, individual actors in the system take decisions to suit their own needs, and policy and regulation may enable or block desired innovation. In the Orkney context this could apply to both the hydrogen and electric parts of the system.
- For example, expenditure on network upgrades will only be allowed by Ofgem under certain circumstances and can be hard to get approved ahead of demand.
- This may increase the attractiveness of hydrogen options as, even if they are higher cost, they may be easier to deploy than getting approval for significant electricity network capacity investment. Alternatively, some assumptions around the future hydrogen system may not be valid under current regulations (for example, the safety case for hydrogen storage trailers to share a ferry with other passengers).
- Subsequent stages of this work therefore explored these issues and show how the role of the ITEG technologies may be influenced by social and regulatory factors.

- Alongside this Deliverable LT.4.2 “Whole Energy System Analysis: Long Term Impacts on the Orkney Energy System”, the following related reports provide further information:
    - Deliverable LT.4.5 Summary of Findings from the whole energy system studies carried out under the ITEG project
    - Deliverable LT.4.3 Hydrogen Handling and Logistics: Challenges and Opportunities in a Remote Archipelago
    - Deliverable LT.2.3 Opportunities for Roll-Out of Tidal Generation with Electrolysis Across North West Europe
    - Deliverable LT.4.4 Energy Management System Analysis
    - Deliverable LT.2.2 Social Acceptance Study
    - Deliverable LT.1.1 Roadmap Study for Tidal Generation with Electrolysis
    - Deliverable LT.1.2 Business Case for Tidal Generation with Electrolysis

1 Introduction

1.1 Whole Energy System Analysis within the ITEG Project

1.1.1 Project Context

The Integrating Tidal energy into the European Grid (ITEG) Project aims to develop and demonstrate a state-of-the-art energy solution combining a tidal stream turbine with an electrolyser. This aims to overcome technical and commercial challenges associated with the use of abundant renewable energy resources in regions with weak or constrained electricity grids – a combination which is characteristic of island communities – and to use hydrogen to capture this green energy and enable decarbonisation of the wider energy system and the many domestic and commercial users of energy.

The integrated solution was intended to combine Orbital's next generation 2MW floating tidal energy converter, the Orbital O2 2MW (Figure 1), with a custom built 500kW Elogen electrolyser[2] (Figure 2) and an onshore energy management system (EMS) to be deployed at the European Marine Energy Centre (EMEC)'s hydrogen production site on the Orkney island of Eday.

Figure 1 – Orbital O2 tidal energy converter (courtesy Orbital Marine Power)

[2] Note that the project objectives were modified, at a relatively late stage during the project, to reflect the supply challenges suffered by Elogen. These resulted in a number of strategic changes at the Caldale, Fall of Warness site specifically, namely (a) not installing the intended Elogen electrolyser; (b) making use instead of a pre-existing electrolyser on site which was modified and used to demonstrate the concept of the tidal generation and electrolysis technology combination, EMS control, etc; and (c) including a new flow-cell battery on site. The analysis in this report (conducted prior to some of these changes) includes use of the originally-intended electrolyser rating at Caldale, as well as use of the pre-existing unit alongside it, and of the flow-cell battery. Much of the analysis is concerned with roll-out at greater scale across the archipelago, which is not materially affected by these changes. The findings therefore remain valid, and this report has not otherwise been amended to reflect the on-site changes.

Figure 2 – Elogen electrolyser (courtesy Elogen)

1.1.2 Long Term Impacts Work Package

The development, deployment and demonstration of these technologies is carried out within the ITEG project 'Investment' and 'Implementation' work packages.

In parallel with this, the ITEG project **'Long Term Impacts' work package (WP LT)** aims:

- to assess in detail the impact and potential benefits of the ITEG solution on the whole energy system, and how it might be rolled out across a range of different energy systems,
- to develop a roadmap and business case, to support the prioritisation of further development as part of a commercially viable marine energy solution,
- to understand the social acceptance aspects associated with the specific technologies, and
- to identify future project opportunities, investors, networks and partners.

Having identified and quantified the potential beneficial impact of the solution in various scenarios, the Long Term Impacts WP then aims to ensure that the benefits can actually be realised.

Within WP LT, these aims are addressed by four parallel activities.

1.1.3 Whole Energy System Analysis

This specific report relates to **Activity LT.4 'Whole System Impact and Analysis'**, which is carried out by Energy Systems Catapult (**ESC**).

In summary, this activity aims:

- to determine the impact of deploying a combination of tidal generation and electrolysis on the whole energy system (at local, regional, national and North West Europe levels), and
- to assess the techno-economic conditions for successful solution deployment.

The four activities within WP LT are closely interdependent, and this modelling will also be used to inform the other activities, to enable a coherent set of outputs from the project and to maximise the beneficial impact beyond the end of the project.

The first stage of this activity was the creation of a whole-system energy model of the Orkney Islands energy system, including supply and demand across all energy vectors. This model, Deliverable LT.4.1, was completed in 2019.

The second stage of this activity is the use of that model, along with other tools, to carry out the whole system analysis, which is the subject of this report, Deliverable LT.4.2. The vast majority of the analysis was carried out between 2019 and 2021, with iterative updates throughout that time and some further work in 2022. The final version of this report was published towards the end of the project in 2023.

1.2 The Current Orkney Energy System

The Orkney archipelago is located approximately 10 km (6 miles) north of the Scottish (UK) mainland across the Pentland Firth. It comprises about 70 islands, of which 20 are inhabited. The population numbers some 22,000.

The largest island – Mainland – with an area of 523 square kilometres (202 square miles), is often referred to as "the Mainland". In this report, in order to distinguish it from the UK mainland (both of which are mentioned frequently), it is referred to as "Orkney Mainland". Three quarters of the population live on this island.

Figure 3 – The Orkney archipelago

The Orkney energy system stands out compared to a typical UK or even Scottish system. Some of the key distinguishing features include:

- A large level of local, low carbon electricity generation – by 2013 on an annual basis Orkney was already generating more electricity than its total demand[3].

[3] https://www.oref.co.uk/wp-content/uploads/2015/05/Orkney-wide-energy-audit-2014-Executive-Summary.pdf

- Despite the existing high levels of generation, there are considerable untapped low carbon energy resources, with more potential for wind, tidal and wave generation, spread across the archipelago.
- Severe network constraints both between the islands and to the UK mainland. These are mitigated by an Active Network Management (ANM) system that actively curtails generation to keep within network limits. This blocks the as-yet untapped renewable resource from being used, as any new generation is likely to suffer such high levels of curtailment as to make it uneconomic. The ANM zones are shown in Figure 4.

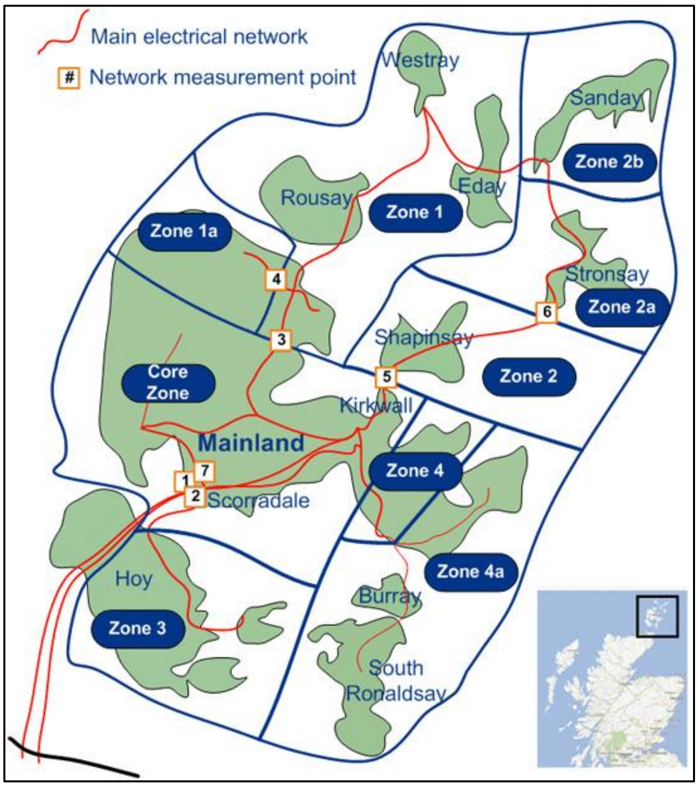

Figure 4 – SSEN diagram of the current ANM system[4]

- There has been a push to reinforce the electricity grid connection to the UK mainland, to unlock the potential for more low carbon generation exporting to the national grid. In 2019 Ofgem approved an upgrade of the grid link capacity to 220MW, but only if there was an additional 135MW of generation approved by December 2021[5].
- Historically and into the present-day, Orkney has been at the forefront of energy innovation, with numerous projects testing new approaches and a highly engaged local community. Orkney was the site of the first grid connected wind turbine in the UK[6], and now with organisations like the European Marine Energy Centre[7] it is at the forefront of

[4] https://www.ssen.co.uk/anm/orkney/status/

[5] https://www.ofgem.gov.uk/system/files/docs/2019/09/conditional_decision_on_orkney_final_needs_case_2.pdf

[6] At Costa Head, in 1951. http://www.oref.co.uk/orkneys-energy/history/

[7] http://www.emec.org.uk/

testing new tidal technologies and hydrogen systems, with its own hydrogen strategy and over £50 million of ongoing hydrogen innovation projects[8].

- Other features such as the absence of a gas network and the characteristics of the local building stock, that make it unusual in a UK context but can be found on other Scottish islands.

Despite the provision of low carbon electricity generation, Orkney still has a high level of carbon emission per capita, 12.4t/capita in 2019, compared to a Scottish average of 5.7t/capita (5.2t/capita across the UK)[9]. Where energy end use is not electrified it is provided in a high carbon way, for example homes with oil heating; there is no gas grid on Orkney. Scotland has a target to reach net zero carbon by 2045[10] and in 2019 Orkney demonstrated its commitment to achieve this as a local area by declaring a climate emergency[11].

Aside from the climate challenges, Orkney also has one of the highest rates of fuel poverty in the UK, with studies suggesting that over 60% of Orkney households are in fuel poverty[12]. This brings a significant challenge to the Orkney energy system and the lives of Orkney residents. Actions that could reduce energy costs for local residents could have a very significant positive impact on the area.

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[8] https://www.orkney.gov.uk/Files/Strategic_Projects/Hydrogen%20projects/Hydrogen%20strategy.pdf

[9] See https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/996057/2005-19_UK_local_and_regional_CO2_emissions.xlsx

[10] https://www.gov.scot/policies/climate-change/#:~:text=Scotland's%20world%2Dleading%20climate%20change,%2C%20definitively%2C%20within%20one%20generation.

[11] https://www.orkney.gov.uk/OIC-News/Council-declares-climate-emergency.htm

[12] https://www.orkney.gov.uk/Files/Consultations/Fuel-Poverty/Draft-Orkney-Fuel-Poverty-Strategy-2017-2022.pdf

1.3 Modelling of Potential Benefits and Impacts

The ITEG project's combined tidal energy with electrolysis solution has the potential:

- to enable much greater deployment of renewable energy generation (both tidal and other complementary resources such as wind generation),
- to overcome electricity grid constraints where networks are weak, unreliable or of limited capacity,
- to substantially reduce, or even avoid, curtailment of generation at times of surplus production, and thus radically improve the business case for investment and deployment,
- to maximise use of zero-carbon natural resources, and avoid import of fossil fuels or fossil-fuel-derived (or other non-zero-carbon) electricity, and
- to provide reliable, local supplies of green hydrogen to enable decarbonisation of particular demands which are difficult to decarbonise, and to provide clean fuel for numerous applications including transport, heating, industrial processes, etc.

These benefits should be realisable not just in Orkney but in many other island and coastal settings with similar characteristics across the UK and throughout North West Europe.

The modelling and analysis throughout this project, as reported here, explores and tests these potential benefits, using a number of system scenarios.

It also explores other potential impacts which the ITEG solution may have on the wider energy system and associated options including energy networks, other energy production assets and energy demands. (For example: Does deployment of the ITEG solution alleviate or require electricity network reinforcement or curtailment of other generation assets? Does it lead to different choices to meet heat or transport demands?)

By using a number of system scenarios and sensitivities, the modelling has explored aspects such as:

- how introducing the ITEG solution might influence the local energy system,
- the scale of the opportunity for the ITEG solution on Orkney and the influence on that opportunity of access to a national hydrogen market,
- the relative costs and benefits of investing in electricity and hydrogen networks on Orkney,
- how decarbonisation of both transport and building energy demand on Orkney could influence energy choices and options.

This analysis has been conducted firstly for the specific Orkney energy system. Next steps undertaken included further analysis using complementary tools and methodologies to assess the potential wider roll-out in suitable locations across North West Europe, and the associated conditions required for suitable commercial roll out and deployment in different systems; these are reported separately.

2 Modelling and Analysis Methodology

2.1 Introduction to EnergyPath Networks^{TM}

To analyse the Orkney energy system, the ESC's EnergyPath Networks^{TM} (**EPN**) modelling framework has been used. This is a modelling tool previously developed by ESC as part of the Energy Technologies Institute's Smart Systems and Heat Programme[13].

To understand the modelling and analysis carried out, it is critical that readers understand the following fundamental points about the nature of the EPN framework and methodology:

- EPN is a **whole system optimisation** analysis framework that aims to find **cost effective future pathways** for local energy systems **to reach a carbon target** whilst meeting other local constraints.
- EPN is **spatially detailed**, covers the **whole energy system** and **all energy vectors**, and **projects change** over periods of time.

2.2 General EPN Approach

EnergyPath Networks is unique in combining several aspects of energy system planning in a single tool:

- Integration and trade-off between different methods of meeting heat demand – e.g. gas, solid/liquid fuels, electric power, hydrogen, district heating schemes, etc.
- Integration through the energy supply chain from installing, upgrading or decommissioning assets (production, conversion, distribution and storage) to upgrading building fabric and converting building heating systems.
- Inclusion of existing and new build domestic and commercial buildings.
- The spatial relationships between buildings and the networks that serve them, so that costs and benefits are correctly represented for the area being analysed.
- Spatial granularity down to building level when the input data is of appropriate quality.
- A modelled time frame of 2020 to 2050.

Taken together, the analyses can be used to ensure long-term resilience in near-term decisions, mitigating the risks of stranded assets.

Details of the EPN approach are summarised in Appendix B. A brief description of the general approach is set out below.

[13] https://es.catapult.org.uk/case-studies/smart-systems-and-heat/

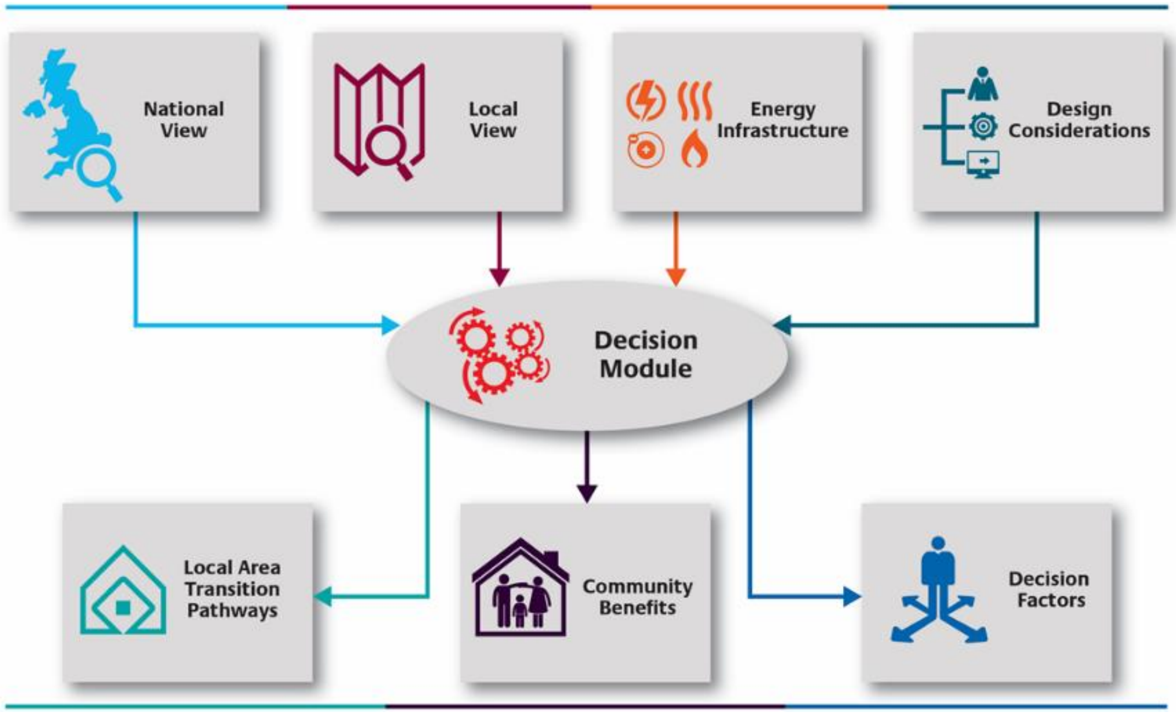

Figure 5 – Schematic of the EPN process

EPN uses optimisation techniques in a **Decision Module** to compare many combinations of options (tens of thousands) rather than relying on comparisons between a limited set of user-defined scenarios (although scenarios of different inputs are still typically used and the Decision Module then runs within each of these scenarios). The focus is decarbonisation of energy used at a local level. This enables informed, evidence-based decision-making.

Inputs

The inputs into the decision module include the **national view,** a perspective of the current and future energy system outside of the boundaries of the local area (i.e. out with Orkney). This is important to allow an understanding of issues such as the national grid decarbonisation, which is outside of the local area's control but will have significant impacts on the local energy system. In this project the national view is provided by ESC's Energy System Modelling Environment (ESME) tool[14].

The **local view** includes a detailed understanding of the geography of the local area, in particular the local building stock. A detailed picture of the local domestic and non-domestic buildings is produced, with information on size, fabric, heating system and activity. This input is spatially very detailed, with inputs at the individual building level (in many cases precise detail is not available at the individual building level and so statistical assumptions need to be made).

The **energy infrastructure** is represented to the decision module from data on the current energy networks, storage and generation. For this project it includes spatial electricity network data, showing locations and capacities of feeders and substations. It also includes information on current generation (e.g. the wind farms on Orkney). Additionally, it includes future cost curve

[14] https://es.catapult.org.uk/capabilities/modelling/national-energy-system-modelling/

projections for reinforcement of network infrastructure components to a range of future capacities.

Design considerations are expert knowledge as to the engineering challenges and possibilities for installing different technologies, for example limitations on different retrofit insulation based on existing building fabric, or limits on the deployment of Ground Source Heat Pumps based on likely access to suitable land for installation – both in terms of quantity but also in physical access for large machinery.

<u>Outputs</u>

Once these inputs have been fed into the decision module, the outputs include:

Local Area Transition Pathways, an understanding of what needs to happen, where and when within a local area in order to meet its local carbon target in the most cost effective, whole system way.

There is significant uncertainty in future energy systems, and so **decision factors** capture how the local area transition pathways may change under different future scenarios. Looking across a range of futures can provide guidance as to low regret ways forward that seem to make sense regardless of much uncertainty, whilst also identifying options that may only make sense under certain future conditions, and so illustrating the point at which a decision on that should be made.

Finally, **community benefits** recognises that, although not directly included in the optimisation model, there are wider impacts of transitions in the energy system, for example economic growth, air quality improvements and potential impacts on fuel poverty.

<u>Application with the ITEG Project</u>

In the ITEG project this overall EPN approach is used to understand how the technologies considered in the ITEG project would change the energy transition that Orkney has to undergo to meet its carbon ambitions. It explores the role that the ITEG technologies, tidal turbines and electrolysers, can play in making the Orkney energy transition lower cost and more effective. To do this it considers the future Orkney system if these technologies were not available, the future system with the technologies deployed as in the project (i.e. a one-off deployment), and, most importantly, future systems where these technologies are available at a greater scale across Orkney, looking at the long term impacts that the technologies developed and trialled in this project could have on the whole energy system. (Later in the project, wider roll-out across the UK and North West Europe will be considered, using complementary tools, informed by the detailed EPN analysis on Orkney). The outputs from this work can help guide the future development and deployment of these technologies, assessing the potential they can have.

When using EPN in a local area, it is usually necessary to break the whole system down into smaller analysis areas. Although the whole system is optimised together, some decisions are made at the analysis area level.

For example, domestic buildings are grouped into a large number of building archetypes, based on size and thermal parameters. This means that each individual building does not need to be modelled separately in a building energy model – instead only each archetype needs to be considered. When considering future pathways for these archetypes in the optimiser (e.g. the choices of future heating systems and insulation) decisions are made on an archetype and analysis area basis i.e. all buildings of the same archetype in the same analysis area follow the same pathway.

Analysis areas can be manually defined in the model but are normally built around the areas served by primary substations (as this allows consistency in the assessment of network reinforcements at that level). In the Orkney model the analysis areas reflect primary substations, with additional areas added to separate the built-up areas of Kirkwall and Stromness to provide greater resolution (see section 2.4).

2.3 Model Enhancements to Reflect Current Orkney System

As described in section 2.1, Energy Path Networks is a previously developed tool that has been applied to a number of different local areas and energy systems across the UK. However, as highlighted in section 1.2, the Orkney energy system has a number of highly distinguishing features. Consequently, to best represent the Orkney system in the EPN tool, it was necessary to carry out further development of both the tool and the methodologies and data used in it.

In addition, work was undertaken to ensure that the ITEG project technologies were best represented in the tool.

The following sub-sections (within this Section 2) set out the activities relating to the model, methodology and data development which customised the EPN approach for the Orkney energy system. These sections do not set out the full detail of the EPN approach (which is detailed to a greater extent in Appendix B); rather, they highlight the changes which were made from the historic approach to best represent Orkney.

2.4 Definition of Analysis Areas

As noted in section 2.2, the whole Orkney energy system is broken down in the EPN model into smaller analysis areas. These are based on primary substations, with additional areas added to separate the built-up areas of Kirkwall and Stromness to provide greater resolution.

The analysis areas are shown below in Figure 6.

Figure 6 – Analysis areas modelled in Orkney

The map shows the significant analysis areas containing domestic buildings. A number of other areas were used in the network analysis of the model to connect generation to the appropriate pieces of network, but do not cover a spatial area.

2.5 Changes to Electricity Network Representation

As discussed in section 1.2, the Orkney electricity network and its associated constraints form a crucial element of the Orkney energy system and act as a limiting factor for future developments. Therefore, it was important to ensure that the system was adequately represented in EPN. To assist with this, Scottish and Southern Electricity Networks (SSEN) provided detailed network data in both GIS and table form to allow a representation of the network to be built.

It is important to note that this representation is not an exact copy of the full network layout, but a simplification for the model that preserves the key attributes needed to consider network loads, headroom and costs of reinforcement.

2.5.1 Sub-Sea Electrical Transmission Links

It is necessary to define the electrical distribution links between each of the primary substations (i.e. between corresponding analysis areas), as shown in Figure 7 overleaf. The capacity of these links is a key factor in the future constraints of the system. The active power capacity of sub-sea links between islands was calculated from SSEN data[15] which gave dimensions and type of cabling installed and assuming a power factor of 0.9 (based on internal ESC expert advice).

SSEN data indicated that the link between Westray and Eday is usually left open[16], so this was deliberately omitted from the model.

Where an individual link is located wholly within a single analysis area, with a primary substation on one island serving more than one island, (i.e. those between North Ronaldsay and Sanday, and between Orkney Mainland and South Ronaldsay), these links have been modelled as 11kV feeders with network capacities and constraints represented in exactly the same way.

Within the model the flow of electrical power between islands and to/from the UK mainland is constrained to the capacities of these links. The inter-island capacities are upgraded under several scenarios. Upgrading the interconnector between Orkney and the UK mainland was considered as part of scenario 8 (see section 4.1.10), and there is further discussion of this in relation to the proposed West of Orkney Windfarm at section 5.3.

[15] Private data supplied to Energy Systems Catapult by SSEN

[16] 'The Orkney RPZ: Facilitating increased connection of renewable generation through active network management', November 2007, SSE Power Distribution and University of Strathclyde, downloaded from: https://www.ssen.co.uk/WorkArea/DownloadAsset.aspx?id=992

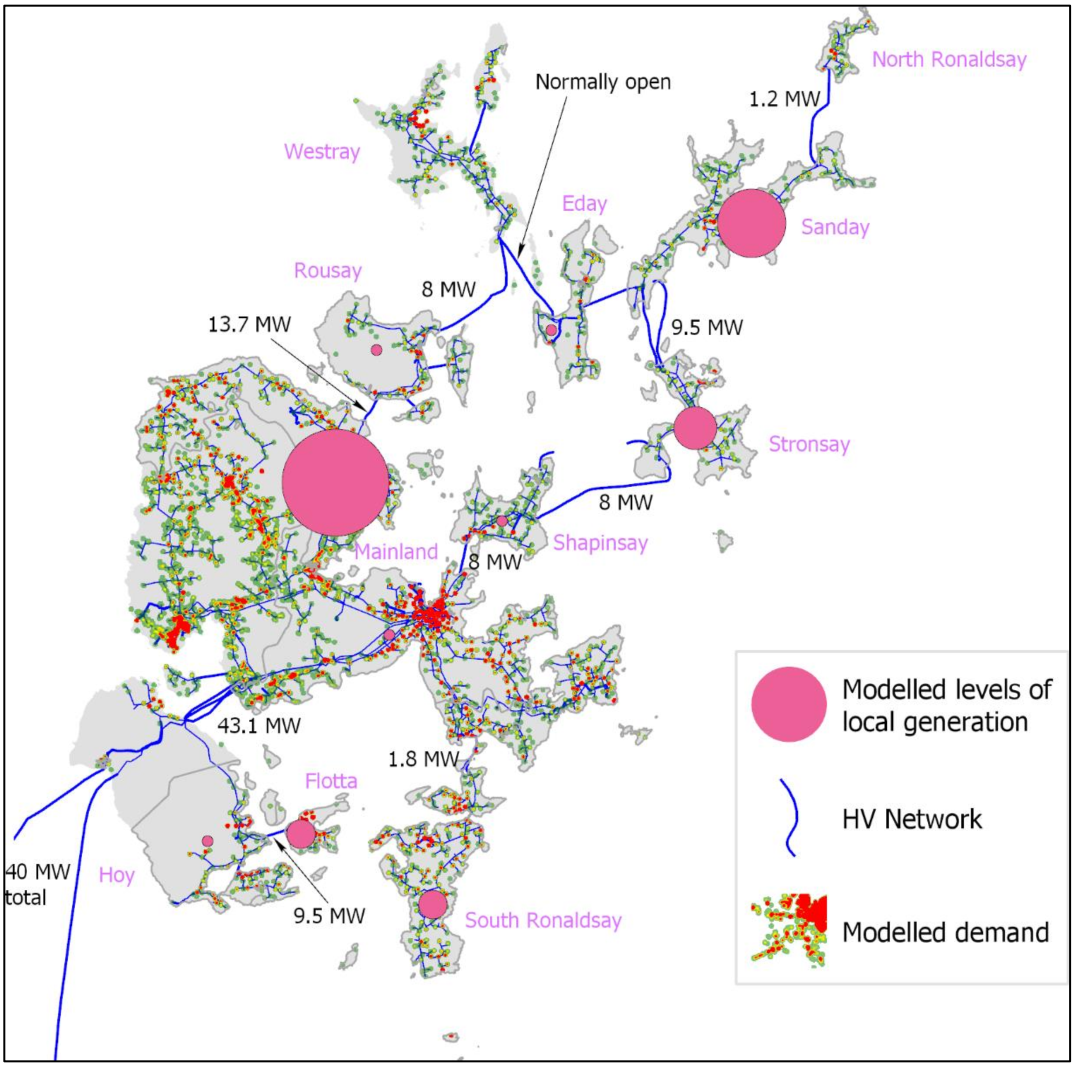

Figure 7 – HV network, local generation and initial modelled energy demand

2.5.2 On-Island Electrical Distribution Network

Within each analysis area there is a representation of the local electricity distribution network – comprising feeders from the primary to secondary substations, the secondary substations themselves and the low voltage feeders to end users.

In many instances the electrical components available in the EPN tool to represent the network were too highly rated to represent the Orkney network. In particular, the feeder sizes shown in the SSEN data were smaller than those normally represented in EPN. Table 1 shows the distribution of cable sizes in the SSEN data, with a large proportion of LV Cables and HV Lines below 95mm^2. There was also a notable amount of missing data, with approximately half of the HV line distance not having a cross sectional area stated. The bottom row of the table shows the proportion of total network length for each cable type. It can be seen that whilst information is missing on 98% of the LV lines these represent only 2% of total network length suggesting that approximating these network capacities based on estimates of current load will not produce large errors in the modelling.

Data was sourced to represent the physical attributes of these smaller cable sizes within EPN – mainly resistance and capacity for carrying current. Previously-used data sources for cables in

EPN did not have the physical specification for these components, and so they were instead collated from a number of different cable datasheets and catalogues that included appropriate sizes.

Table 1 – Proportion of Orkney feeders by size from SSEN data

Proportion of network length by each size in SSE data				
	LV Cable	LV Line	HV Cable	HV Line
13mm2				0.04
16mm2	0.07			0.17
25mm2	0.10			0.06
32mm2				0.14
35mm2	0.19		0.05	
38mm2				0.04
50mm2	0.03			
70mm2			0.18	0.06
95mm2	0.30		0.16	
150mm2			0.07	0.01
185mm2	0.10		0.09	
240mm2			0.16	
300mm2			0.15	
400mm2			0.03	
Other	0.11		0.09	
unknown	0.10	0.98	0.02	0.47
Proportion of Network length	0.29	0.02	0.14	0.55

In order to model the cost curves for network reinforcement, it is also necessary to understand the cost of the different feeder components, to account for the costs of putting new ones in place. Costs of components already in EPN have generally been sourced from network operators' assessments of the actual cost of reinforcement, as submitted to Ofgem. Despite best efforts, it proved impossible to source reliable cost data for the purchases and installation of these smaller cable sizes. It is believed that there is a large, fixed cost component in the cost of reinforcement and so it would not be appropriate to scale existing costs linearly downward in line with capacity. It was therefore decided to cost the smaller sizes as marginally below the cost of the larger cables where ESC had existing data. This means that the model is unlikely to install new versions of the smaller cables (as it could get increased capacity at a minimal cost), but it is considered likely that SSEN may wish to install more standard sizes if reinforcement was to occur.

A final adjustment to ESC's previous network methodology was to better account for long feeders with many buildings connected along the length. This is very common in Orkney, with long feeders following single roads across an island and individual buildings connected off it with pole mounted transformers across a large distance. A change was made to the spatial resolution at which ESC modelled feeder connections in order to allow accurate representation that the buildings were joining along the length of the feeder and capture what that would do to the connected feeder length for each building.

2.6 Better Representing Orkney Buildings

As discussed in section 1.2, the Orkney building stock has some distinguishing features compared to the 'typical' UK or Scottish stock. ESC has previously developed and proven approaches to modelling local energy systems using widely available data, such as Ordnance Survey AddressBase[17], MasterMap[18], Scottish housing condition surveys[19] and Energy Performance Certificates[20]. However, in order to accurately represent the Orkney energy system, it was necessary to identify and source a number of Orkney-specific data sources.

2.6.1 Orkney-Specific Data Sources

The Orkney Islands Council has previously sent an Affordable Warmth survey postally to all Orkney households. Results from this survey were made available to the project in an anonymised format.

A number of questions in the survey provided useful information to represent the Orkney building stock. These included:

- House Type
- Age
- Number of bedrooms (used as a proxy for size)
- Window Type
- Water and Space Heating Systems
- Loft insulation
- Wall type and insulation
- Water and space heating system

In total approximately 1100 responses were received, which when validated and cleaned for use in this project left 750 usable records. Analysing these results in combination with each other, i.e. by understanding how frequently the different combinations of the above factors occur, it was possible to develop a series of building archetypes for Orkney, and to weight them by how frequently they appeared in the survey dataset.

This dataset of archetypes was then combined with Ordnance Survey mapping data to project how the archetypes are distributed across the Orkney building stock. For example, the OS MasterMap data provided a geographical footprint polygon for each building. This polygon could be analysed to determine building type (e.g. terraced, detached, etc) and an estimate of the building floor area made. The building could then be statistically assigned to an archetype that also matched those size and type features, with a weighting assigned to those archetypes that appeared more frequently in the survey data.

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[17] https://www.ordnancesurvey.co.uk/business-government/products/addressbase-premium

[18] https://www.ordnancesurvey.co.uk/business-government/products/mastermap-topography

[19] https://www.gov.scot/collections/scottish-house-condition-survey/

[20] https://www.scottishepcregister.org.uk/

Although anonymised, the survey data did include the data zone of each response, giving five zones across Orkney. It was decided to not build separate archetypes for each data zone because in some cases the sample sizes were very small. Instead, the geographical distribution was captured by the different building sizes and types mapped from the MasterMap data. A comparison was made between the building attributes ultimately applied to buildings in each data zone in EPN and the total by data zone in the raw survey results and they were found to match satisfactorily.

2.6.2 Orkney Building Heights

In order to determine the floor area of a building it is necessary not only to understand the footprint but also the number of storeys. The floor area of a building is a significant factor when modelling its energy demands and the types of heating systems able to serve it. The approach used previously with EPN to estimate the floor area of a building was to find the size of the 2D building polygon in OS MasterMap data and then estimate the number of storeys by dividing the building height (sourced from OS building heights data[21], which is generated from LIDAR measurements).

At the start of this project, building heights data was not available for Orkney and so a number of alternative approaches were tested, including:

- Assuming all buildings were two storey
- Developing a classification approach on the building geometry and the attributes of surrounding areas
- Considering using EPC data.

None of these approaches was found to be satisfactory, as all underestimated the number of buildings believed to be single storey. This was found to have a particularly significant impact on the model of the energy system, since a small number of very large buildings were frequently improperly classified as two storey. This gave these buildings very large peak energy demands, limiting the heating systems considered to be able to serve them and having an outsized network impact given the number of buildings.

In May 2020, building heights data for Orkney was released, based on LIDAR data which appears to have been collected earlier in the year. Considering the poor performance of the previous attempts to estimate building storeys, and the significant impact this seemed to have on the energy system, it was decided to repeat the analysis with the new building heights data in place. This led to a notable reduction in the number of buildings modelled in the largest floor area bands.

2.6.3 Agricultural Buildings

Orkney has a large number of agricultural buildings with poor accompanying classification data in the Ordnance Survey datasets used.

The buildings normally appear in the MasterMap topography dataset as a building polygon, but don't have an accompanying address data point within the boundaries of the polygon in the AddressBase premium dataset. This means the buildings are not given a classification. This is

[21] https://www.ordnancesurvey.co.uk/business-government/products/mastermap-building

common in sites of non-domestic buildings, the AddressBase point represents the location of the address, but the address may correspond to several buildings (for example in a factory complex the address may match to the site office rather than a separate large factory building).

In the typical EPN approach these building get assigned classifications based on other nearby buildings, but this approach was found not to be suitable in Orkney as there were no appropriately classified buildings nearby. Generally, the closest classified buildings were domestic, which wouldn't help in modelling the agricultural buildings correctly. After some experimentation the following approach was taken to classify agricultural buildings in Orkney:

1. Building polygons without address points were selected, and filtered to a minimum size of $40m^2$ (to exclude garden sheds etc)
2. The proportion of land classified as Agricultural in OS MasterMap within 100m radius of these buildings was calculated (proportion of land only, excluding sea). A radius was required because the land directly surrounding the buildings themselves is normally classified as yard or hard standing rather than agricultural.
3. Where the building was selected in (1) and the proportion of agricultural land in step (2) was more than 50%, the building was classified as agricultural and given a benchmark with a low electrical demand.

A sample of buildings was checked using satellite imagery to confirm that the above method was suitable.

2.6.4 Distilleries

There are two distilleries on Orkney, and their power demands were investigated.

The Highland Park distillery in particular is a significant energy user and its impact would not be captured using a standard benchmark. Instead, its energy use was manually calculated based on two sources:

- the Orkney Energy Audit 2014 addendum which gives peat consumption of 1.43GWh/year at Highland Park
- Scottish heat map[22]

Peat is used for malting barley. Options to switch this energy consumption to low carbon were not included in the modelling since this would have required significant research to understand the possibilities. It was considered that this would bring limited benefits to the project. These emissions are unabated in all scenarios.

[22] http://heatmap.scotland.gov.uk/

2.7 Model Enhancements to Reflect Future Potential

Having added functionality and used new data sources to adequately represent the current Orkney energy system, a number of further modifications were made to the model to allow it to better represent the future options available in the Orkney area, with a particular focus on hydrogen infrastructure.

These are set out in the following sub-sections within this section 2.

2.8 Hydrogen Demand and Transmission

Hydrogen demand options were added to all domestic and non-domestic buildings – i.e. all domestic buildings were tested with the option for a hydrogen boiler and all non-domestic buildings were given a hydrogen option for their energy demands to replace the existing electric or oil systems.

Previous consideration of hydrogen within EPN has been in areas with an existing gas grid, which could be repurposed to hydrogen. To consider hydrogen in the Orkney context a number of new hydrogen distribution and transmission options needed to be added.

For transmission, the functionality to consider transport both by trailer on ferry[23] and also by pipeline was added into the model. For the former, transmission links have been included between the islands using the routes and frequencies of existing ferry services (with capacities limited to trailers on the ferry) and a time delay included to account for the travel time.

Note that the analysis in this project was carried out prior to information on the proposed Flotta Hydrogen Hub development becoming available, and so this option is not specifically modelled, although this is materially similar to scenarios which were modelled that include a large electrolysis facility assumed to be at Flotta. This proposed development is briefly discussed in section 5.3.

2.9 Representing Tidal Generation

For modelling of the energy system, the important characteristics of the tidal generator are the electrical output by time and, for potential scaling up of use of the technology within the Orkney energy system, the capital and running costs of a fully commissioned new installation. Electrical output is a function of the capacity of the system installed and the state of the tide.

To model the ITEG-specific tidal generator, a maximum power output of 2MW was assumed, as was advised by project partners at the time ESC was building that part of the model[24]. A small deviation from that in the final implementation would not have any significant effect on the lessons learned from the modelling.

[23] This has been modelled on the basis of a hydrogen trailer joining an existing ferry service. We understand that existing maritime safety regulations do not make this sharing possible, but it is imagined that these regulations might change over the time periods that we are considering.

[24] Presentation to the ITEG steering group meeting 3-4/4/2019

Tidal generation is predictable, making it an excellent complementary generation source to (inter alia) less predictable sources such as wind. However, its achievable output at any moment in time is determined by the tidal flow velocity, which is not constant (either throughout the day or over shorter timescales of seconds and minutes). It is possible to operate at a deliberately reduced output where that is advantageous to the operator or to the wider energy system, to provide network ancillary services for example. However, it is more likely (in the near term at least) that the primary business model for tidal generation will be to operate the turbines at maximum achievable output minute-by-minute and that is the assumption in the modelling reported here. It is therefore appropriate to model the turbine output as exogenously determined based on tidal flow patterns, not a variable within the control of EPN.

Tidal flow data was provided by EMEC[25] and converted from current speed to power output using a power curve derived from data provided by Alstom to the Energy Technologies Institute within the ReDAPT project in 2014[26]. The results for one week are illustrated in Figure 8 below.

Once the turbine has been in the water for a few months, it would be possible to repeat this analysis using observed turbine output and to re-run some of the model cases.

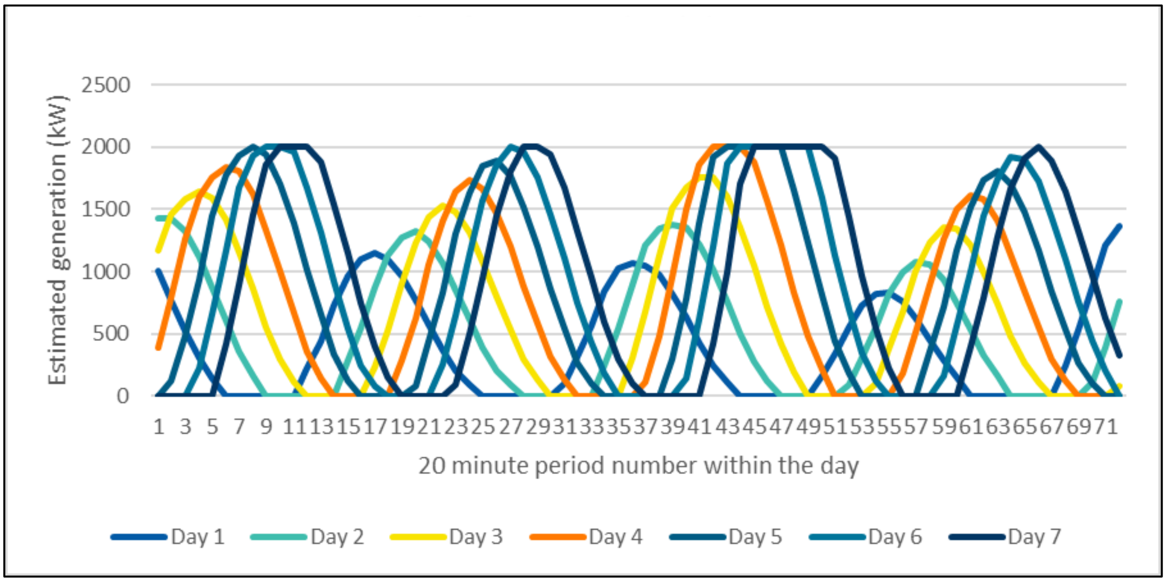

Figure 8 – Estimated tidal generation output for one week

The EPN model contains a huge amount of detail in terms of the buildings, networks and connected technologies. In order to avoid excessive model run times and complexity, trade-offs are designed into the EPN modelling framework. One of these is to limit the resolution with which time is modelled, but with careful choice of data this model can nonetheless be highly effective at capturing the range of system conditions which a network needs to cope with. All energy demands are initially calculated for 30 minute time periods for different seasonal days. This ensures that peak demands are captured alongside annual and seasonal demands. These are then aggregated to align with the generation profiles described below.

[25] Current speed data for Berth 5 output in 1996 at 20 minute intervals, extracted 3/6/2019 and provided to ESC by EMEC

[26] Title: ReDAPT MC7.1 – Initial Power Curve, ETI reference: OCEDG4--GENALL0007BB, Date: 06/05/2014, Author: Alstom Ocean Energy, available to download from: http://redapt.eng.ed.ac.uk/library/eti/reports/MC7.1%20%20Initial%20Power%20Curve_A.pdf

Judicious choice of data is required to ensure that annual and seasonal energy generation is correctly represented whilst also capturing the fact that peak tidal generation shifts daily in relation to periods of peak demand and the influence this can have on the wider energy system. In the representation illustrated in Figure 9 below and used in this modelling, three representative days (winter, summer and the time of peak winter demand) are used. Each day is divided into three parts. *Off Peak* represents the overnight period. *Midday* represents the whole daytime period excluding the absolute peak period*. Peak demand* represents that absolute peak demand seen within the day. These combined ensure that security of supply constraints and network capacity requirements are met.

- The peak demand day is modelled as a day of low output at the 1 percentile level (i.e. only 1% of days have lower output) and zero output at the peak in that day. This worst case ensures that the network has sufficient capacity to deliver secure supplies, even under such conditions. This is done to ensure the system is robust against periods of low tidal generation. Wind generation is also defined to be low on that day.
- EPN has two other representative "days", a summer day and a winter day. In order to ensure they have different energy output within the day a 10% bias towards summer generation was allowed. This was a judgement between modelling the range of daily energy output and overly distorting seasonal energy. The summer day was chosen to show the variability within a day. The winter day is more of an average value applied nearly constantly across the day, with less at the peak to stress test the system.

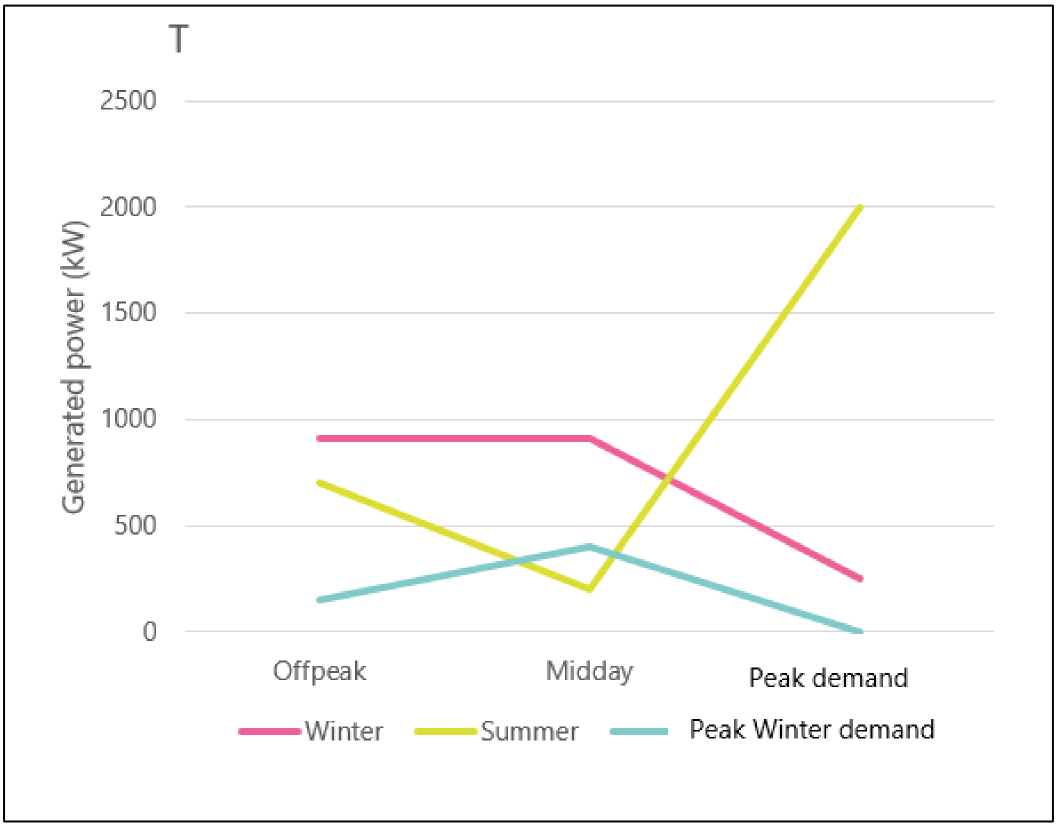

Figure 9 – Simplified tidal generation profiles using seasonal representative days

Costs for installing further tidal turbines were taken from ESC's ESME model, version 4.4 (last updated and released to the ESME user community under licence in 2016)[27] and compared against n'th of a kind costs supplied by Orbital[28]. Future costs were assumed to decrease in a straight line from present costs to n'th of a kind costs in 2050. See Figure 10.

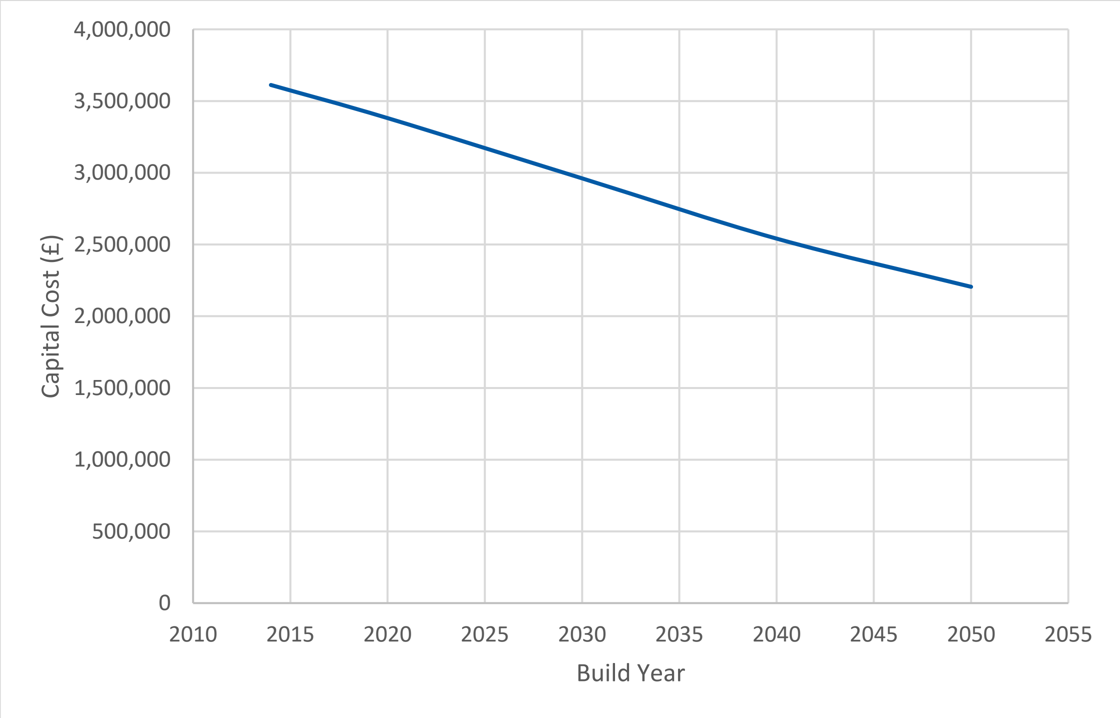

Figure 10 – 2MW tidal turbine installed capital cost trajectory

Other items of data necessary for the representation of the tidal turbine within the EPN model, such as technical and economic lifetimes, were drawn from pre-existing EPN datasets within the ESC.

[27] ESME Data References Book, 2017, https://www.eti.co.uk/programmes/strategy/esme/

[28] Information provided to ESC privately by Orbital Marine Power in February 2019

2.10 Representing an Electrolyser

Unlike a tidal generator, an electrolyser (of the Proton Exchange Membrane type) can be run on command at any time and at any level of output up to its nameplate power. The operational profile of the electrolyser is thus left at the disposal of the EPN model so that it can be matched to the wider energy system considering things such as hydrogen demand and renewable generation.

Rated capacities and conversion efficiency for the electrolyser were provided by ITEG project partners.[29] Details are a maximum power input of 0.525MW with 0.5MW delivered to the electrolyser, 0.025MW used by auxiliary equipment, primarily a compressor. This is modelled as producing a maximum output of 0.4MW of Hydrogen.

The EPN tool is deliberately designed with limited resolution of time modelling, as discussed in section 2.9 above. It was therefore not possible to model (at a very granular level) the ITEG electrolyser's short-time overload capability (i.e. an ability to run at a greater power for 30 minutes). The 13-hour cycle of tides means that this can only be used twice a day if using tidal generation to power the electrolyser. The capacity factor for a 0.5MW electrolyser supplied by a 2MW tidal turbine is high on all but the lowest tides. The extra 0.5MW x 0.5 hours x 2/day represents 0.5MWh/day makes little difference (perhaps 5% increase) to the overall hydrogen production as modelled which is small in the context of the other uncertainties within the modelling.

Observation of the profiles of tidal generation in the previous section quickly make it clear that this capability makes very little difference to the ability of the electrolyser to match its input to the output of the tidal turbine and is therefore likely to be used for provision of flexibility to the wider system. ESC has other tools such as its Storage and Flexibility Model which are designed to focus in on whole-system flexibility with much greater time resolution and this capability would be relevant in that modelling. However, for the purposes of the investigations in this ITEG project, as provision of ancillary services was not a primary focus, a more broad-brush approach is taken to ensuring the resilience of the system and security of supply (see section 2.13) and hence the exclusion of this feature is not material to the outcome of the analysis. A minor adjustment could be made, such as increasing the average full power slightly, to account for this capability at a future iteration, if discussion with partners and/or analysis suggested that peaking was likely to be very frequent.

A lifetime of 25 years and availability of 90% for the electrolyser were taken from a report by E4Tech and Element Energy for the Fuel Cells and Hydrogen Joint Undertaking issued in 2014[30]. Costs for installing further electrolysers were taken from ESC's ESME model, version 4.4[31] (Figure 11). Water use by the electrolyser is considered to be out of scope and is not included in the modelling.

[29] Presentation to the ITEG steering group meeting 3-4/4/2019

[30] 'Study on development of water electrolysis in the EU', Element Energy and E4Tech, February 2014, downloaded from https://www.fch.europa.eu/sites/default/files/FCHJUElectrolysisStudy_FullReport%20(ID%20199214).pdf

[31] ESME Data References Book, 2017, https://www.eti.co.uk/programmes/strategy/esme/

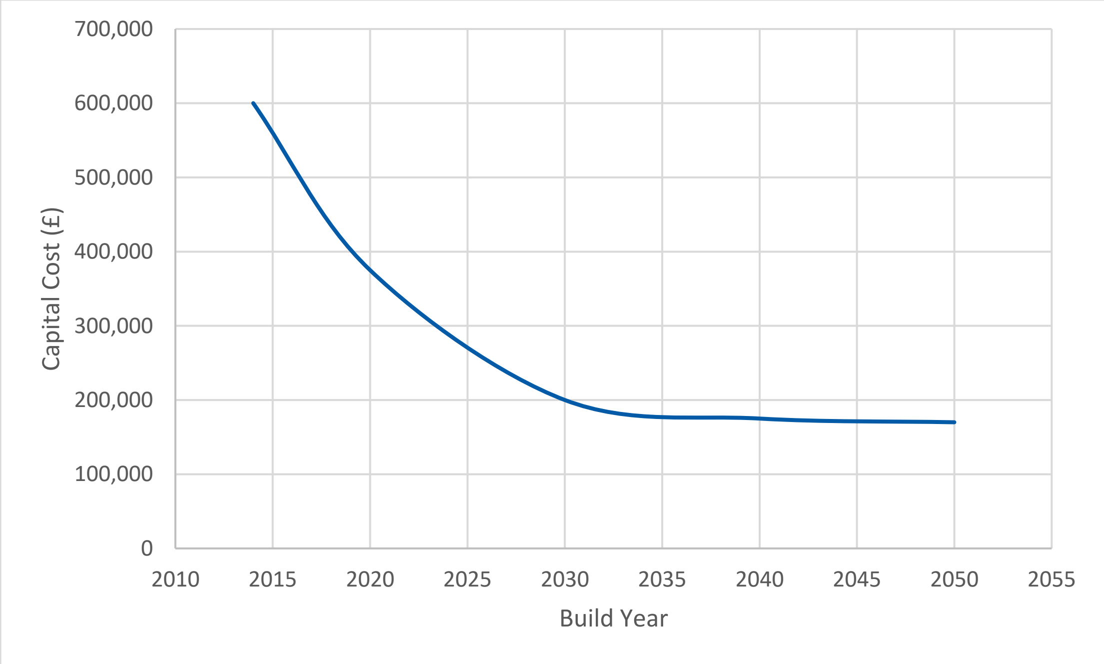

Figure 11 – 0.5MW (electrical) electrolyser installed capital cost trajectory

2.11 Control Strategies and Energy Management System

The Energy Management System (EMS) for the Eday site was specified and procured by EMEC. Numerous control strategies are theoretically possible for the tidal turbine and electrolyser, and various strategies are used in the analysis undertaken by partners within this project in order to explore particular questions.

For the purpose of this EPN modelling, the key control strategy features and assumptions which have been modelled are summarised below.

The tidal generator is assumed to be run to maximise the power output at all times. This maximises the usable energy extracted. Power generated can be fed to the on-site electrolyser or directly onto the grid or split between the two; the model is free to choose whatever is most advantageous to the whole system.

Unlike a tidal generator, an electrolyser can be run on command at any time and at any level of output within operating parameters. The activity of the electrolyser is thus left at the disposal of the EPN model to be run in whatever way is best. "Best", in the context of this modelling, means least cost solution for the whole Orkney energy system.

ESC modelled various scenarios when considering scaling up of the ITEG technologies:

- One where the electrolyser can only use electricity from tidal generation
- An alternative in which the model is free to choose whether to use tidal generation to power the electrolyser or to export it to the grid, or to use some for the electrolyser and export the rest
- A third option in which the tidal power is exported to the grid (within network constraints) and the electrolysers are powered using grid electricity.

In each case, the model will make the choice based on the least cost for the whole system (not maximising value for the asset owners, although market and regulatory design might cause the two to converge). In this case the model is free to import power from the grid to power the electrolyser. We understand this not to be the case for the ITEG project assets, but exploring these options may demonstrate wider system benefits. This option also allows electrolysers to be located away from renewable generation sites.

There are alternative strategies for running the plant, such as maximising the revenue for the operator or maximising the hydrogen output. These are perfectly valid strategies but the aim of the EPN model is to minimise system cost and it is therefore implicitly assumed that the regulatory and commercial environment leads individual technology owners to operate to the benefit of the whole system.

The site has operational flexibility arising from the choice of power usage (i.e. turbine output allocated to the electrolyser or to export or both). The model includes a 1.76MWh flow cell battery located at EMEC's Eday site.

2.12 Wind Generation

Existing wind farms were defined with size, location and rating details as listed in the Renewable Energy Planning Database[32]. Additional wind assets were made available for EPN to choose to build at a cost in one scenario exploring the option of upgrading the electricity network to the UK mainland (in line with SSEN proposals) to allow a significant increase in wind or tidal generation with associated export.

Note that the analysis in this project was carried out prior to information on the proposed West of Orkney Windfarm development becoming available, and so this option is not specifically modelled. The potential impact of this development is briefly discussed in section 5.3.

Wind generation is variable, is much less predictable than tidal generation, and (assuming that it is operated to maximise energy generation) is not controllable other than curtailing output when the network cannot handle it (or to provide ancillary services). Wind generation is therefore represented in the EPN model in a similar manner to tidal generation in that the level of output through time is pre-determined, scaled up or down only by the capacity of wind generation which the model chooses to install.

Note that it is the uncurtailed, technically feasible, level of generation which is prescribed to EPN. If this cannot all be consumed locally or transported to be consumed elsewhere, including on the UK mainland, then its output is effectively curtailed. As there is no value in such curtailed output, the model will tend to take action to minimise curtailment, including by converting more heating from oil (for example) to electricity, but only where this is cost beneficial.

Data on historic wind resource by time was obtained from the Renewables.Ninja website[33]. The tool on this website estimates power output for each hour for a range of different turbine models and sizes. Data for 2016 was used. The Renewables.Ninja data was validated by comparing the annual load factors of wind farms estimated from their data with estimates given in a report by Baringa to DECC and the Scottish Government[34]. Validation of the level of curtailment for the current system is discussed in section 3.1.

As with the tidal generation (explained in section 2.9, it is necessary to represent the range of variation in wind generation within the constraints of the set of time periods and typical days modelled by EPN, as shown in Figure 12 below. In doing so the aim is to accurately represent both the total annual energy available and the stresses that its variability imposes on the rest of the energy system.

- To that end, the Winter season was represented by constant generation at an average level. Note that an ESC statistical analysis of the modelled Orkney wind data shows that wind strength tends to be fairly constant through the day so this is a likely case.
- For Summer an unlikely diurnal pattern was chosen, in order to explore the maximum generation but keep seasonal energy reasonable and annual energy to the correct level.

[32] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/795492/renewable-energy-public-database-q1-2019.csv/preview

[33] https://www.renewables.ninja/

[34] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/199038/Scottish_Islands_Renewable_Project_Baringa_TNEI_FINAL_Report_Publication_version_14May2013__2_.pdf

The maximum output was timed to coincide with the modelled maximum output from the tidal generator to properly stress test the system.

- For the peak demand day a very low wind generation again provides a worst-case scenario which ensures the model builds sufficient capacity to provide a reliable electricity supply. In this case the profile for a particular day in 2016 was chosen so it is an entirely credible profile. The resulting profiles for a 500kW wind turbine are illustrated in Figure 12 below, plotting the load factor by time of day.

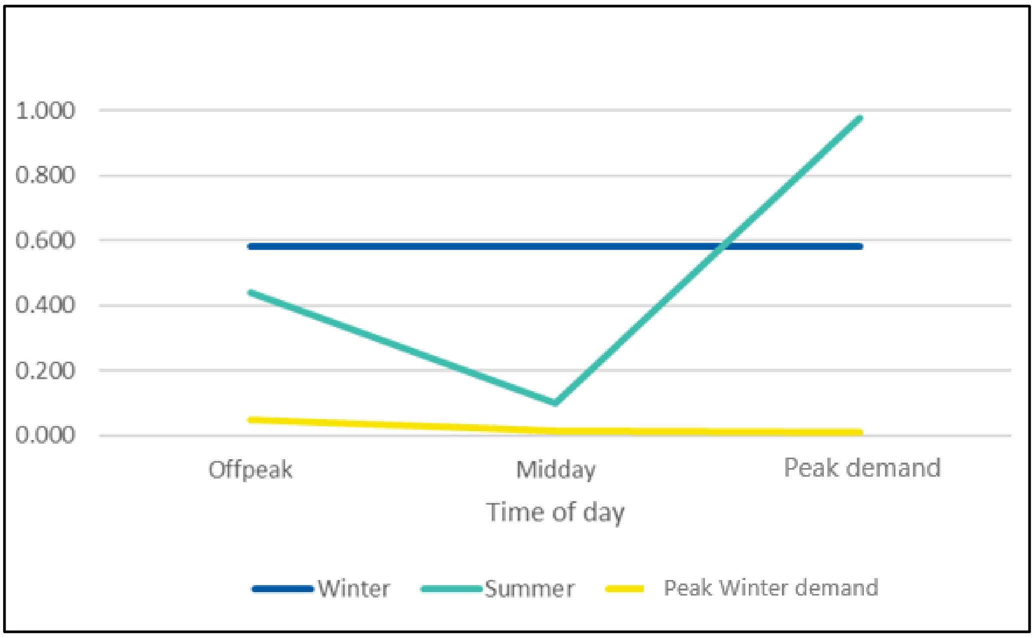

Figure 12 – Simplified wind generation profiles using seasonal representative days

2.13 Capturing Security of Supply Risks

The model includes a number of security of supply constraints that ensure the energy system functions under a scenario where infrastructure experiences reduced capacity or degraded performance. For electricity networks a minimum headroom of 5% more than calculated peak demand must always be available. In addition, de-rating factors are applied as percentages of maximum current limits for each asset's specified thermal rating to reflect the n-1 contingency. These are largest for HV transformers at 60% and reduce for HV feeders, LV transformers and LV feeders.

Hydrogen technologies and infrastructure were added to these security of supply tests. De-rating factors are used to represent unavailability during multi-day-without-supply stress periods. These are applied as percentages to utilisation of energy in storage, energy import capacity and local energy production capacity to ensure that availability over all sources of supply is sufficient to meet demand during peak periods. Furthermore a hydrogen flow speed is specified to reflect the time taken to ship hydrogen using trailers on ferries.

3 Model Validation

3.1 Validation of Initial Conditions

One test of the validity of the model of the Orkney Energy System which ESC has developed is that the energy supply and usage estimated by the model for 2020 is in reasonably close agreement with recent historical observations – in other words, that modelled future system developments are starting from the right place. This is partly because the model starts from the system a few years before 2020, but most importantly because the system is modelled from the bottom up without having complete data available at that granularity, so it is necessary to check that this results in an accurate system at macro level.

A case was therefore run with no incentive to reduce carbon emissions, merely to satisfy all energy demands, at least cost, and a few key statistics compared with historical data. For many items the data in the model is estimated and entered at a detailed level so a check that this bottom-up estimate concurs with high level figures is valuable. For a few items such as flows around the system and the level of wind curtailment the model has free choice so again comparison of aggregate model output against observations is valuable. A few key statistics are compared here.

The Orkney Energy Audit 2014[35] contains an estimate of average total annual electricity consumption in Orkney of 156GWh over the period 2009 to 2013. This compares with UK Government statistical estimates of 138 to 140 GWh per year from 2013 to 2018[36]. The Energy Audit does not give details of the calculation behind their figure but does reference the UK Government statistics. It could be that the Energy Audit figure has added back into it an estimate of demand met by on-site generation such as solar PV which would not show in metered data. The bottom-up estimate within the EPN model is 165 GWh per year in 2020. The discrepancy is deemed acceptably small.

The capacity of wind generation as stated in UK Government statistical reporting[37], was 51.3MW in 2019. The model is constrained to use a limited set of wind farm sizes but gets very close to that figure at 50.7 GW, which is acceptable.

Annual wind generation is variable depending on climatic conditions prevailing each year. Between 2016 and 2019 the installed capacity did not change but annual output varied between 166 GWh and 189 GWh[38]. The (curtailed) 2020 wind generation estimated by the EPN model is 186 GWh giving a curtailed load factor of around 42%[39]. That this is in line with historical values

[35] 'Report to Orkney Renewable Energy Forum', August 2015, downloaded from: http://www.oref.co.uk/wp-content/uploads/2015/09/Orkney-wide-energy-audit-2014-Addendum-2015.pdf

[36] https://www.gov.uk/government/statistical-data-sets/regional-and-local-authority-electricity-consumption-statistics

[37] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/834142/Renewable_electricity_by_local_authority_2014_to_2018.xlsx

[38] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/834142/Renewable_electricity_by_local_authority_2014_to_2018.xlsx

[39] Theoretical load factors calculated from wind speed data and a turbine power curve are more like 52% so this is an overall curtailment of around 20%.

indicates not only that the modelling of the current wind farm capacity and operation is accurate but is also a good test of the representation of the constraints within the electricity network as it is these that determine the level of curtailment.

3.2 Reconciliation of Carbon Emissions

Table 2 overleaf compares the carbon emissions for Orkney reported by UK government with the values estimated by the EPN model for 2020. Key points are discussed below.

The EPN model does not include emissions from the following sectors:

- Land use, land use change and forestry
- Agriculture except as electrical and gas consumption in farm buildings
- Liquid fuel in transport

Such non-energy-sector emissions are typically estimated off-model in the event that overall carbon emissions are considered for a modelled area, and the carbon targets for the energy sector itself adjusted accordingly in the input data to EPN.

Differences in the way properties are categorised as domestic or industrial mean it is more helpful to compare estimates of emissions from the two combined than separately. When emissions from electricity consumption are excluded, the estimates of combined emissions from domestic and industrial properties for 2018 from BEIS and for 2020 in the EPN are virtually identical. This equivalence is a little flattering because the UK government figures are for all greenhouse gases, converted to carbon dioxide equivalence, whereas the EPN only accounts for carbon dioxide.

A significant difference is seen in the carbon emissions allocated from imports of electricity from the UK mainland. Imports of electricity from the UK mainland are decided within the EPN model as part of the optimisation. While it was possible to check that the EPN model correctly has a near-balance position between imports and exports it has not been possible to compare the actual levels of imports and exports to observed data. The higher level of emissions from imported electricity strongly suggests that EPN is estimating a level of imports and exports some 50% higher than has been observed historically. It could also be that the grid emission factor applied (in the early years only) differs from that used by UK Government; that applied within EPN comes from the output of another of ESC's models, namely ESME (Energy Systems Modelling Environment). The model is required to give us the forward system view of carbon content and energy costs for the modelling out until 2050.

Despite the difference from imported electricity the overall level of carbon dioxide emissions estimated by EPN for 2020 is close enough to historical estimates of emissions in 2018 to have confidence that the modelling is representing the current Orkney energy system. The main focus of the modelling is on the technological changes needed to drastically reduce those emissions, not on estimating the emissions themselves, and there is no reason here to doubt conclusions about these choices.

Table 2 – Reconciliation of Orkney carbon emissions

CO_2 Emissions (kt/year)	UK Gov't Data for 2018[40]	EPN model output	% Delta	Notes
Domestic (excluding electricity)	24.9	17.3	-31%	BEIS class any electricity customer with a profile 1 or 2 meter and using less than 100,000 kWh a year as domestic. For EPN we attempt to refine that allocation. This leads to fewer buildings being categorised as domestic in EPN and explains the lower emissions.
Industry, Commercial and Public Sector (excluding agriculture and electricity)	16.9	24.5	+45%	Most agriculture is outside the scope of the EPN model. Electricity is accounted separately in EPN so separated out here. A corollary of EPN categorising fewer buildings as domestic is that more are marked as industrial, hence the discrepancy.
Combined Domestic + Industry, Commercial and Public Sector (excluding agriculture and electricity)	**41.8**	**41.8**	**0%**	When the two categories are combined the match is surprisingly good.
From electricity consumption	32.4	47.7	+47%	The electricity consumed on Orkney is all (or virtually all) either from renewable sources locally, so zero carbon, or imported from the UK mainland. The difference must therefore be related to imports.
Total (excluding agriculture and transport)	**74.3**	**89.5**	**+20%**	The differences between the UK Government data and EPN model output are chiefly due to the estimation of the carbon content of electricity imports from the UK mainland.

[40] https://www.gov.uk/government/statistics/uk-local-authority-and-regional-carbon-dioxide-emissions-national-statistics-2005-to-2018

3.3 Validation Against Operational Data

As further data becomes available over the course of the project, ESC will endeavour to validate its representations of the ITEG technologies (tidal turbine and electrolysers) against the performance of the technologies as deployed. This would be relevant to scenarios with just the ITEG technologies, but also help validate scenarios where the technologies have been made available at a larger scale of roll-out.

4 Overview of Results

4.1 Scenarios Used

In looking at the Orkney energy system from the present day until 2050 there is significant uncertainty. The system of the future will be shaped in part by the technologies and options available to it. To explore a range of possibilities, a number of different system scenarios have been defined with differing sets of options available.

These scenarios define the inputs to the EnergyPath Networks framework. They do not specify particular energy system solutions as fixed outputs. Instead, the EPN optimisation tries to find the optimal energy system under the different sets of inputs.

This means that the resultant energy system (the optimisation output) may not change between scenarios if the changes in inputs do not change the lowest cost solution; for example, a scenario where extra technologies are made available may not lead to a change if the model finds these extras technologies to be less desirable than existing alternatives.

The scenarios defined in this work build on each other in a logical manner, with each scenario adding more available system/technology options, as shown in Figure 13. For scenario 6 a series of runs were completed to explore the influence of hydrogen market price on the optimised results. Similarly, for scenario 7 sensitivities to hydrogen and electricity market prices were conducted.

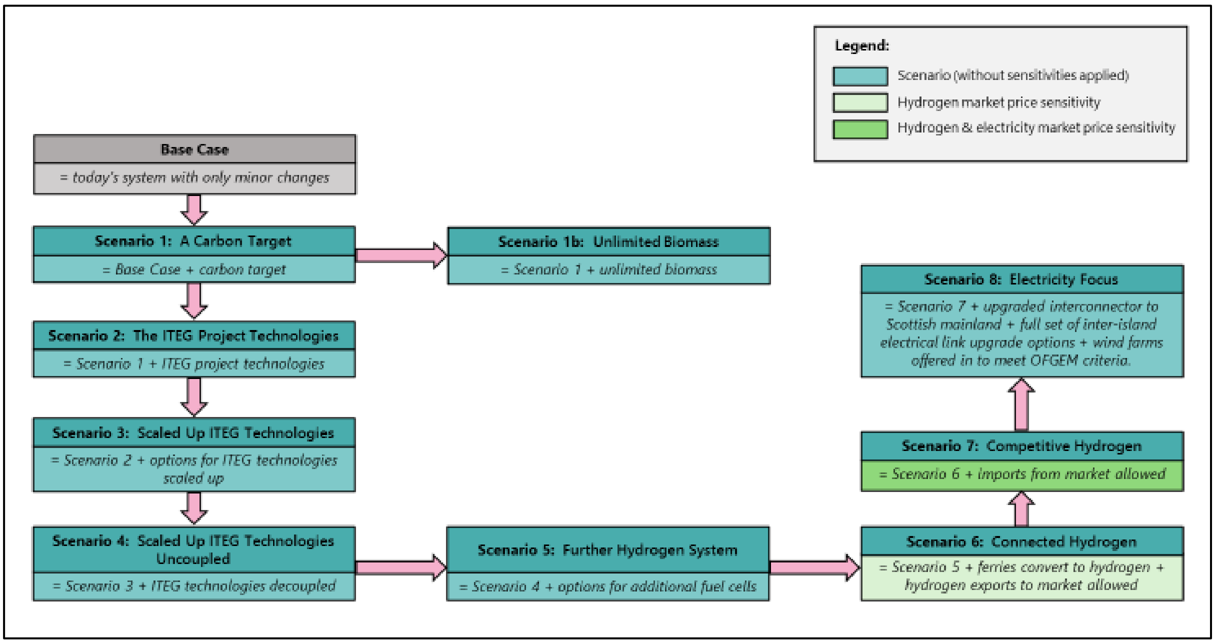

Figure 13 – The scenarios studied in this report

The scenarios are described overleaf.

4.1.1 Base Case

This is not a modelled scenario but the starting reference upon which the scenarios are constructed. It represents the current Orkney energy system.

It is convenient to note here some of the features modelled in all scenarios which have been added or updated since the initial report in December 2020. These are chiefly options for technological interventions to the Orkney energy system available for the optimisation model to call upon at any time in the period 2020-2050 and include:

- Revision and additions to the options for converting to electrical heating in non-domestic buildings
- Options to install heat networks, with hydrogen boilers, heat pumps and hydrogen fuelling
- Addition of the Invinity flow-cell battery on Eday
- Revision of the costs of installing onshore hydrogen distribution networks
- A number of technical amendments to improve the modelling of hydrogen distribution
- Updating the estimate of UK national grid electricity prices and grid emission factor to ESC's latest estimates based on net zero modelling
- Costed options for upgrading inter-island electrical network connections added.

4.1.2 Scenario 1: A Carbon Target

In this scenario a carbon target is applied to the Base Case. This carbon target forces the model to cut the emissions to as low a point as possible by 2050, but it does not reach a point of zero emissions due to two main factors:

- Firstly, net zero is likely to require some mitigation of remaining emissions through carbon capture and storage, or through land use and forestry change, generating negative emissions. These are not within the scope of this local energy system model (although they can potentially be assessed off-model at a later stage of analysis).
- Secondly, where there is uncertainty about options to decarbonise, a cautious position is selected. For example, for some classifications of non-domestic buildings electrification options are not made available, as in some cases they would not be suitable for the processes in those buildings. Having identified these hard to decarbonise activities, specific and detailed site by site engagement is required to understand the options (and this is beyond the scope of the present modelling). In some cases an option is available to switch these buildings to low carbon hydrogen but this is not available in sufficient quantities in scenarios 1 and 2 to allow this option to be selected.

In the intermediate time periods (between now and 2050) the model is forced to decarbonise progressively over time. The target for 2020 is set to 69ktCO_2/year in 2020, derived from the latest available published data of 74.3ktCO_2/year in 2018[41]. As the last modelling period covers the years 2045 to 2050 and the target is set to be zero in that period the model effectively

[41] Source: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/894787/2005-18-uk-local-regional-co2-emissions.xlsx. From this data an estimate was made of the emissions which are included in the model.

applies the Scottish Government target of net-zero by 2045. The target in intervening years is assumed to decline linearly. Should emissions exceed these targets a penalty price of £10k/T.CO_2 (£10m/kTCO_2) is levied.

In this scenario the model finds ways to reduce the carbon emissions to 3.3ktCO_2 per year by 2050. This is achieved primarily through electrification of heating coupled with energy efficiency improvements.

Biomass usage is limited to the quantity estimated to be used in the present day Orkney energy system[42]. This amounts to an energy content of 91MWh per year and the model chooses to use it to supply domestic heating.

The existing electrolysers on Eday and Shapinsay are included. By 2050 they are contributing 2GWh of energy in the form of hydrogen which is used in domestic heating.

The increase in electricity supply required to meet the demands of electric heating and to run electrolysers is provided by increased imports from the UK mainland and by local solar PV installations.

4.1.3 Scenario 1b: Unlimited Biomass

As above but without the biomass restriction referred to in section 4.1.2. This is a side-scenario to demonstrate the extent to which the model will use biomass if available.

Previous ESC modelling demonstrates that in other regions, and nationally, biomass can be a highly attractive option but is also highly price dependent and so is high risk. The quantities of biomass required would mean large imports onto Orkney, which would increase the cost. By 2050, national scale modelling has shown that biomass is likely to be in demand from a number of different parts of the energy system which are hard to decarbonise. As an unregulated product, users would have to pay the market price when there is competition.

A heavy commitment to biomass infrastructure is therefore a high-risk choice, reliant on the unknown future price. For this reason, the quantity of biomass available has been limited in the main scenarios.

In this side-scenario an unlimited quantity of biomass is assumed[43] to be available at a cost of £28/MWh in 2020 rising to £55/MWh in 2050. At those prices the model chooses to use biomass to meet 5% of the Orkney system's energy needs, the vast majority of it used in non-domestic buildings. The biomass displaces oil and a small amount of imported electricity. In 2050 CO_2 emissions are reduced by 600t/year to 2.7ktCO_2 /year.

[42] The Orkney energy audit was unable to put a figure on this, so the max allowed quantity is a modelled output based on ESC projections of buildings with biomass systems and the amount of heat they would need to produce. Although the quantity of biomass used is capped, the model can change how and where it is used as appropriate.

[43] Costs are derived from the validated ESME model dataset.

4.1.4 Scenario 2: The ITEG Project Technologies

As scenario 1, but with the ITEG project technologies as planned[44] in this project also deployed in the model – primarily the tidal turbine and electrolyser plus storage. In this scenario, deployment is limited specifically to the single demonstration unit on Eday. This makes a small amount of hydrogen available to the system. The demonstration units comprise a 2MW tidal generator and an electrolyser capable of drawing 1MW of electrical power but only for a limited period. In our modelling we have rated the electrolyser at 0.5MW, the level at which it can draw power continuously. This fits best with the rest of the chronological modelling such as tidal profile and profiles of electrical and heat demand (see section 2).

It was not possible to model the full complexities of the electrical network at the EMEC site on Eday. In this model the electrolyser is only able to use power generated by the tidal generator. Power from the generator, however, can either feed the electrolyser, charge the Invinity flow cell battery onsite or export onto the local distribution grid, or a mixture of these. Hydrogen produced can be stored in a trailer onsite and shipped to other islands. Discharge from the flow cell battery can be used to feed the electrolyser or be exported.

The main impact of adding these technologies to the Orkney system is to reduce the level of imported electricity by around 300MWh per year. The additional hydrogen produced is used in non-domestic buildings.

Use of the Invinity flow cell battery is broadly similar in all scenarios with one full cycle per day. Despite this, around 5% of the potential tidal generation is curtailed in this scenario because there is no outlet for it. From 2030 onwards all of this curtailment happens in the summer peak time period when we have modelled tidal resource as hitting the maximum possible value so that the potential output is the full nameplate capacity of the turbine. This was a deliberate stress test of the system (see section 2.9).

Note that the EPN characterisation of within-day variations only allows an approximate view of the level of curtailment and the operation of diurnal storage but is good enough to give confidence that the flow cell battery is providing significant benefit and, as we will see later, an indication of system designs which are likely to reduce the level of curtailment. Similarly, EPN does not allow us to include the peaking load of the electrolyser which may further mitigate curtailment of the tidal generator. In practice the flow cell battery may be used more than this and curtailment may be less. A model focussed solely on the particular site and immediate environment and with a time resolution of a 10 minute steps is recommended for more accurate estimation of these outcomes for a potential investment.

[44] Refer to notes in section 1.1 regarding changes to project objectives and to the installed equipment, and to the fact that these have no material impact on the conclusions of the analysis presented.

4.1.5 Scenario 3: Scaled Up ITEG Technologies

During the ITEG project itself, a single demonstration unit is being tested. If it is shown that this can be cost-beneficial to a net zero carbon energy system on Orkney, then further installations may be built – of both similar and larger sizes. For the purposes of this scenario, only the larger sizes were made available to the model. There are many sites with good tidal resources. Scenario 3 is therefore similar to scenario 2, but with a number of large-scale tidal generation and electrolysis packages available to the model as options representing this wider roll-out and scaling up.

For the purposes of this initial system modelling, the larger size packages are represented as single ('black box') units, although in reality these may be arrays of smaller units. Parallel work in Activity LT.2 'De-risking Future Projects' – particularly the work associated with deliverable LT.2.3 on Modularisation and Replicability – will assess options for unit sizes, ratings and modularisation strategies.

In this scenario a total of 2GW of tidal generation options are made available in locations around the Orkney archipelago with sizes in proportion to the estimated resource in those areas[45]. These are shown in the table below identified by the island where the power is deemed to connect to the distribution network:

Table 3 – Tidal generation made available for deployment in scenario 3 and subsequent scenarios

Location	Tidal Resource available
Rousay	20MW
Stronsay	220MW
Eday	360MW
Sanday	120MW
Westray	240MW
Hoy	600MW
South Ronaldsay	360MW
Shapinsay	80MW

In each case, this tidal generation is packaged with electrolysis with a capacity one quarter of that of the tidal generation – the same ratio as employed in the ITEG project installation on Eday where a 2MW tidal generator is coupled with an electrolyser with continuous power rating of 0.5MW.

The model is free to choose to deploy packages in each listed location, or not to do so. If deployed, both tidal generation and electrolysis have to be installed together and co-located. In this scenario the model is not free to choose just one or the other.

[45] Simon P. Neill, Arne Vögler, Alice J. Goward-Brown, Susana Baston, Matthew J. Lewis, Philip A. Gillibrand, Simon Waldman, David K. Woolf, The wave and tidal resource of Scotland,

Renewable Energy, Volume 114, Part A, 2017, Pages 3-17,

ISSN 0960-1481,

https://doi.org/10.1016/j.renene.2017.03.027.

(https://www.sciencedirect.com/science/article/pii/S0960148117302082)

In each location the model is given the choice of a package of 20MW tidal generation plus 5MW electrolysis, or a package scaled up to use the full tidal resource there. Capital costs of the generators and electrolysers are assumed to scale linearly with nameplate capacity.

The model chose to install only the smaller (20MW tidal) packages and in the following locations: Hoy, South Ronaldsay, Rousay, Eday and Westray (see Figure 14).

The lifetime of these packages is assumed to be 20 years. The model choses to install packages at different times through the study period with some capacity installed in every decade to 2050. In most cases those that are installed early enough to reach the end of their life by 2050 are renewed so that they are still in operation in 2050, although this is not the case for the package installed on Rousay which would therefore not be available in 2050; (Note that this is a modelling output, based on evolution of the whole system over time, rather than a strategic input choice).

The option to invest in hydrogen distribution infrastructure is also made available in most areas and costed options are made available to invest in hydrogen pipelines connecting many of the islands or in new ferries with increased capacity for hydrogen distribution by tube trailer. The model chose to invest in hydrogen pipelines connecting Hoy to Flotta, Westray to Eday, and Westray to Rousay. In addition it invested in increased ferry capacity for transport of hydrogen between Orkney Mainland and Rousay.

The locations of the tidal packages chosen in this scenario and of the hydrogen transport infrastructure, new and pre-existing, most used by the model are shown in Figure 14.

The additional electrolysers allow hydrogen production to be increased and for hydrogen to displace oil in those non-domestic buildings which were deemed unsuitable for full electrification. This reduces carbon emissions from the Orkney system to 0.5 ktCO_2 /year. The additional tidal generation both powers these electrolysers and allows a net export of 174GWh elec/year by 2050.

To support this additional electrical generation the connection between Rousay and Westray is doubled in capacity. Note that this was the only option made available to the model and does not indicate exactly what capacity was required. Investment in the electrical distribution system on land is reduced by 10% in this scenario, probably because the model was able to site additional generation closer to demands and so reduce the level of upgrading required to support electrification of heating.

When electrolysers are co-located with tidal generation then some hydrogen pipelines are required (Rousay to Westray, Eday to Westray, Hoy to Flotta) to transport hydrogen from production locations to where demand exists. This scenario has the largest volumes of hydrogen moved around the archipelago of all the scenarios explored except for those that include large volumes of hydrogen export.

Curtailment of tidal generation on Eday is reduced to 3.6% and there is no curtailment of tidal generation at the other sites.

Figure 14 – Location of new tidal and hydrogen infrastructure chosen by the model in scenario 3

4.1.6 Scenario 4: Scaled Up ITEG Technologies Uncoupled

A question which arose in discussion with consortium partners was whether it was better to site electrolysers near a source of renewable power, as in the ITEG project installation on Eday, or near a source of potential demand for the hydrogen. Scenario 4 is designed to address that question. It differs from scenario 3 only in that the generation and electrolysis do not need to be co-located in scenario 4; the model is free to choose to deploy a tidal generator alone, an electrolyser alone, or both in each location.

Tidal generation is made available for deployment in the same sizes and locations as in scenario 3. Electrolysis is offered with power rating 5MW, 20MW, 50MW and 100MW in the locations where tidal generation is available and additionally in most other analysis areas.

The assets chosen for deployment are shown in Figure 15 below. The model chooses the same tidal generation as in scenario 3 and the same electrolysis but sites three electrolysers away from the generators. These are on Flotta and in the north-west and south-west regions of Orkney Mainland, not sited on Rousay, Eday or Hoy where the tidal generators are sited. There are also differences in the timing of these deployments: Once deployed, all the tidal generators and all the electrolysers are renewed when they come to the end of their life, unlike in scenario 3, so the capacity of both tidal generation and electrolysis plant in 2050 is greater in this scenario than in scenario 3.

In this scenario only the existing hydrogen transport links between Mainland and Westray, and between Mainland and Eday, are used; there is no investment in new links. The need to build hydrogen pipelines is avoided.

When co-location of generation and electrolysis isn't forced, the electrolysers are moved to the hydrogen demands and electricity is transported. The model prefers to transport energy as electricity rather than as hydrogen. In our modelling it is able to do that using the existing electricity network; no new investment is required. One reason why that might be possible is that there is an 80% increase in consumption of electricity in domestic buildings as they are converted to electric forms of heating. This additional electricity demand – local to the renewable generation – frees up capacity on the island ring, as more renewable generation is used locally and less is exported to other islands.

For both tidal generators and electrolysers the model prefers several smaller deployments distributed around the system rather than one or two larger deployments. This conclusion was tested further by an additional run applying a small economy of scale to the capital cost of the units. Several smaller deployments were still preferred, even though there was now a small (around 1%) additional capital cost. This is likely to be because the impact on the electricity distribution system is smaller.

The consumption, and hence also production, of hydrogen is very similar in the two scenarios with only 6% of Orkney's total annual energy demand met using hydrogen by 2050.

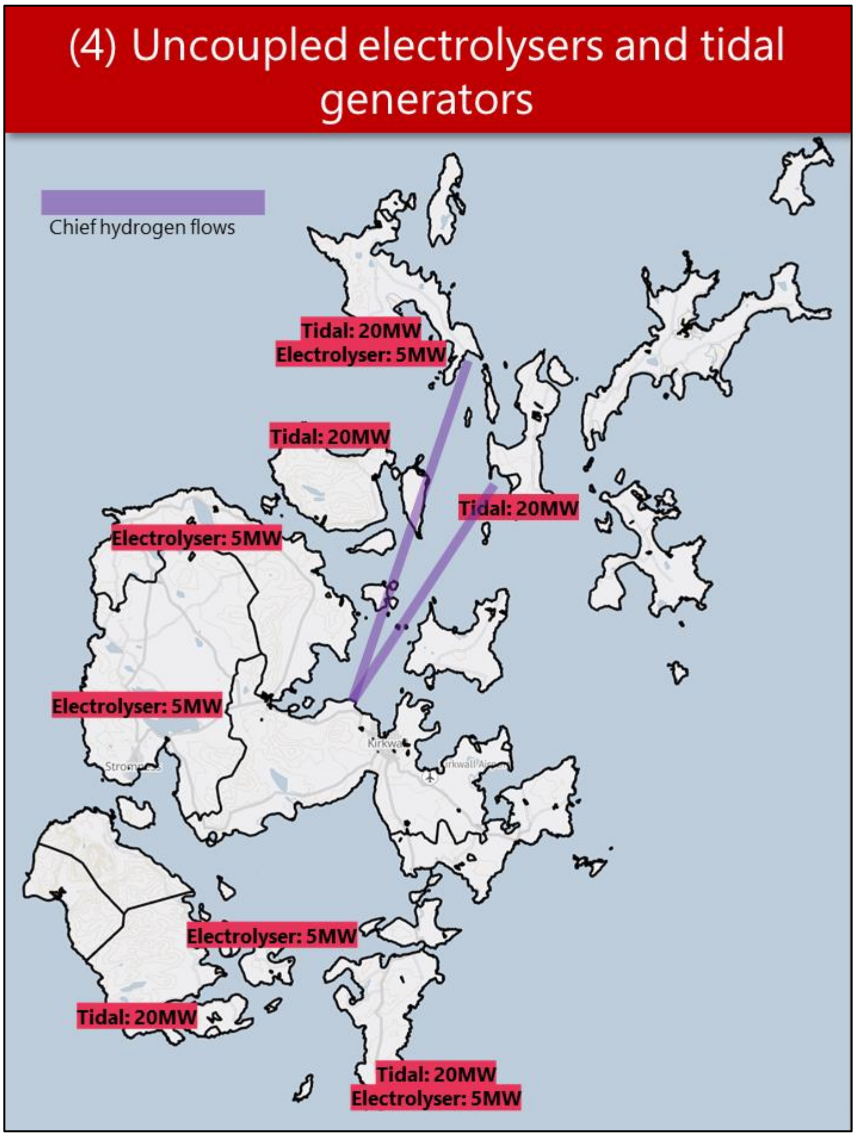

Figure 15 – Location of new tidal and hydrogen infrastructure chosen by the model in scenario 4

4.1.6.1 Electrolyser Cost Sensitivity

In discussion with consortium members, the influence of electrolyser unit capacity on electrolyser cost was raised. Upon investigation it was realised that the electrolyser cost assumptions used in the modelling had incorrectly applied the cost savings (£/MW) which result from building larger electrolysers. This resulted in smaller capacity electrolysers being modelled at incorrectly low costs in later years. The cost difference was more pronounced in later years than in earlier years. A sensitivity was performed to establish if the artificially low costs for small scale electrolysers had affected the choices made.

The increase in costs for smaller capacity electrolysers in later years resulted in a reduction in hydrogen use with more electric heat solutions chosen. Installed electrolyser capacity reduced by around 6.5MW by 2050. This had a corresponding influence on the volume of tidal generation installed with a reduction of around 17MW in 2050. Overall hydrogen production was reduced by 26% in this sensitivity with tidal generation dropping by 17%.

4.1.7 Scenario 5: Further Hydrogen System

Scenario 5 retains the options for scaled-up tidal and electrolysis deployment from Scenario 4. In addition 75kW hydrogen fuel cells are made available, capable of being run in a pure electric or combined heat and power mode. This is offered in all areas where there are buildings.

The model chooses to deploy only two additional fuel cells, a total of 0.15MW capacity out of a total of 1.275MW made available. These are only run in the winter peak periods, producing power, and the heat is rejected to atmosphere. The existing fuel cell at Kirkwall is run at higher utilisation in early years but by 2050 that too is running only at the winter peak. Carbon emissions from the system are unchanged.

There is, however, a significant reduction in the level of curtailment of tidal generation on Eday, down to 1.5% of potential production. This seems to be a consequence of the model's decision to change the location of 20MW of tidal generation deployed from Eday (in scenarios 3 and 4) to Shapinsay (in scenario 5) together with the infrastructure improvements already in place in these scenarios. This re-location results in a small improvement in the utilisation of the generated electricity helping to enable economic deployment. It is not entirely clear how this relates to the use of fuel cells at the winter peak.

It is clear that the model sees little value in shipping hydrogen rather than electricity. What benefits there are do not outweigh the energy loss in converting electricity to hydrogen and back again. In addition, with increasing electrification of heat an increasing proportion of renewable generation can be used locally such that current network constraints on generation are reduced releasing some headroom. Should the relative costs of shipping hydrogen and reinforcing electrical networks change in the favour of hydrogen then the position might change.

The locations of the hydrogen infrastructure chosen by the model in this scenario are shown in Figure 16 below.

Figure 16 – Location of hydrogen infrastructure chosen by the model in scenario 5

4.1.8 Scenario 6: Connected Hydrogen

Scenario 6 explored the implications for the Orkney energy system of gaining access to markets outside the archipelago to export hydrogen. This scenario considered an export (only) market to establish an indicative price point at which it might be viable for Orkney to install additional renewable generation and electrolyser capacity to export hydrogen. A hydrogen terminal at Flotta was modelled as the primary export location. In addition to the export market, a new 30GWh/year[46] demand was introduced to represent the annual energy consumption of Orkney's inter-island ferries. The model was given the option to meet this demand with oil or hydrogen, and selected hydrogen for the full amount in this and all subsequent scenarios.

In the modelling and analysis all energy prices were at the Orkney energy system boundary. This means that import costs quoted here include shipping to Orkney but export prices do not include cost of shipping to customers. No attempt has been made to estimate what these costs might be as part of this work.

Scenario 6 was initially modelled with a low market price for hydrogen. When market prices are below a critical threshold, deployment of ITEG technologies is generally around 95MW of tidal capacity and 40MW (electrical power) of electrolyser capacity with little change to the Orkney energy system resulting from gaining access to a hydrogen export market.

With no option to import hydrogen, seasonal storage plays a small but important part in balancing the decarbonised Orkney energy system, with around 30MWh a year of hydrogen stored in summer for use over the winter period. This storage is widely spread such that it is co-located with sources of hydrogen demand. It enables support of peak winter demand periods – typically a few hours' duration on a few of the coldest days of the year – without requiring large quantities of poorly utilised electrolyser capacity. The 30MWh per year of stored hydrogen is small compared to estimated annual hydrogen demand for buildings of 23.5GWh, with an additional annual hydrogen demand of around 30.0GWh to decarbonise the ferry fleet.

4.1.8.1 Hydrogen Market Price Sensitivity

As noted above, when hydrogen market prices are low there is little change in the energy system compared to a situation with no access to a hydrogen export market. Deployment of ITEG technologies when market prices are below this threshold cost is generally around 95MW of tidal capacity and 40MW (electrical power) of electrolyser capacity.

Once hydrogen reaches a market price of £150/MWh (approx £5/kg H_2) there is a significant deployment of additional tidal generation and electrolysis in order to service the market with an additional 500MW of tidal generation and 200MW of electrolyser capacity installed. (See Figure 17).

Locations for tidal generation and electrolysis shift from being dispersed around the islands to all being located on Hoy. This exploits the large tidal resource in the Pentland Firth[47], is close to the hydrogen export terminal at Flotta and next to the electricity interconnector to the UK mainland. A short hydrogen pipe to Flotta is built from Hoy to enable hydrogen export. Siting

[46] Low Carbon Ferries Feasibility Study, Aquatera [2016]

[47] The tidal capacity offered to the model for connection to Hoy was based on equal division of the total tidal resource in the Pentland Firth between Orkney and the UK mainland (i.e. it has been assumed in the modelling that half of the total tidal resource is available to Orkney to exploit).

tidal generation close to the UK mainland interconnector avoids constraints on the 33kV ring around Orkney so that the influence of Active Network Management is significantly reduced.

These additional deployments enable export of 650GWh (approx. 20,000 tonnes) of hydrogen alongside an additional 150GWh of electricity per year.

Tidal generation is constrained at times when peak generation coincides with very high levels of wind generation and local networks are unable to support export of all the electricity generated across Orkney.

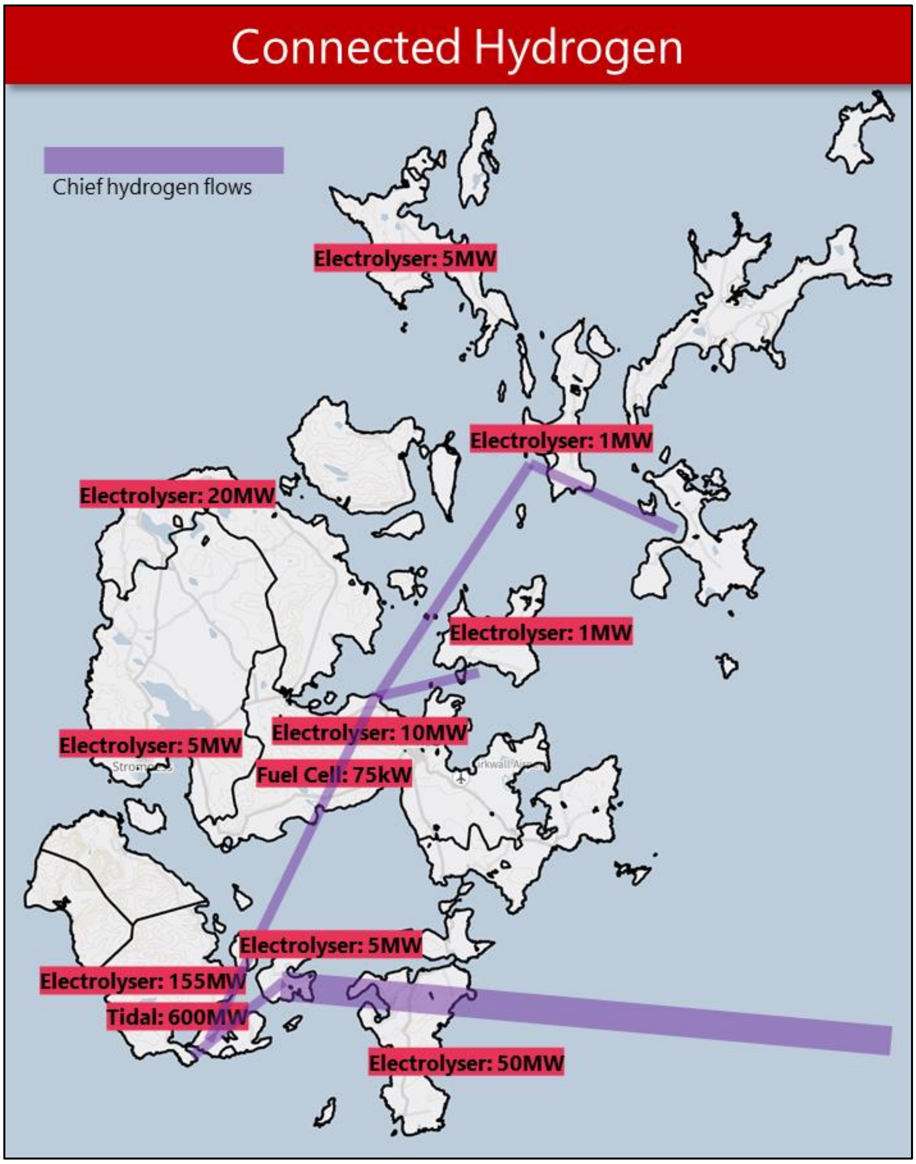

Figure 17 – Location of hydrogen infrastructure chosen by the model in scenario 6 with high hydrogen market price

The figures for hydrogen market price given here should not be taken as absolute thresholds. Deployment of large quantities of ITEG technologies in the model will be the result of a complex interaction between:

1) the absolute and relative market values of hydrogen and electricity for export from Orkney;
2) the assumed technology costs and efficiencies; and

3) the assumed costs (capital and operational) and capacities of existing energy networks, network upgrades and hydrogen shipping technologies required to get energy to the locations from which it can be exported.

The modelling suggests:

- Hydrogen production for export will only be feasible if market prices are above a critical level.
- The optimal way to produce hydrogen for export is to locate both tidal generation and electrolysers close to the export point (i.e. around Hoy / Flotta) to limit the costs associated with reinforcing the electricity networks and building hydrogen networks. This suggests tidal installation in the Pentland Firth with electrolysers on Hoy or Flotta (assuming this is the export terminal).
- Any hydrogen required locally could then be shipped to elsewhere on Orkney from this central production hub.
- If significant volumes of hydrogen are to be exported then it is likely that some hydrogen pipelines will need to be installed between the point of production and the export terminal. Alternatively, additional electricity network capacity might be required such that electrolysis can be located at the export point.

4.1.9 Scenario 7: Competitive Hydrogen

In scenario 7 an option to import hydrogen was added, to explore how this might influence Orkney's energy system choices and opportunities. The hydrogen terminal at Flotta was modelled as the primary import location.

With access to a hydrogen import market, electrolyser capacity deployed on Orkney drops to around half that seen when all hydrogen must be produced locally. Imported hydrogen makes up more than half of total demand.

The money saved by importing cheap hydrogen is partly used to install cheaper to operate, direct electric heating systems – rather than ground source heat pumps – in domestic properties. The direct electric heating systems have a higher peak power output so installation is restricted to a level that avoids additional electricity network reinforcement.

When import of hydrogen to Orkney is enabled in the model no seasonal storage is used as it is more cost-effective to import hydrogen when required to meet peak demand periods. Short-term storage is used to ensure security of supply and any delays during shipping hydrogen from the import hub to demand locations.

The level of tidal generation capacity deployed is not significantly changed in this scenario.

4.1.9.1 Hydrogen Market Price Sensitivity

The relative quantities of imported and Orkney-produced hydrogen change with market price. When hydrogen imports are enabled in the model at in import price of £75/MWh (approx £2.50/kg H_2) or less then nearly all required hydrogen is imported and there is limited deployment of local electrolysis (around 4MW electric capacity). This rises to around 24MW total capacity with a hydrogen price of £125/MWh (approx £4.15/kg H_2) – little over half the level of electrolysis required if hydrogen cannot be imported. The influence of hydrogen market price on the relative quantities of imported and on-Orkney produced hydrogen are shown in Figure 18.

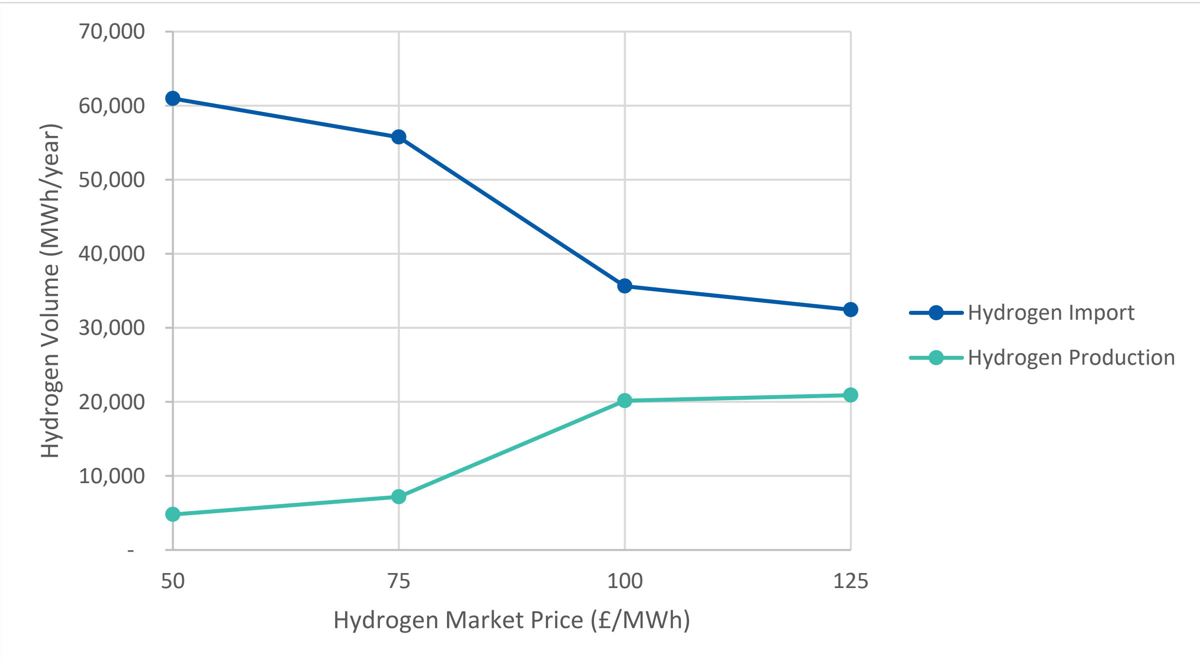

Figure 18 – Influence of hydrogen market price on hydrogen imports and local hydrogen production

As the modelled hydrogen price increases the total volume used decreases. This is due to alternative decarbonisation options becoming more cost effective compared to using hydrogen. Deployment of hydrogen for heat in commercial and industrial buildings increases if it is available at very low import prices. A similar influence is seen on domestic heating to a limited extent.

The level of tidal generation deployed appears insensitive to both the availability of a hydrogen import option and the price of imported hydrogen.

The modelling suggests that if Hydrogen is available from markets at low prices it could be cheaper to import than to produce locally.

4.1.9.2 Electricity Market Price Sensitivity

The influence on the cost-optimal zero carbon energy system of electricity market price (the cost to import electricity to Orkney from the UK mainland) was also explored. This sensitivity included access to import and export markets for hydrogen. Hydrogen market price was set at £125/MWh (below the threshold that caused large scale production for export in scenarios 6 and 7). This was done to ensure that model results were not skewed by participation in a highly speculative hydrogen market (perhaps by importing electricity to produce hydrogen for export) but were focussed on finding the most cost-effective solution for Orkney.

The average annual electricity market price used in all other scenarios[48] is shown in Figure 19. The influence of scaling these prices by 0.8 and 1.2 was tested.

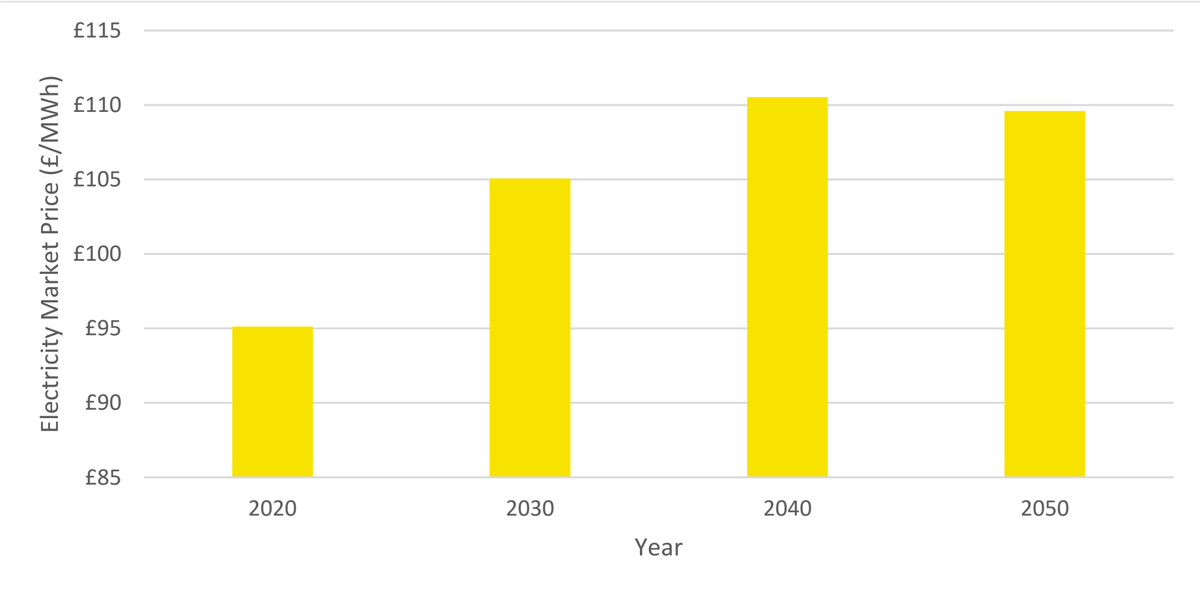

Figure 19 – Average annual price to import electricity to Orkney from the UK mainland

Increasing electricity market price results in higher levels of deployment of tidal generation and electrolysers as shown in Figure 20. Higher electricity prices result in increased import of

[48] Within the EnergyPath networks model electricity price varies to reflect real world changes within the day such as high market prices at times of peak demand and lower prices overnight. Values shown here are average daily values for different years.

hydrogen (Figure 21) for use in heating buildings as shown by the changes in building demands in Figure 22.

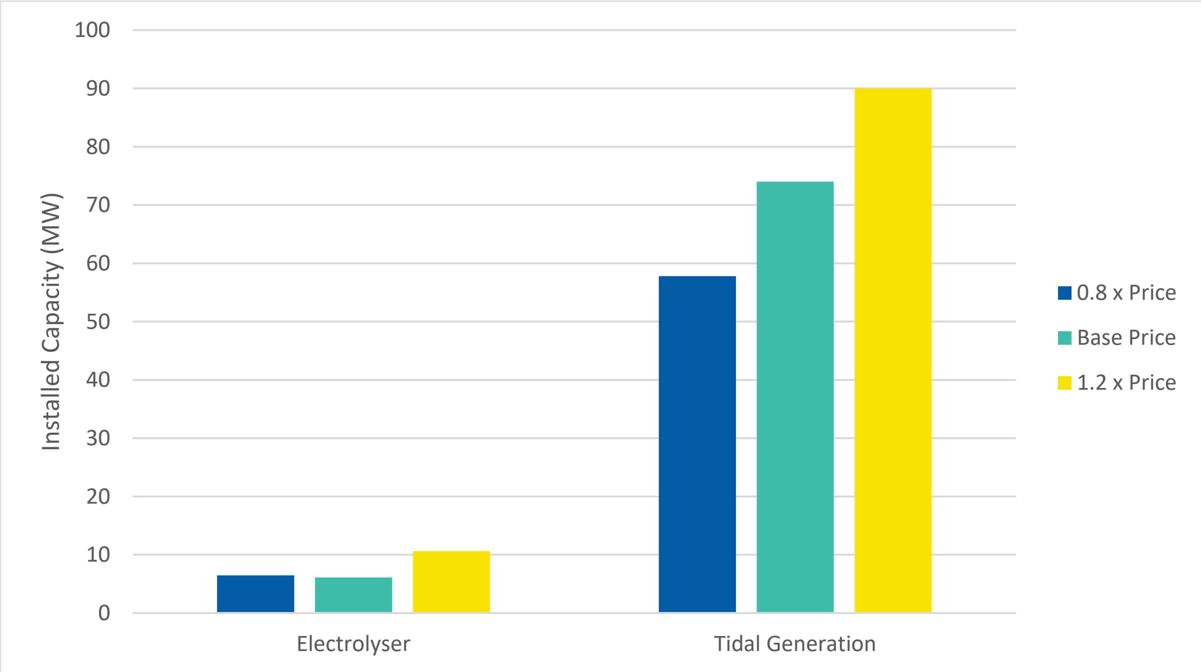

Figure 20 – Modelled change in installed electrolyser and tidal generation capacity with electricty market price

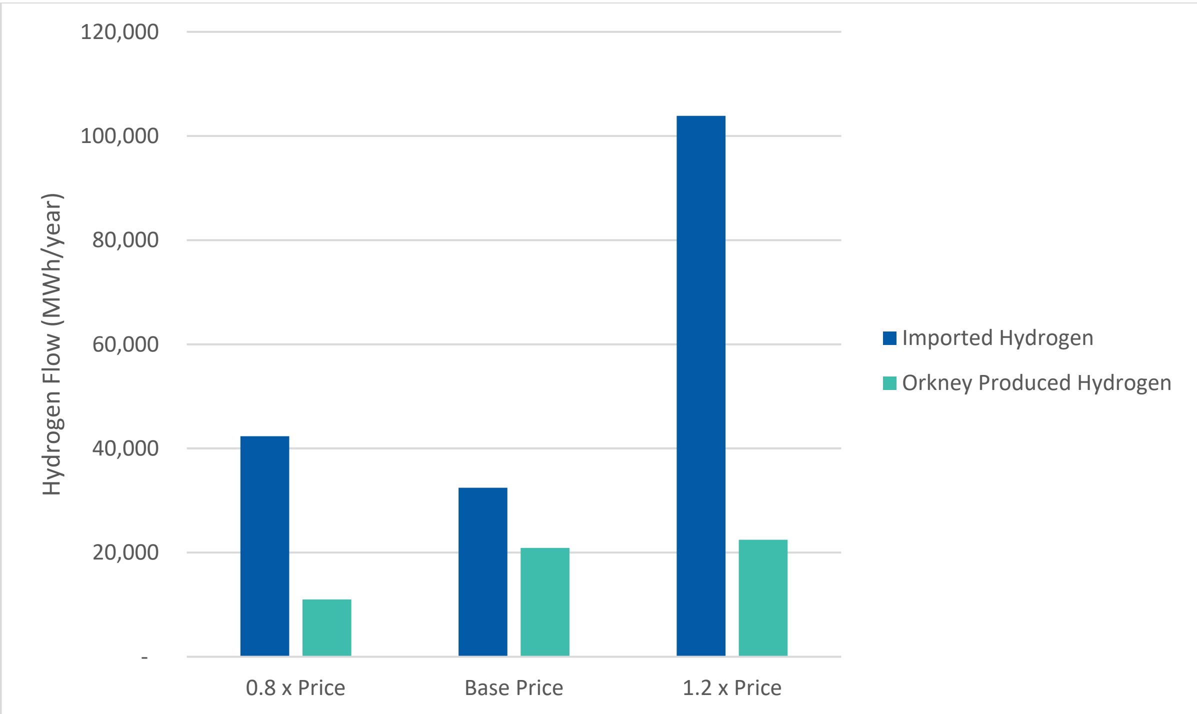

Figure 21 – Modelled annual hydrogen import and on-Orkney production for different electricity market prices.

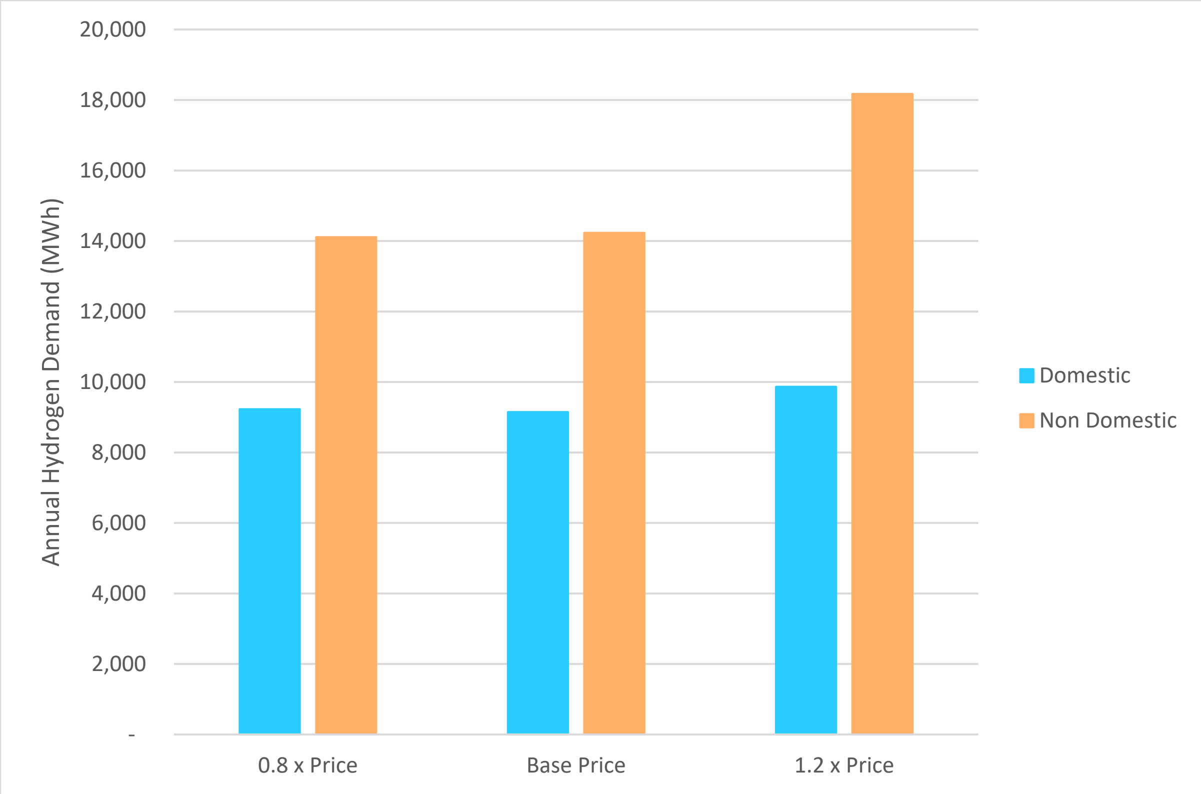

Figure 22 – Modelled change in building hydrogen demand with electricity market price

As expected with a cost-optimising model, the level of electricity import reduces with increasing electricity cost whilst electricity exports increase as shown in Figure 23 (although the level of increase is dependent on the point in the cost range tested).

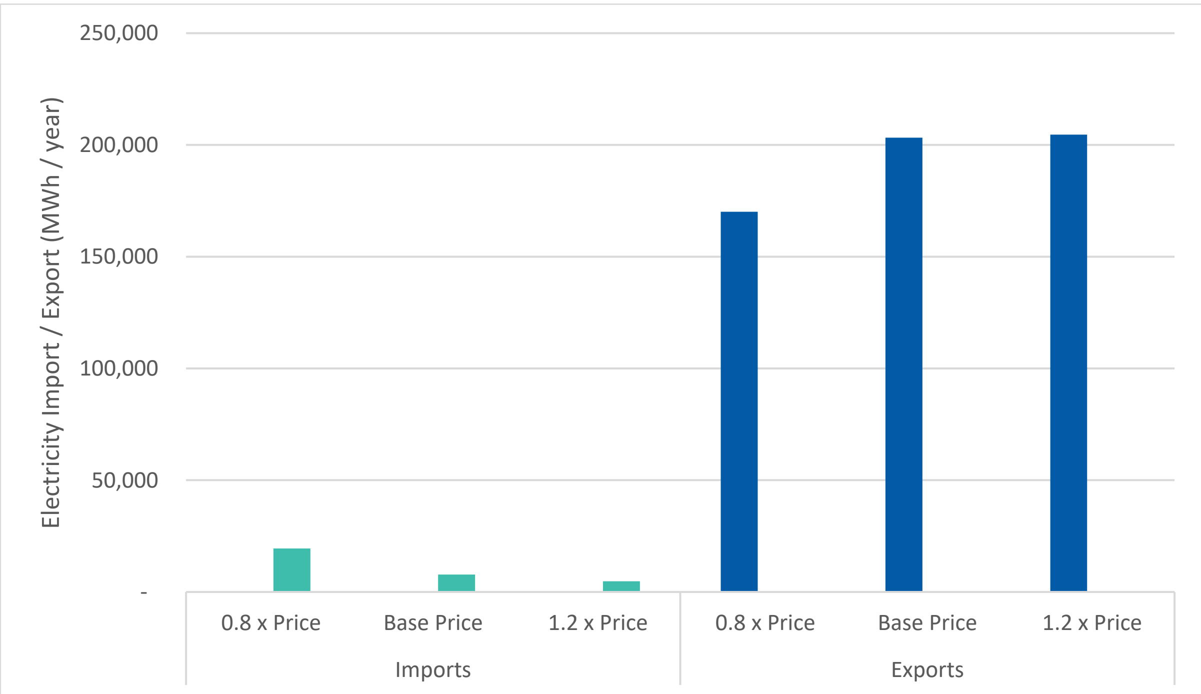

Figure 23 – Modelled change in electricity import and export from Orkeny with changing electricity market price

The role for ITEG technologies on Orkney is likely to increase with increasing electricity market prices.

Changes to the market price of electricity do not fundamentally change the cost-optimised, net zero Orkney energy system. Whilst there are some changes to the precise levels of deployment of different technologies, these are generally in proportion to the change in electricity price suggesting that starting to implement the change required to meet net zero can be done at relatively low risk with little chance of stranded assets.

4.1.10 Scenario 8: Electricity Focus

Based on scenario 7, scenario 8 adds a costed option to upgrade the interconnector to the UK mainland in line with SSEN proposals, with an additional 220MW of capacity at a total cost of £260m. The scenario also includes options for deployment of wind generation to enable the threshold deployment level (135MW of new capacity) required by Ofgem[49] for construction of the interconnector upgrade to be met.

Hydrogen market price was set at £125/MWh (below the threshold that caused large scale production for export in scenarios 6 and 7). This was done to ensure that model results were not skewed by participation in a highly speculative hydrogen market but were focussed on finding the most cost effective solution for Orkney.

Under this scenario the interconnector upgrade is built alongside increased renewable generation (400MW of tidal and140MW of wind). These are modelled as producing additional annual generation of 1,600GWh from tidal and 560GWh from wind from 2030 onwards (giving annual totals of 1,900GWh from tidal and 800GWh from wind).

Tidal generation is located around Hoy to allow electricity export directly on the new interconnector. Wind generation is dispersed but mainly located on South Ronaldsay, Mainland Central, Mainland North, Sanday and Westray.

Electrolysers are installed on Hoy, South Ronaldsay and Mainland North as well as in Stromness. With a total installed capacity of 220MW (electrical power), these are modelled to produce as much as 280GWh of hydrogen a year.

In order to exploit this increased renewable generation some HV substation reinforcement is seen on Hoy, Rousay, Westray and Mainland Central. Depending on the precise locations of the new generation, additional HV feeder capacity may also be required. Modelling suggests this might be required on Hoy, South Ronaldsay and Westray.

Since import of hydrogen to Orkney is enabled in this scenario, no seasonal storage is used as it is more cost-effective to import hydrogen when required to meet peak demand periods. Short-term storage is used to ensure security of supply, as hydrogen has to be shipped from the import hub to demand locations.

In general, the additional electricity generated is exported (around 60% of total generation) until network constraints are reached. At these times electrolysers are used to produce hydrogen (of which 194GWh is exported). The increase in renewable generation is sufficient to mean that electricity imports to Orkney are modelled as close to zero.

The level of electrolyser deployment is insufficient to use all the electricity generated that is not exported at times of peak renewable production. At these times there is still some curtailment, as generation exceeds the sum of demand (from all sources) and the total that can be exported. This suggests that the cost-optimal choice is to accept some curtailment at times of peak generation, with electrolysers and associated hydrogen storage sized to be able to use or export all generated energy at other times (assuming market access for electricity and hydrogen).

[49] https://www.ofgem.gov.uk/publications/ofgem-gives-go-ahead-orkney-transmission-link-subject-conditions

There is a slight switch (compared to scenario 7) to increased electrification of heat rather than using hydrogen boilers. The reductions in the number of buildings using hydrogen boilers are 1% for domestic and 2% for non-domestic buildings. Buildings that switch to electric heat in scenario 8 are located where the additional wind generation is installed.

4.1.10.1 Hydrogen Market Price Sensitivity

As part of this scenario, a sensitivity was run with the hydrogen market price set at £150/MWh (approx £5/kg H_2, the threshold at which large amounts of hydrogen was produced for export in Scenario 6). When the interconnector upgrade is available this hydrogen market price is no longer sufficient to justify a large increase in deployment of ITEG technologies to produce hydrogen for export. At this price the relative benefits of exporting electricity against exporting hydrogen are such that electricity exports are preferred over hydrogen exports. Electricity exports are similar to those seen with a lower hydrogen market price. In contrast hydrogen exports are only 39% of those seen at this hydrogen market price when the electricity interconnector upgrade was not available.

4.1.10.2 Conclusions Regarding Electricity Interconnector Upgrade

A number of important conclusions can be drawn from Scenario 8 about the benefits of upgrading the electricity interconnector to the UK mainland. These conclusions, and the evidence of the detailed modelling behind them, should strengthen the case for early investment in this interconnector – both as part of a net zero strategy for Orkney and as part of the Scottish Government's plans for potential hydrogen hubs.

Additional renewable generation enabled by construction of the electricity connector upgrade is a mixture of both tidal and wind generation. This is due to the value to the energy system of having a more diversified generation profile compared to installing only one technology.

Building the electricity interconnector upgrade unlocks significant potential for the Orkney energy system allowing:

- a significant increase in cost-effective wind and tidal generation to a level that makes Orkney almost self-sufficient in a decarbonised future, needing to import energy on only limited occasions through the year;
- export of significant quantities of both wind and tidal generation with possibilities for hydrogen export if markets can be accessed at a competitive price; and
- opportunities to maximise the benefits of renewable generation through hydrogen production when generation is in excess of the combination of local demand and the capacity of the new interconnector.

Investment in the electricity interconnector upgrade, regardless of other factors, would therefore be a "no-regrets" decision which could be implemented immediately without pre-conditions, and there is a clear case for change in the present regulatory constraints.

Even with the new interconnector, the cost-optimal level of renewable generation deployment results in some curtailment at times of peak generation, as this is outweighed by benefits at other times.

The new interconnector results in reduced desire to produce hydrogen for export with a preference to export renewable generation as electricity rather than convert to hydrogen.

There is further discussion of the interconnector upgrade in relation to the proposed West of Orkney Windfarm at section 5.3.

4.2 Headline Comparison of Scenario Results

Detailed results for each of the nine scenarios individually are set out in Appendix A. Headline points of comparison between scenarios are set out in this section 4.2.

4.2.1 Carbon Emissions

In-scope carbon emissions include those related to energy use in domestic and non-domestic buildings (mainly from oil) and those linked to electricity imported onto Orkney. From scenario 6 onwards oil use from the ferry fleet is also included. Decarbonisation of other transport modes such as HGVs, buses and the maritime fleet was not included in the modelling.

Figure 24 shows the emissions reductions over the period to 2050 for each of the nine scenarios.

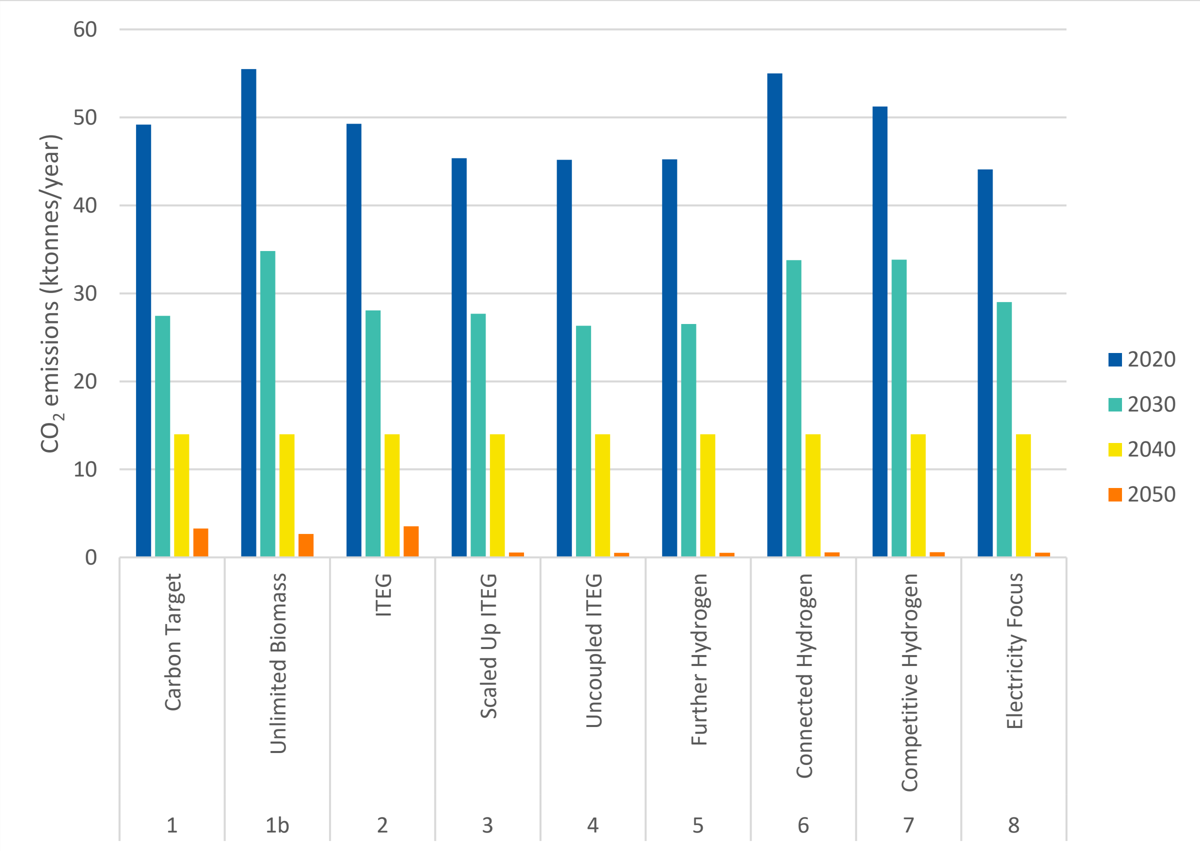

Figure 24 – Carbon emissions by scenario

All scenarios meet the intermediate 2040 target (set in the model on the way to net-zero in 2045), thereby avoiding carbon penalties for this period. The largest component of emissions reduction is achieved in the 2020s, in all scenarios except 7, where the largest change occurs a decade later. This assumes immediate high rates of low carbon technology deployment, with building heating systems changed in the next ten years.

Adding the ITEG technologies (scenario 2) replaces some of the imported electricity from scenario 1 with lower carbon energy sources. However, the greater demands on the power network then reduce the potential for some non-domestic heat to be electrified. The resulting oil demand in scenario 2 is therefore greater than in scenario 1, leading to slightly higher carbon emissions in 2050. With the increased availability of lower carbon electricity seen with the scale-up of ITEG technologies in scenario 3, a stronger economic case for reinforcement of the electricity grid emerges. This allows oil to be almost completely removed from scenario 3 onwards and allows tidal generation to provide enough energy to export electricity, in contrast to the import requirements in other scenarios. This change results in significantly lower carbon emissions in scenarios incorporating the scaled-up ITEG technologies.

Offering further electrolysis options (scenario 4) leads to a very small reduction in the remaining 2050 carbon emissions. Having unlimited biomass available (scenario 1b) also leads to a relatively low level of 2050 emissions.

By 2040, the vast majority of remaining emissions are from non-domestic buildings across all scenarios (see Figure 25). Some emissions remain in non-domestic buildings because of the more limited options to decarbonise them and the constraints that apply to those options, discussed further later in this section.

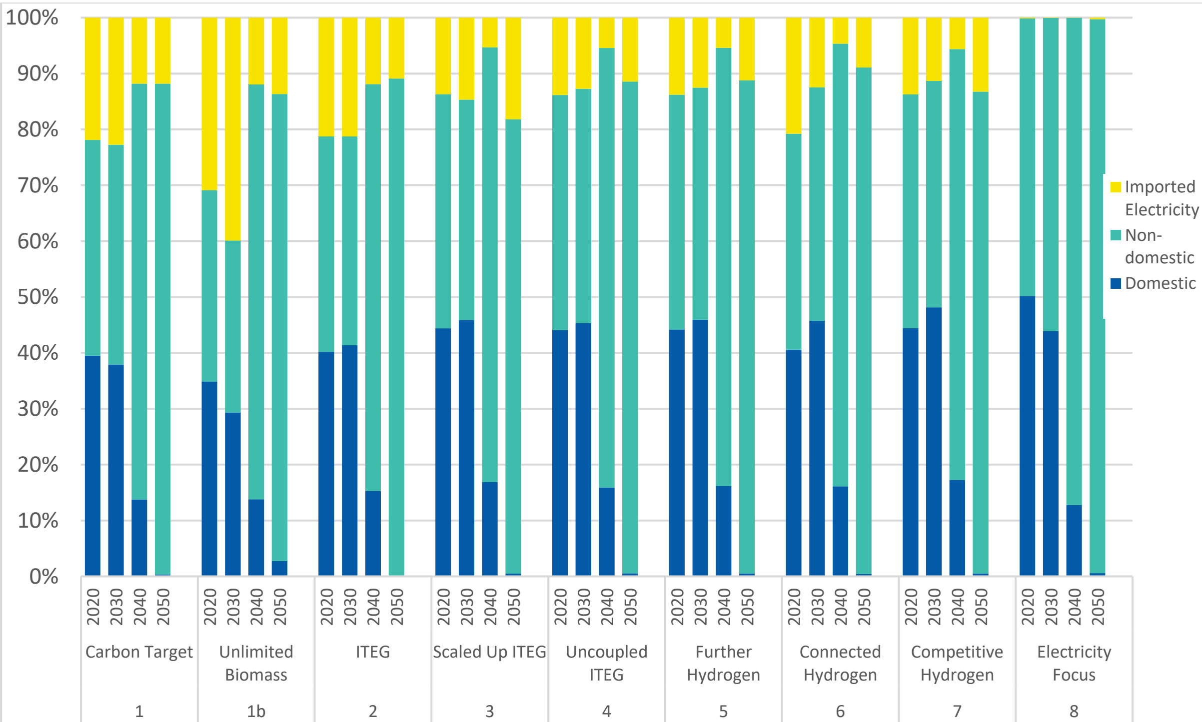

Figure 25 – Breakdown of carbon emission by scenario

4.2.2 Domestic Buildings

Figure 26 shows the modelled initial primary heating systems in domestic buildings in Orkney alongside the resulting domestic primary heating systems[50] by 2050 in each scenario. Almost 60% of domestic buildings modelled start with oil systems, with the rest mainly electric resistive heating with a smaller number of heat pumps.

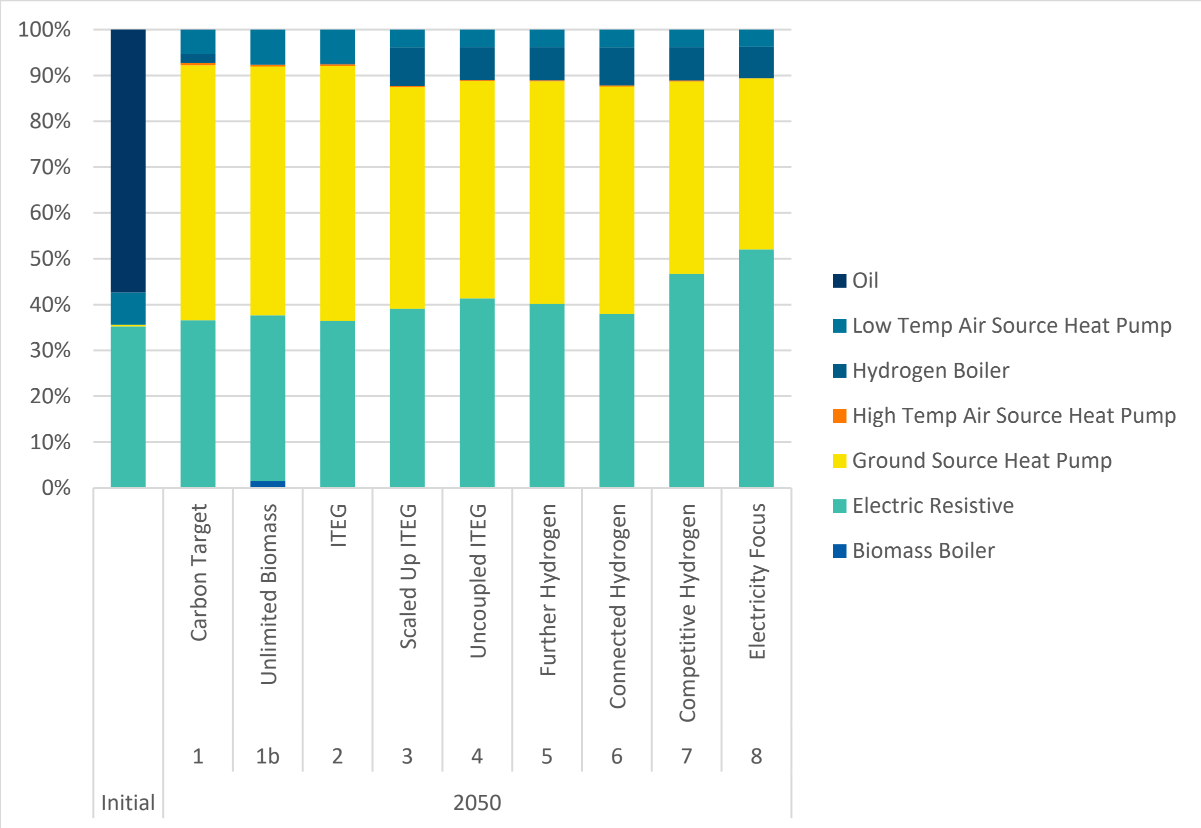

Figure 26 – Initial and 2050 primary domestic heating systems

By 2050, the predominant domestic heating system is ground source heat pumps across all but two scenarios (7 and 8). Although these have a greater capital cost than air source heat pumps, they operate at a greater efficiency and so have a lower ongoing running cost and reduce the electricity demand (with the potential to reduce peak load reinforcement requirements). They tend to be more cost effective where the building demands are larger, but they are limited to buildings where there is sufficient space and access to install a ground loop. The Orkney building stock seems well suited to take advantage of this, having many hard to heat homes, of which a high proportion are detached. In scenarios 7 and 8, the electric resistive forms the predominant domestic heating system.

Oil heating is retained in a negligible amount of the housing stock in scenario 1 and eliminated entirely from domestic heating in all other scenarios. With the inclusion of scaled-up ITEG technologies (scenario 3 onwards), hydrogen boilers are shown to play a potential role in almost 10% of the domestic building stock. A small number of biomass heating systems are seen in scenario 1b where unlimited biomass is available.

[50] As chosen as lowest whole system cost whilst minimising carbon

District heating is not selected by the model in any of the main scenarios (options to provide heat from facilities powered by hydrogen boilers and large scale heat pumps were offered). This is due to the relatively high costs of building heat networks which are found to be more expensive than the alternative of electrification of heat (using heat pumps and some direct electric heat) alongside some use of hydrogen in individual boilers. If a local source of hydrogen is not available then district heating using large scale heat pumps is a possible, but more expensive, option for central Kirkwall to reduce emissions from domestic and non-domestic buildings with high heat demands that are not suited to electrification options.

A range of measures is also used to reduce the energy demands of a property. These measures are grouped into 'insulation packages', with the measures included in each package being dependent on the building to which they are being applied. Figure 27 shows the modelled use of insulation packages by 2050 in each scenario. In all scenarios the majority of buildings have a high level of additional insulation measures applied, giving a deep retrofit. The optimisation model sees value in these measures for three reasons – firstly they are likely to reduce building carbon emissions (where the energy used in a property is not zero carbon), secondly they reduce the peak load and hence the impact on the electricity network where electric heating is used, and thirdly they might be required in order to allow use of heat pumps which do not have the same ability to deliver heat at high power as fossil fuel boilers. There can also be a secondary indirect effect for non-electric heating systems, where fuel savings can be used in non-domestic applications elsewhere in the system which would otherwise be more difficult or expensive to electrify.

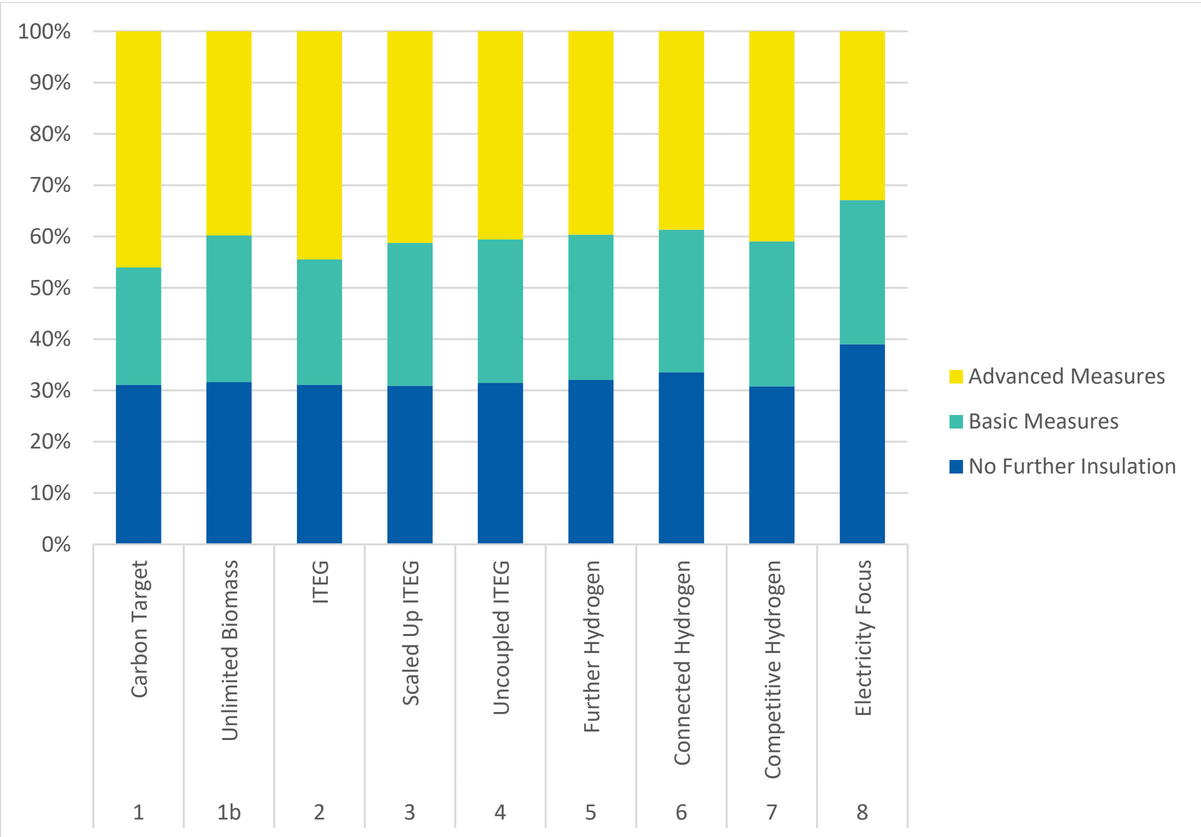

Figure 27 – 2050 domestic insulation

It is notable that more insulation is required when neither biomass nor hydrogen is available at scale (scenarios 1 and 2). Without these lower[51] carbon energy sources, which do not create extra load on the electricity network, the model shows it to be more cost effective to insulate further than it does in the scenarios in which they are available. Scenario 1b sees the greatest number of basic insulation measures, but comparatively few advanced measures, with the increased biomass availability resulting in the absence of non-domestic hydrogen boilers.

4.2.3 Non-Domestic Buildings

Non-domestic buildings have options to decarbonise through switching to electric heat solutions or hydrogen boilers. Where appropriate the options include fabric retrofit to improve thermal efficiency and reduce both annual and peak heat demands.

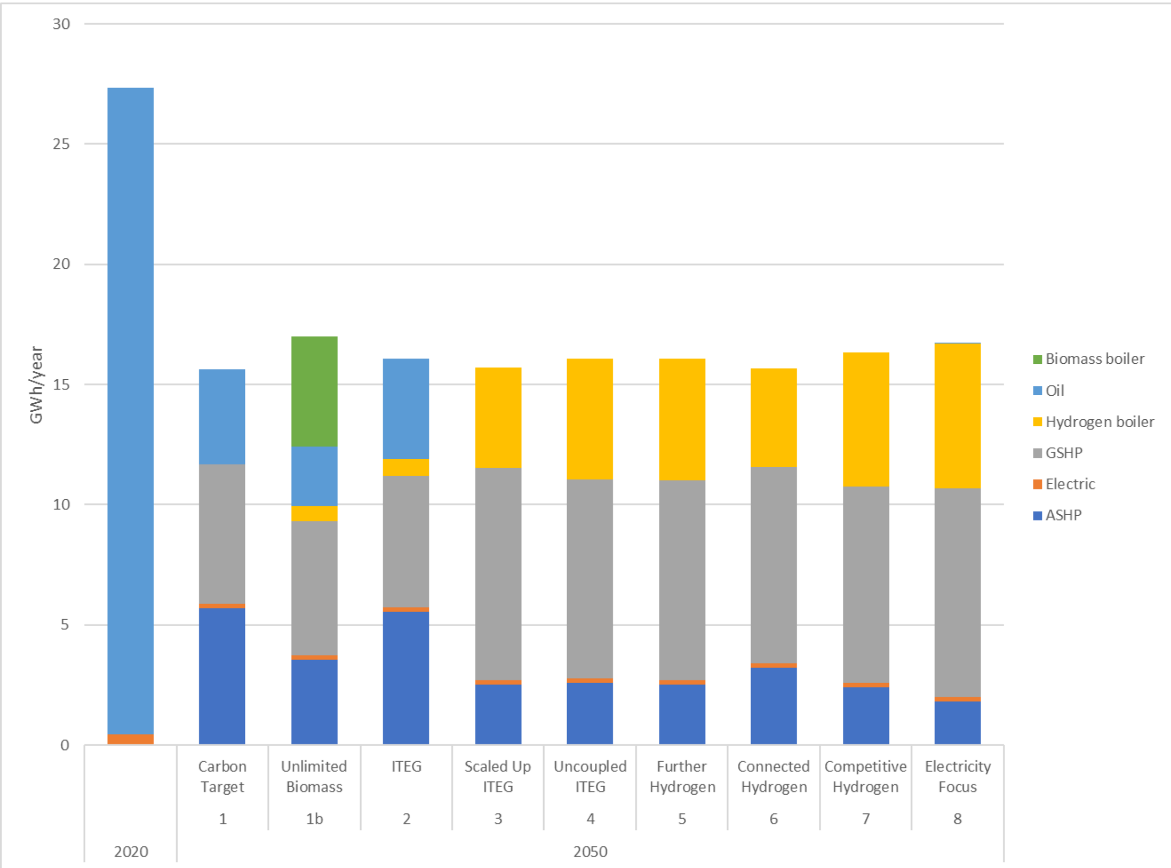

Figure 28 – 2050 non-domestic building demand by heating system

Figure 28 shows that from Scenario 2 onwards the proportion of non-domestic energy provided by all electric heating options combined is fairly similar across the scenarios. As for domestic buildings, more efficient ground source heat pumps are favoured over cheaper air source heat pumps in most scenarios. In scenarios where some hydrogen is available, this displaces a proportion of demand for oil in non-domestic buildings, with no oil systems left from scenario 3 onwards when sufficient hydrogen can be produced. The biggest difference in electrical energy

[51] The biomass needs to have been sourced and managed in specific ways to be low carbon, such as the use of agricultural wastes, residues, or sustainable woodland stocks. A detailed discussion is available at https://www.theccc.org.uk/wp-content/uploads/2018/11/Biomass-in-a-low-carbon-economy-CCC-2018.pdf

use is seen in scenario 1b, where the increased biomass results in reduced demand from ASHPs and, to a lesser extent, reduced oil consumption.

The non-domestic buildings remaining on oil represent the bulk of the remaining emissions in early scenarios as described in section 4.2.1.

4.2.4 Primary Energy

Figure 29 shows the supply of primary energy by vector in the energy system in 2050. (Note the different scale for scenario 8). The hydrogen and electricity bars represent net import to Orkney (positive values) or net export from Orkney (negative values).

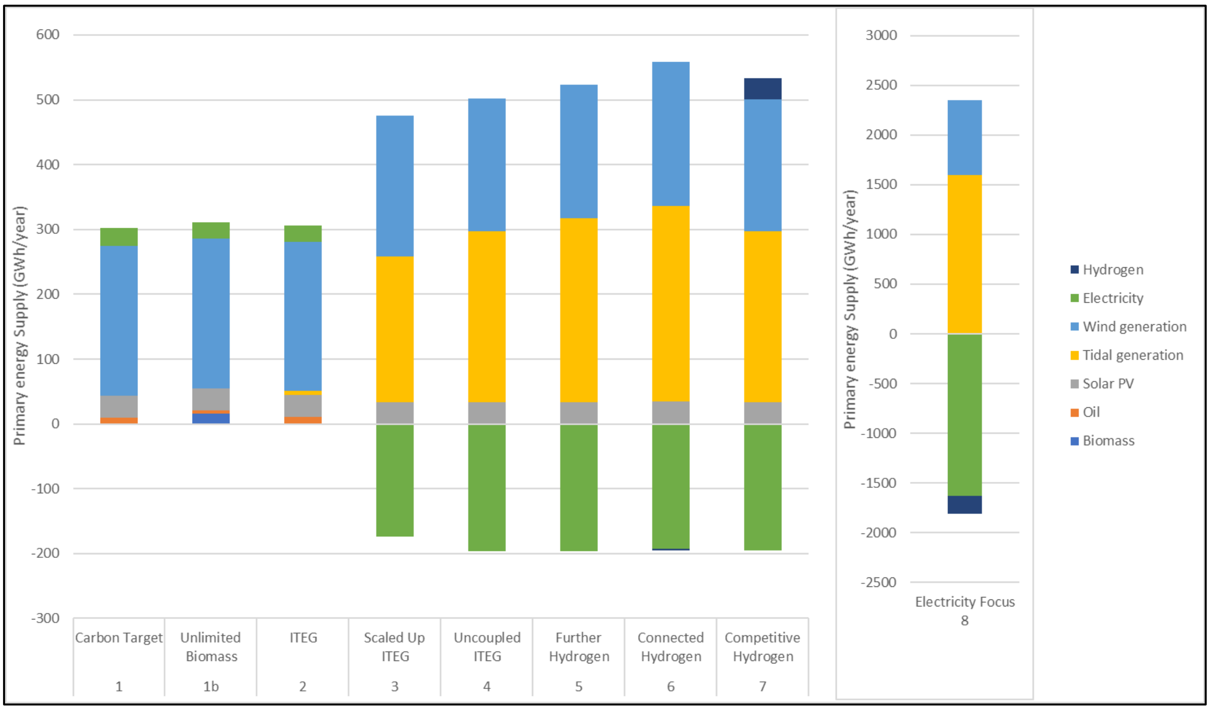

Figure 29 – Primary Energy Sources in 2050

In scenarios 1 to 3 the majority of energy is from wind generation, followed by solar PV and then some net electricity imports from the UK mainland, with a little residual oil. Although Orkney currently produces more electricity than it consumes (averaged over the year), by 2050 electrification contributes to decarbonisation in all the scenarios modelled, increasing annual demand such that there is a need to import electricity in the model. By 2050 all grid electricity is assumed to be virtually zero carbon and so these imports are not higher carbon than the local generation options.

With increased local electricity demand an alternative option might be to develop more wind farms on and around Orkney. However, only scenario 8 includes options for increased local wind generation, reflecting the current situation in which new wind generation projects are hard to justify due to the current network constraints and the effects of the Active Network Management system.

Scenarios from 3 onwards show a role for scaled up tidal generation and increased use of electrolysers, with significant net export of electricity.

Some of the electricity from the sources shown in Figure 29 is used in the production of hydrogen through electrolysis. Figure 30 (overleaf) shows a modest 20-30 GWh/year of hydrogen produced and used in scenarios 3 to 5 in 2050. This hydrogen is mainly used in non-domestic buildings.

The energy demand for propulsion of ferries was added to the model from scenario 6 onwards, along with the opportunity to switch this demand from oil to hydrogen. It can be seen in Figure 30 that this option is selected in all cases when available (and therefore there is no corresponding oil demand in Figure 29 as this is immediately switched to hydrogen).

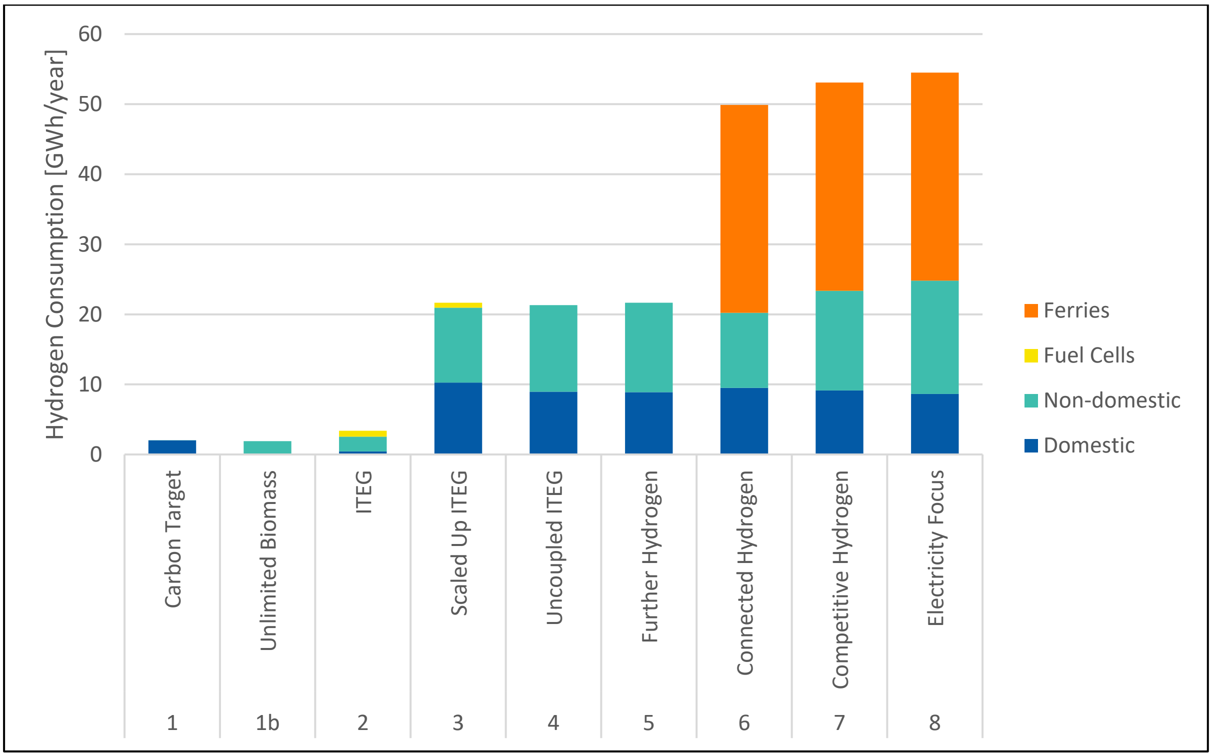

Figure 30 – Hydrogen consumption in 2050

Note also that in Figure 29 the results for scenario 6 are presented at a hydrogen market price below the threshold at which significant export of hydrogen occurs. This approach is consistent with presentation elsewhere in this report (see section 4.1.8). The sensitivity analysis showed that, above this threshold, up to 650GWh (approx. 20,000 tonnes) of hydrogen might be exported.

Figure 31 shows the modelled level of curtailment for each scenario in 2050. This is the total curtailed energy from wind and tidal combined. The proportion of generation curtailed has a maximum value of around 15% of all renewable generation when the current network constraints are considered. Curtailment is still around 8% in Scenario 8 after the electricity link to the UK mainland has been constructed. See section 4.1.10 for a discussion of this scenario.

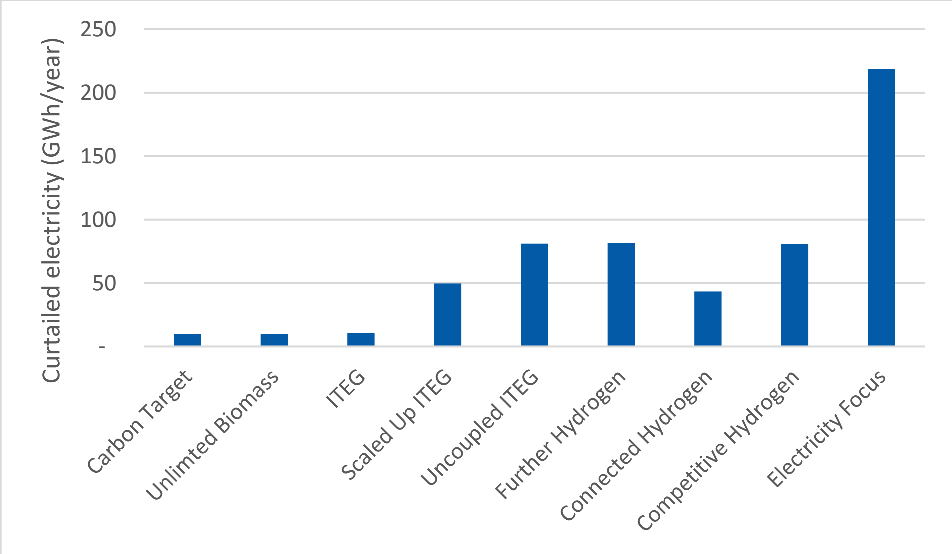

Figure 31 – Modelled annual electricity curtailment in 2050

4.2.5 Hydrogen Infrastructure

The following figures summarise the hydrogen related infrastructure installed under each scenario, with hydrogen distribution shown in Figure 32, and tidal and hydrogen technologies in Figure 33. (Note the different scale for scenario 8).

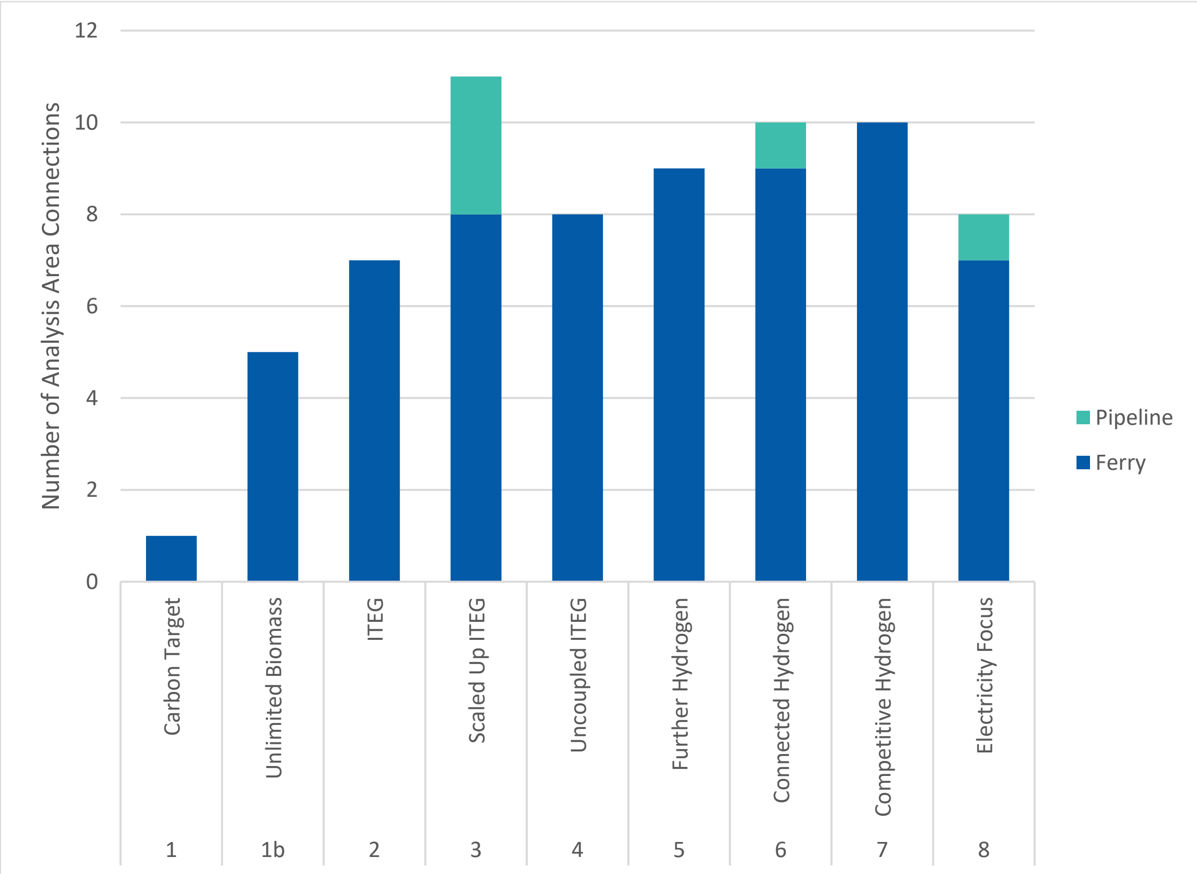

Figure 32 – Hydrogen distribution in 2050

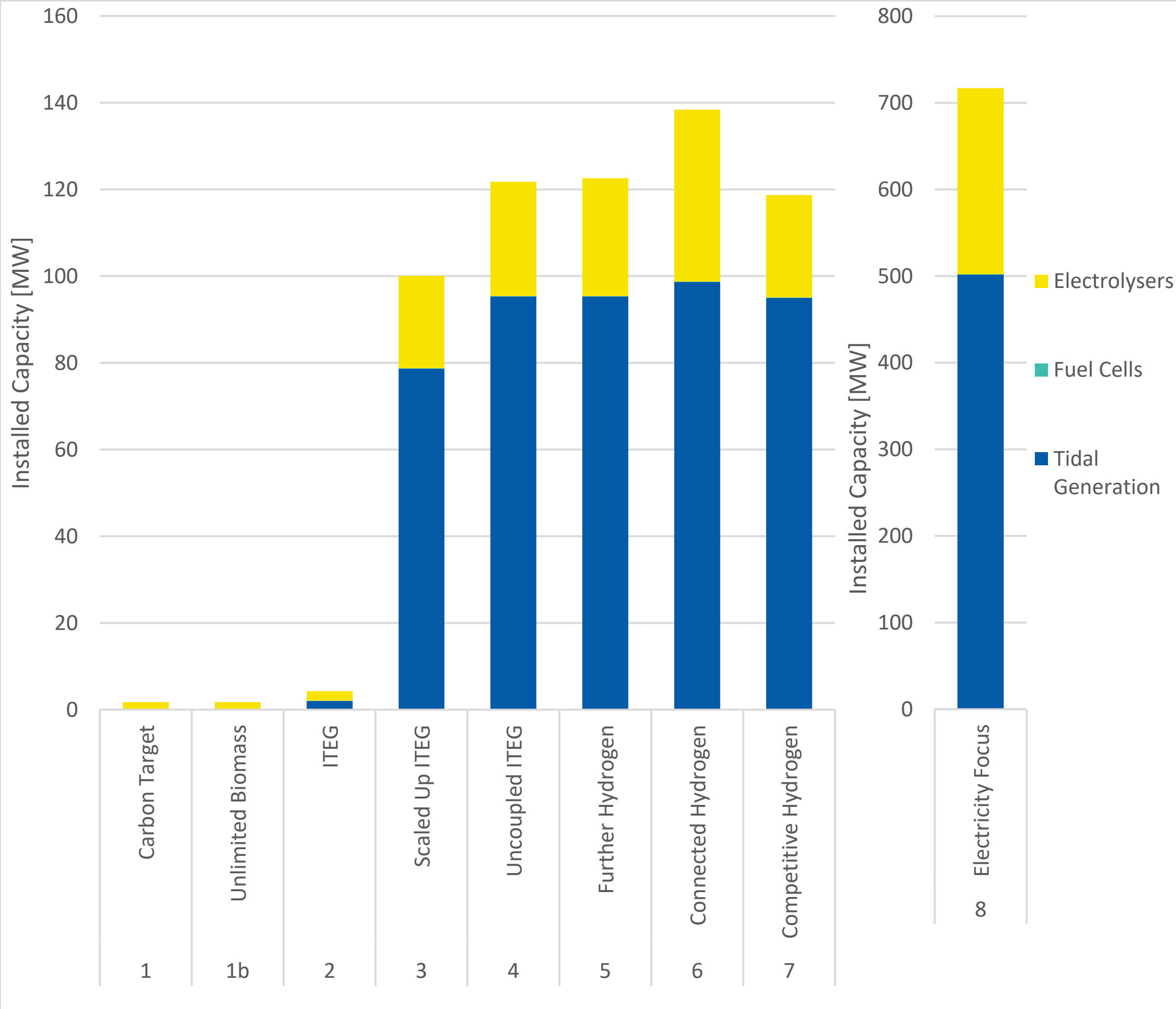

Figure 33 – Installed capacity of hydrogen and tidal technologies in 2050

Scenario 1b sees five additional ferry routes utilised for hydrogen distribution, required as a result of the increase in non-domestic demand compared to scenario 1. Scenario 2 sees the same additional connections, except at Mainland Central, where hydrogen distribution is to (rather than from) Eday and (in some seasons) Shapinsay. A new connection to Hoy is also used to support additional hydrogen demand.

The significant increase in both domestic and non-domestic hydrogen demand seen in scenario 3 results in an increased number of connections and, notably, investment in pipeline infrastructure. Only four of the connections are common to scenarios 2 and 3, again illustrating the differing distribution requirements resulting from varying levels of hydrogen use. Allowing electrolysers to be sited, as in scenario 4, near centres of demand rather than close to electricity generators prevented pipelines appearing in the hydrogen distribution network.

In scenario 2, the transport of hydrogen between electrolysers and hydrogen demand locations is a limiting factor on further use of hydrogen. In scenario 3, the modelling allowed costed build of as much hydrogen transport as required to enable scaled up deployment of hydrogen. In practice this will require resolution of regulatory issues around transportation by sea and/or investment in undersea pipelines. The majority of hydrogen transport in scenario 2 occurs between Eday and Orkney Mainland, with 3.4GWh of hydrogen shipped annually. While this reduces to 2.6GWh in scenario 3, this forms a small part of the total hydrogen movement observed, with significantly more hydrogen transport between other locations. Eday and Westray see a total of 8.8GWh each year by 2050, and the annual shipping across the Orkney system is an order of magnitude greater than in scenario 2.

Seasonal hydrogen storage is another area worthy of consideration. In the first three scenarios it is used very little, with never more than 4MWh/year being stored (see Figure 34). Once other assets, especially the electrolysers, are available at the optimal size for the system, the role for hydrogen storage increases significantly, particularly when the ITEG technologies are uncoupled from scenario 4 onwards. With the ability to export hydrogen in scenario 6, the value of storage to provide for demand within the Orkney energy system is lessened slightly. With the import option in scenario 7 the benefit of seasonal storage of hydrogen is removed altogether, with the model instead choosing to export and import as required.

Even where seasonal hydrogen storage is used at its maximum, the 55MWh/year stored represents less than 0.5% of the total hydrogen used for heating purposes (21.7GWh/year) in this scenario. Compared to tidal generation capacity, the total 55MWh/year seasonal hydrogen storage is only of the order of 1MWh/week, or the equivalent of the output from a single 2MW tidal turbine for only 5 minutes a day.

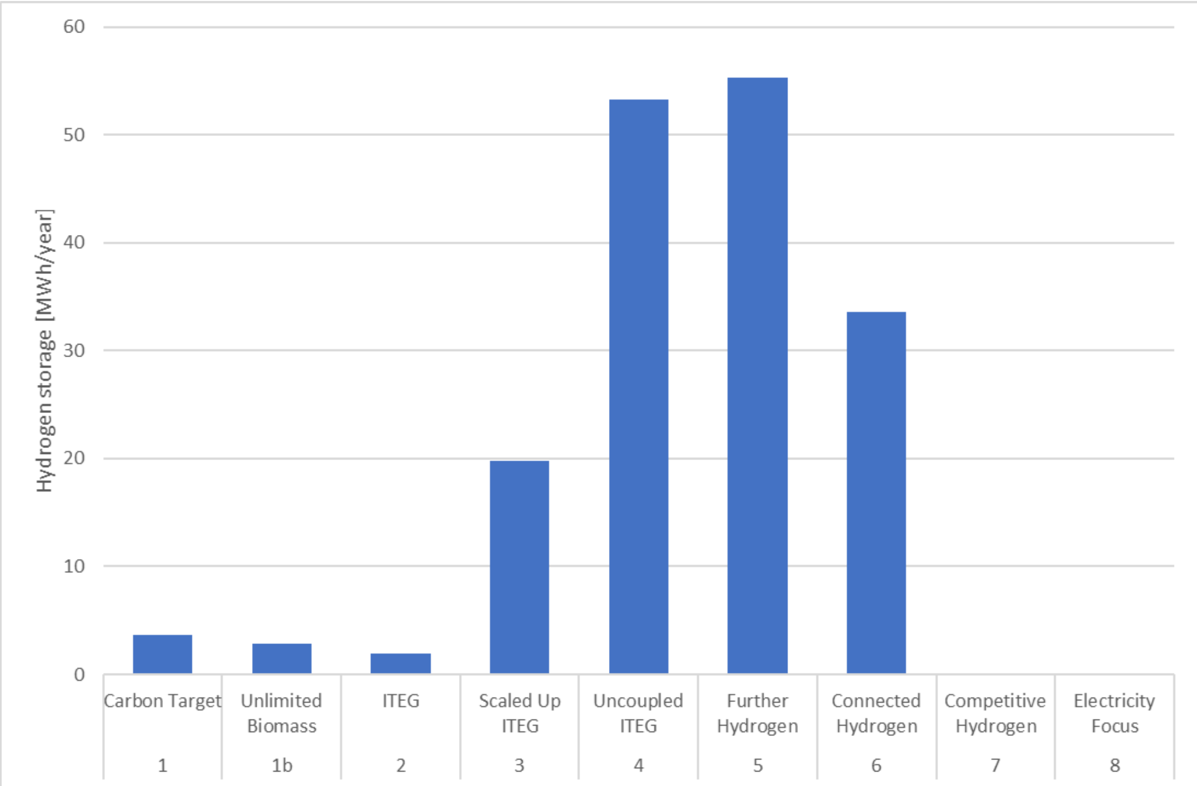

Figure 34 – Use of hydrogen storage in 2050 (total stored)

4.2.6 Electricity Network Infrastructure

The estimated investment required in upgrading the low voltage (400V) and high voltage (11kV) electricity distribution networks is shown in Figure 35 for each scenario[52].

Studies run as part of the validation exercise which is reported in section 3 showed that, even without imposing a requirement to reduce carbon emissions, investment in network reinforcement is required to meet demand by 2050. This is because certain aspects of consumer electricity demand are prescribed externally to the model, particularly take-up of electric vehicles. Beyond this, network reinforcement is driven by electrification of building heat. In some scenarios the model deploys more (cheaper but less efficient) direct electric heating options which requires higher levels of reinforcement. This is mostly in domestic buildings in central Stromness in scenarios 1 and 2 when there are limited hydrogen options. Similarly, air source heat pumps are fitted rather than ground source heat pumps in non-domestic buildings on Flotta and Central Mainland.

The analysis areas requiring most investment in electricity network upgrades are broadly the same across all scenarios, with minor variations. With the majority of all network upgrades at 400V and 11kV seen within Orkney Mainland, it is valuable to note the common changes seen across all scenarios, as these show consistent investment needs despite other uncertainties in future system changes.

Mainland Central and Central Kirkwall see the largest investment, with only the former seeing any variation between scenarios, the most significant being in HV substations in scenario 8. Scenario 8 also sees investment in South Ronaldsay exceed that in Central Kirkwall due to HV Feeder reinforcement. These investments are driven by increased wind generation in scenario 8 – the precise scale and location of what is required will be dependent on the locations chosen for any additional wind generation. The remaining areas of Orkney Mainland (Mainland North and Mainland West) account for the next largest investments and also see little change between scenarios.

By scaling up the ITEG technologies in scenario 3 onwards, more energy can be generated close to the demand, thereby reducing network investment costs relative to the smaller scale deployment in scenario 2. Scenario 4, which offers the freedom to site electrolysers close to the hydrogen demands, requires slightly more investment in electricity distribution upgrades with the need to upgrade HV feeders dominating.

[52] These are future investments discounted to 2020 values. Values of costs or benefits in the future are not representative of the actual worth in the present day (due to inflation etc.)

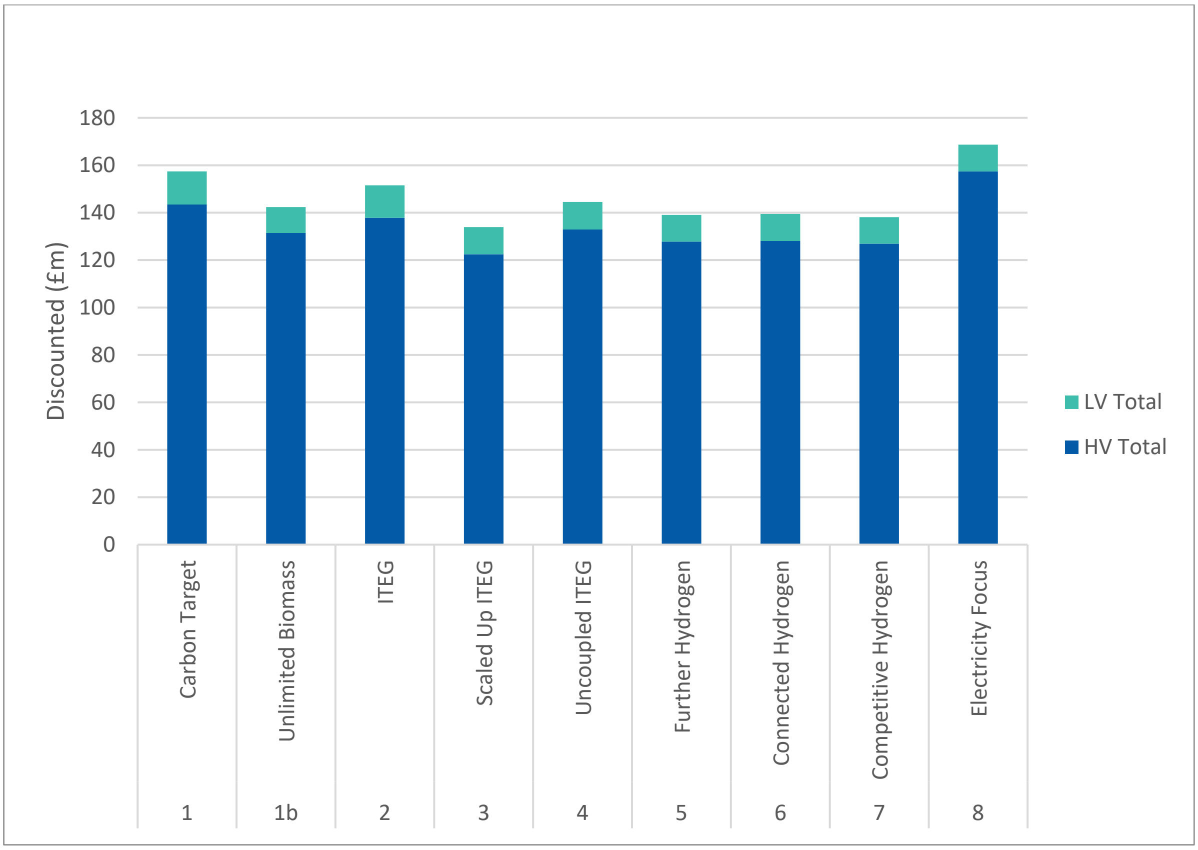

Figure 35 – Total Investment in electricity distribution networks to 2050

Table 4 overleaf shows which 33kV subsea network links are upgraded for each scenario and Figure 36 shows the approximate locations of these transmission links. Only limited upgrades to these parts of the network are required in the modelling. This is a result of increased electrification of heat (and use of electrolysis to produce hydrogen for local consumption) allowing much more renewable generation to be used locally, reducing current export constraints.

It should be noted that these studies have only a simple power flow representation of the network and much more sophisticated electrical modelling would be necessary to draw firm conclusions on requirements for network upgrades. Nevertheless, these results give a useful indicator of areas likely to need investment.

Table 4 – Inter-Island 33kV electricity link upgrades by scenario

Inter-island Electricity Link Upgrades	Scenario 3 Scaled Up ITEG	Scenario 8 Electricity Focus
(1) Rousay-Westray	Yes	Yes
(2) Orkney Mainland - Hoy		Yes

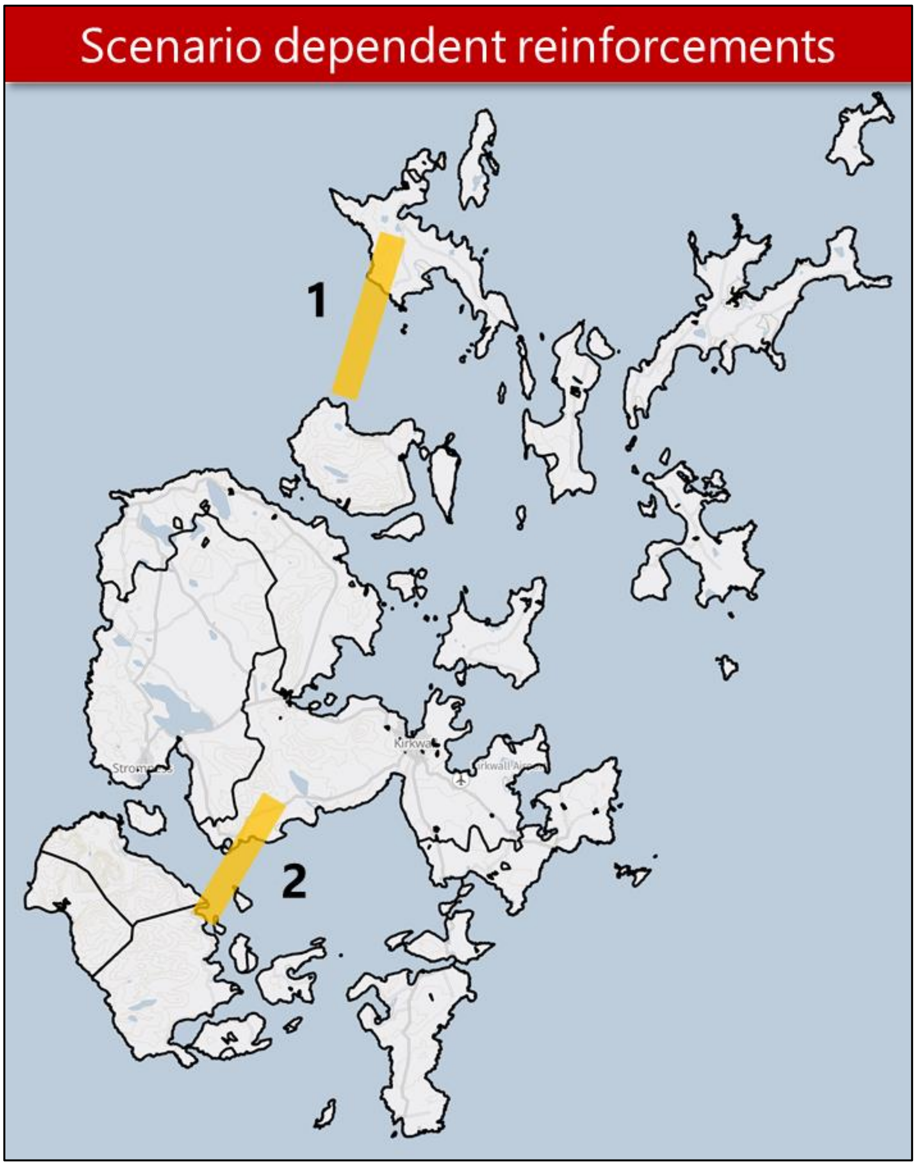

Figure 36 – Scenario dependent inter-island 33kV electricity link reinforcements

4.2.7 Total System Costs

Figure 37 shows the total, cumulative discounted energy system cost for each scenario. These total system costs include all operational and capital costs out to 2050 (i.e. everything from generation to end use, including cost of building modifications, technologies, imported energy and more). Costs increase from scenario 6 onwards as these later scenarios include decarbonisation of the ferry fleet which is not accounted for in the earlier scenarios.

It can be seen that scaling up use of ITEG technologies (from scenario 3 onwards) helps to reduce the overall Orkney energy system cost to 2050. Scenario 8 has a value that is significantly less than the costs for all other scenarios. This is because construction of the increased capacity electricity link to the UK mainland enables a significant increase in the amount of energy that can be exported from Orkney and the value of these exports is deducted from the total system cost.

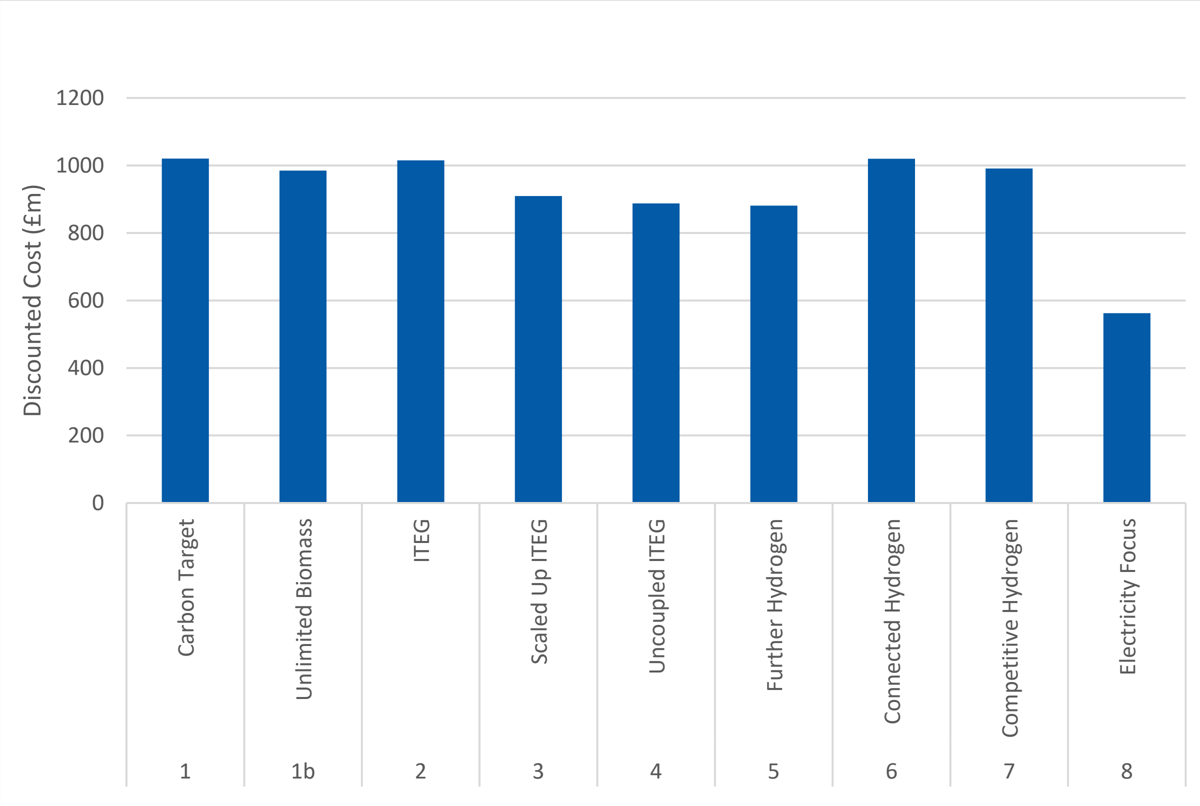

Figure 37 – Total energy system costs for each scenario

The breakdown of costs by categories is shown in Figure 38 with negative values indicating the sale of electricity and hydrogen that is exported from Orkney. In general the largest costs are assigned to the 'Tech' category. This includes all new local renewable generation (tidal and wind) as well as all electrolysers and hydrogen fuel cells. For Scenario 6 onwards it also includes the deployment of hydrogen ferries. The variation of total energy cost is dominated by these technology investments and trading-out electricity and hydrogen.

In scenario 8 the influence of enabling much larger energy exports through construction of the increased capacity electricity link to the UK mainland can be clearly seen (as discussed above).

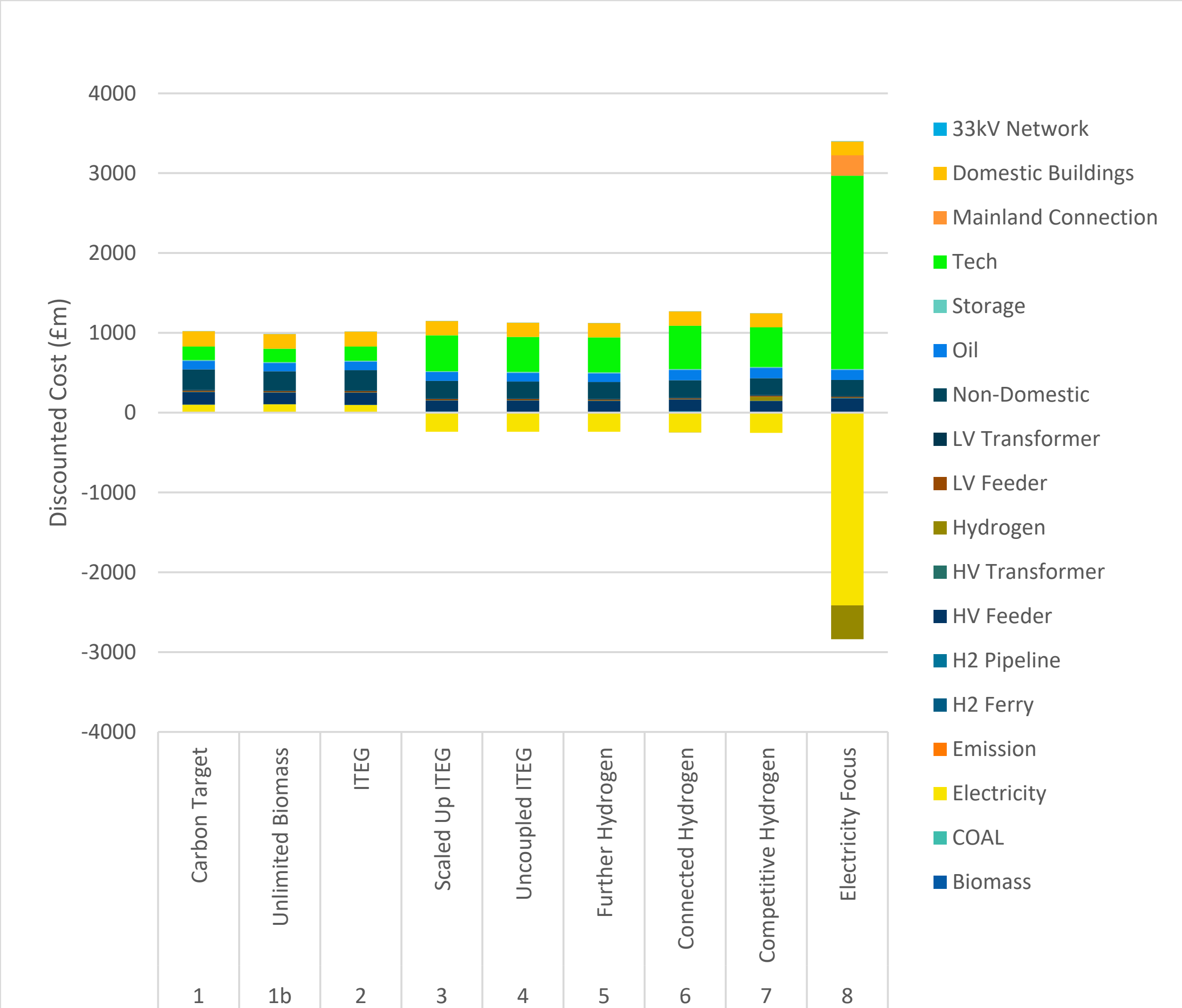

Figure 38 – Breakdown of Total System Costs

<u>Capital Costs</u>

Figure 39 overleaf shows the breakdown of total capital cost to 2050 by category and scenario. H2_Ferry refers to tube trailers for shipping hydrogen by ferry between islands.

In scenarios 1, 1b and 2, the largest capital cost comes from domestic buildings, with a variety of investments needed, including insulation and changes to heating systems.

The largest capital costs in scenario 3 are due to the new technologies introduced when scaling up use of ITEG (i.e. additional tidal turbines and electrolysers). Besides meeting demand within the Orkney energy system, the model results show that export revenue from trading out electricity motivates more investment in generation. Uncoupling the ITEG technologies (scenario 4) gives more flexible options for location of electrolysers and tidal generations, which reduces the investment needed for transporting hydrogen across the islands. Scenario 6 introduces a new 30GWh annual demand for ferries with an associated increase in capital investment required. With the ability to import hydrogen, scenario 7 sees this significant hydrogen demand met by sourcing from outside of Orkney with a change to hydrogen flows and associated infrastructure costs.

Scenario 8 shows that upgrading the interconnection link to the UK mainland motivates large scale tidal and wind generation on Orkney, resulting in a dramatic increase in investment in both technologies and transmission upgrades.

Other significant capital costs across the scenarios include non-building changes and HV network reinforcement. Costs labelled as '33kV network' are specific connections between islands and have a much lower total cost of upgrade than the total required for other network reinforcement.

(Costs for hydrogen ferries and pipelines; storage; and LV feeders and LV transformers, are too small to be visible on this figure).

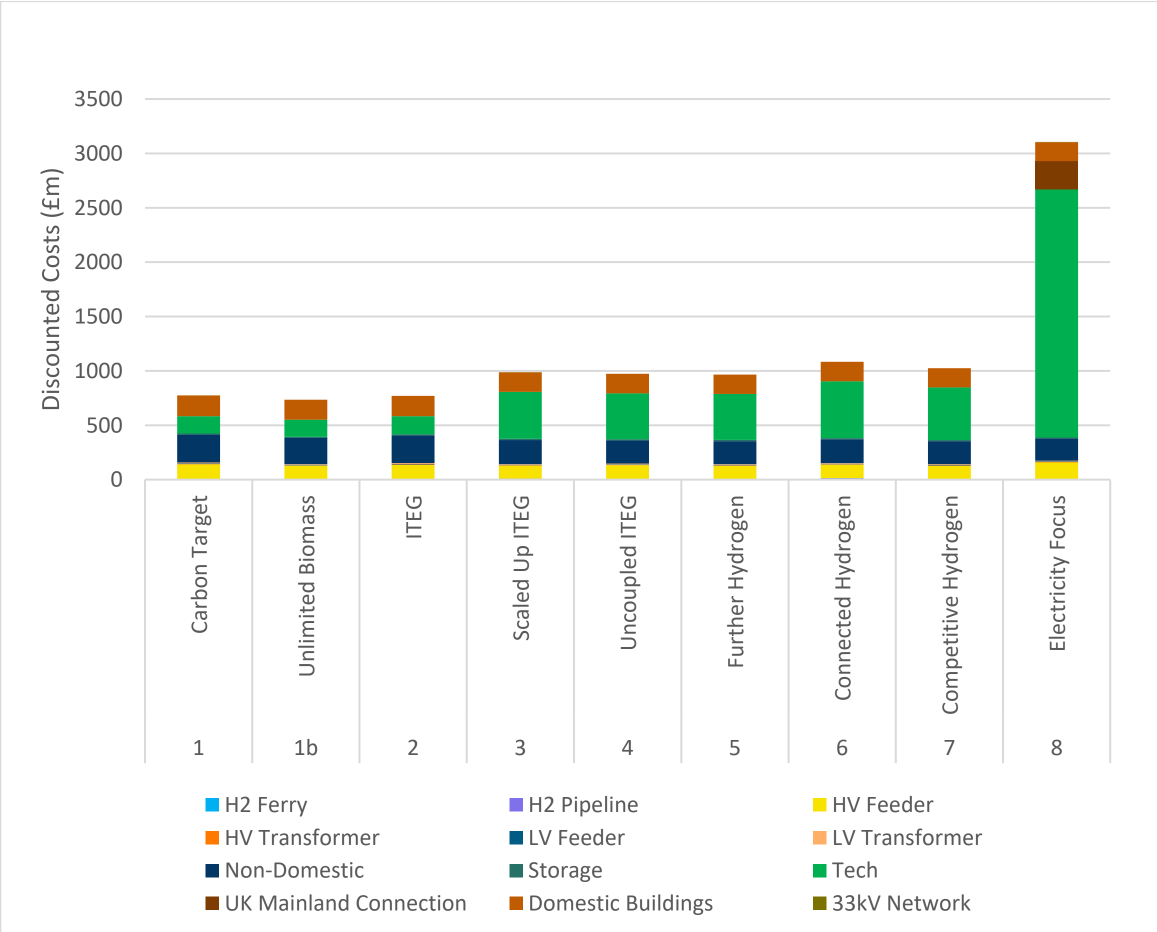

Figure 39 – Capital costs by category for each scenario

<u>Operational Costs</u>

Figure 40 shows the total operational costs to 2050 by scenario and category.

This includes the ongoing operation and maintenance costs of using technologies (labelled at 'Tech') and the costs of maintaining and operating energy networks. It does not include associated energy costs. The operational costs for technologies take a bigger proportion with ITEG scaled up, from scenarios 3 to 8. Scenario 8 show a much larger technology cost, as the optimiser selects more renewables once the UK mainland transmission link is upgraded.

Comparison between scenarios 3 and 4 shows that more ferries and pipelines are used to transport hydrogen if ITEG technologies are coupled as tidal turbine and electrolysis co-located, which requires the system to deploy more hydrogen infrastructure to move hydrogen freely for each area. Scenario 6 results show the ferry link between Eday and Orkney mainland that is required to meet an increase in tube trailer movement of hydrogen by ferry.

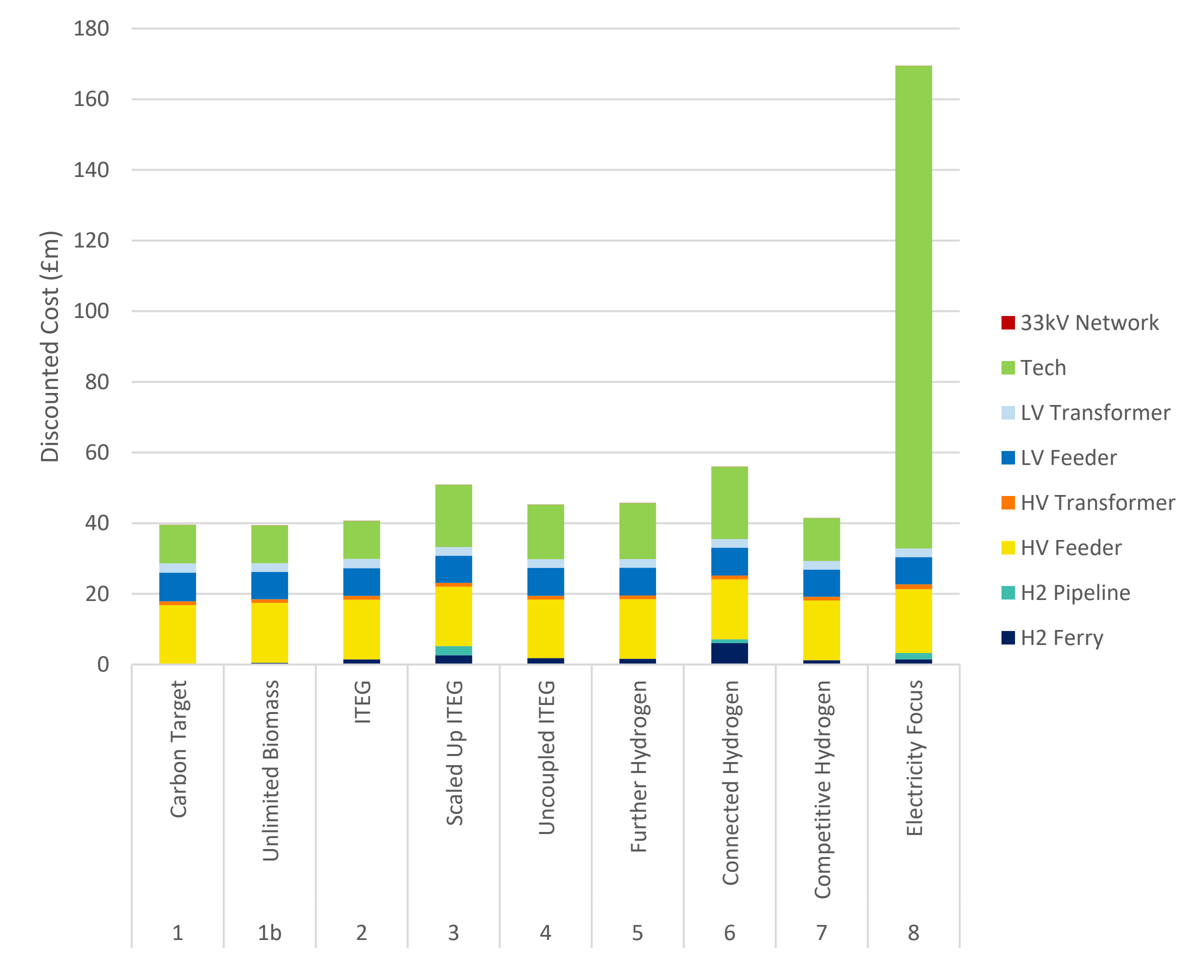

Figure 40 – Operational costs by category for each scenario

5 Discussion

5.1 Value of ITEG Technologies & Hydrogen Infrastructure

The technologies as planned to be deployed in the ITEG project are demonstrators of the future potential, and as deployed (i.e. at the scale of only a single turbine and electrolyser) will not have a significant impact on the overall Orkney energy system. However, analysing the changes arising from their deployment, even at this scale, can help inform an understanding of what might be possible if they were deployed at a larger scale.

Having the ITEG technologies available allowed the modelled Orkney energy system to reach a lower carbon point in 2050 than if they weren't present. This is because the hydrogen generated is used to help decarbonise a small number of buildings – domestic and non-domestic.

Some of these buildings – mainly non-domestics – are relatively difficult to decarbonise electrically. They may currently use oil and may be easier to decarbonise with hydrogen. Non-domestic buildings are far more variable than domestics, and it is hard to draw general conclusions from datasets as to how easy they are to decarbonise, as this may depend on the specific industrial process being undertaken in each one. In addition, changes in industry over the time studied can have a bigger impact than options to decarbonise them (although these are hard to predict and are not within the scope of this analysis).

When scaling up the ITEG technologies from scenario 3 onwards, a greater level of carbon saving was achieved with limited emissions remaining. These are entirely related to use of peat in distilleries and residual emissions in imported electricity neither of which had mitigation options in the modelling. With the modelling assumptions made regarding decarbonisation options for some industrial buildings, a source of hydrogen is required to achieve these low levels of residual emissions. The lowest levels of residual emissions are not achievable without local electrolysis (or an option to import hydrogen), although they can be achieved without tidal generation through increased use of wind generation.

As well as reducing carbon emissions, an energy system using the ITEG technologies has the potential to be lower cost than one without them, as local generation and hydrogen production allows local production of zero carbon hydrogen and electricity which are both required to achieve net zero.

The least cost energy system does not always co-locate electrolysers with tidal generation. Increased electrification required to achieve net zero means that more electricity from local renewable generation can be used locally, reducing the requirement to export this energy. This has the potential to free up capacity on the inter-island 33kV network and provides the opportunity to produce hydrogen closer to where it is being used which, in turn, reduces the level of investment required in hydrogen infrastructure (tube trailers or hydrogen pipelines). It also means there is a limited requirement to ship hydrogen for use in hydrogen fuel cells as a way of avoiding network constraints.

This analysis has focused on techno-economic factors, but ultimately there are political, social and regulatory constraints on energy system change. A system with the ITEG technologies in place may ultimately be more appealing than one without hydrogen because the regulatory environment discourages electricity network reinforcements needed to maintain a decarbonised system without hydrogen, or because hydrogen used may give some consumers a better experience than heating using electricity. Our modelling suggests that other more novel uses of hydrogen, such as in ferries or other marine vessels would increase the value of a further hydrogen system.

Alternatively, regulatory constraints on the future hydrogen system (for example the safety case for hydrogen storage trailers to share a ferry with other passengers) may influence the choice of hydrogen transmission technology, electrolysis location or even the choice between greater electrolysis and greater electrification. These aspects are explored in more detail in an accompanying "Hydrogen Handling and Logistics" report (deliverable LT.4.3).

5.2 Supporting Technologies

There are a number of other technologies not directly implemented in the ITEG project which the analysis shows as having high value in Orkney. The use of these other technologies may be important in enabling the energy system where hydrogen and tidal generation can play a role.

Across all the scenarios a large number of ground source heat pumps are deployed in both domestic and non-domestic buildings across Orkney, alongside significant insulation improvements in building fabric. By installing ground source heat pumps, more Orkney buildings can take advantage of the low carbon electricity that is available, switching away from oil. This has the potential to increase demand for, and value of, local generation options including tidal generation.

The model's choice to deploy ground source heat pumps where possible suggests that it is cost-effective to use the most efficient heating option, with the greatest coefficient of performance (at a greater upfront cost). Compared to other electric systems with lower coefficients of performance (e.g. electric resistive heating or air source heat pumps) this reduces the peak load on the electricity network and so allows more demands to be electrified. Similarly, the high level of additional insulation measures reduces the peak demand and so creates more capacity headroom on the network, although this may not correspond with network constraints if they are driven by times of maximum local electricity generation.

In non-domestic buildings there is also significant use of hydrogen. This is primarily associated with building uses that are harder to heat with electric solutions such as workshops and light industrial premises. There is also the potential for hydrogen use in some industrial processes.

Even with a hydrogen based system there is a need for significant electricity distribution network reinforcement at both 400V and 11kV. The 33kV link between Rousay and Westray appears most likely to need reinforcement across the scenarios. In contrast there is much greater variation in the needs for distribution level reinforcement, which appears sensitive between the scenarios, with different locations requiring the upgrades depending on the scenario. These requirements for upgrade are driven by peak loads and so depend on precisely which elements of demand get electrified in each scenario. Given the high level of sensitivity, a more uniform upgrade of the distribution network across Orkney may be what is practically required, as it will be hard to target specific upgrades at that level given the amount of variance shown.

The uptake of EVs on Orkney is a key action towards decarbonisation of transport and provides a route to use more locally generated electricity if the timing of charging can be matched to the timing of supply. The EV charging impact on network headroom needs to be considered in conjunction with the impacts of electrifying building demands, and both are included within the model. However, the potential benefits of smart charging or other flexibility services are outside the scope of this project – although they are being assessed within the ReFLEX project. Any demand that can be served by hydrogen may help release network capacity.

5.3 Developments in Orkney Proposed Recently

After the majority of the modelling and analysis was carried out for this project, various future large scale developments to the Orkney energy system have been publicly proposed by interested parties. Two of these, below, are of particular importance.

5.3.1 The Flotta Hydrogen Hub

A partnership (which includes EMEC Hydrogen) has been formed to develop this multi-billion pound project[53], announced in October 2021. If successful, implementation would occur later in this decade.

The intention is to repurpose part of the existing oil terminal area to create a green hydrogen hub, comprising a large scale electrolysis facility, powered by offshore wind, with a hydrogen export facility from which hydrogen could be exported to Europe or other destinations, and/or blended into the gas grid at St Fergus (on the UK mainland), and/or supplied to an international maritime green hydrogen refuelling hub.

Note that the analysis in this project was carried out prior to information on the proposed Flotta Hydrogen Hub development becoming available, and so this option was not specifically modelled, although this is similar to scenarios which were modelled that include a large electrolysis and export facility assumed to be at Flotta (i.e. scenarios 6 onwards; see section 4.1.8).

As discussed in this report, such a facility would benefit from significant economies of scale and cost reduction of hydrogen production, and would avoid many of the challenges of hydrogen handling and logistics discussed in Deliverable LT.4.3 which are associated with more distributed hydrogen production in an archipelago.

Also as discussed in this report (for example, in relation to scenarios 4, 5 and 6 in sections 4.1.6, 4.1.7 and 4.1.8), it would be an economic solution for Orkney's own energy system, co-locating the hydrogen production with the largest hydrogen demand and investing in the electricity supply directly to it.

It is possible that the pipework infrastructure to transport a smaller quantity of hydrogen from this hub to a number of the islands (to feed local demand, seen as likely to be required in scenarios 6 and onwards) might be funded in part through such a large-scale project, and thus accelerate hydrogen development and system decarbonisation across Orkney.

It would be strongly beneficial if tidal generation, as it is deployed at greater scale in the next few years alongside wind generation, was also connected into the energy system in such a way as

[53] See https://www.flottahydrogenhub.com/

the system value of diversity could be fully realised (relative to the lower value of deploying a single generation technology), as discussed in several places in this report.

It is notable that this proposed development strongly reinforces and commercially validates ESC's recommendations in this report – both for Orkney itself and as a model for roll-out of similar solutions in other locations. (Refer also to Deliverable LT.2.3 "Opportunities for Roll-Out of Tidal Generation with Electrolysis Across North West Europe").

5.3.2 The West of Orkney Windfarm

Related to the above, a project is being developed to build a 2GW wind farm about 25km west of Orkney[54]. First power is scheduled for 2029.

The electricity generated is planned to be exported via a new link to Caithness, on the UK mainland. Additionally, the project partners are exploring an option to power the Flotta Hydrogen Hub.

Note that the analysis in this project was carried out prior to information on the proposed wind farm development becoming available, and so this option was not specifically modelled, although a more modest amount of additional wind generation is included in scenario 8 (see section 4.1.10). Nevertheless, some useful insights can be derived, as follows.

This proposed wind farm would enable green hydrogen production at the Flotta Hydrogen Hub, which would be highly beneficial.

It is also interesting to compare the scale of ambition for this infrastructure against the state of the electricity network infrastructure on Orkney at present, and particularly noting the very long-running regulatory impasse which has prevented investment in the far more modest 220MW interconnector from the UK mainland to Orkney.

This report has highlighted the clear case for immediate investment, without further delay or preconditions, in that 220MW interconnector and has highlighted the many benefits to the overall Orkney energy system that this would enable (see section 4.1.10). If further deployment of larger-scale tidal generation is to be enabled, and if the full potential benefits are to be realised within the wider Orkney energy system (rather than just bypassing it), then **a significantly larger capacity interconnector between the UK mainland and Orkney is likely to be required**.

There appears to be a stark difference between the case for investment as seen by the regulators and the case as seen by renewable generation companies. The West of Orkney Windfarm developers are considering 'private wire' infrastructure to enable the project to proceed, but **the wider opportunities for a whole-system approach enabling further developments (such as larger scale tidal generation) and system benefits for the whole of Orkney are unlikely to be realised without a more joined-up, forward-looking vision from the regulators allowing investment in public infrastructure**.

[54] See https://www.westoforkney.com/project

6 Related Analysis During the Project

Building on the whole energy system modelling and analysis reported in this deliverable (Deliverable LT.4.2 "Whole Energy System Analysis: Long Term Impacts on the Orkney Energy System"), ESC and its ITEG project partners carried out a number of related activities within the Long Term Impacts work package, the most important of which are as follows.

Roll-Out

These explored the challenges and opportunities for roll-out of tidal generation with electrolysis in other island, coastal and remote communities, identifying areas across north-west Europe which are likely to have ample tidal resource, potentially significant hydrogen demand, and in some cases constrained electricity networks, and thus might be most attractive for deployment of these technologies. For details, refer to:

- Deliverable LT.2.3 Opportunities for Roll-Out of Tidal Generation with Electrolysis Across North West Europe

Hydrogen Logistics

The logistics of producing, handling and transporting hydrogen in such settings were also explored, along with the challenges and opportunities presented. For details, refer to:

- Deliverable LT.4.3 Hydrogen Handling and Logistics: Challenges and Opportunities in a Remote Archipelago

Energy Management System Attributes

Options were explored for the control of generated electricity and hydrogen production, export to grid, storage, etc, focusing in particular on the relationship between these and the overall system design and benefits discussed in this report. For details, refer to:

- Deliverable LT.4.4 Energy Management System Analysis

Technology Roadmap and Business Case

A study of existing roadmaps for tidal and electrolysis technologies was undertaken, developing learning for the ITEG combination of technologies. (This complements deliverable LT.2.3 which addresses suitable deployment areas with likely hydrogen demand). For details, refer to:

- Deliverable LT.1.1 Roadmap Study for Tidal Generation with Electrolysis

Orbital Marine Power, working with ESC, developed a summary benefits case for the combined deployment of tidal generation with electrolysis, to attract and inform potential project investors. For details, refer to:

- Deliverable LT.1.2 Business Case for Tidal Generation with Electrolysis

Social Acceptance

A study of the issues relating to social acceptance of renewables, tidal generation in particular, and hydrogen production and use, was undertaken by a team comprising the University of Caen, the University of Le Havre Normandy, and Ghent University. For details, refer to:

- Deliverable LT.2.2 Social Acceptance Study

Summary

A succinct summary of the key findings from ESC's work on the ITEG project is set out in an easily-accessible format. For details, refer to:

- Deliverable LT.4.5 Summary of Findings from the whole energy system studies carried out under the ITEG project

7 Conclusions

The Orkney energy system has the opportunity for significant innovation and low carbon development, but also challenges to overcome, such as the limited network capacity. To achieve Orkney's net zero ambitions there is the opportunity to develop a number of innovative solutions that work with the energy resources available on Orkney. The ITEG project is demonstrating the opportunity that tidal turbines and electrolysers could bring to the area, as an approach that makes best use of the local low carbon energy resource.

The modelling work set out in this report sets a carbon target for Orkney that reaches net zero by 2050 and explores the value of these ITEG project technologies to the wider Orkney energy system in that long-term context. It considers their deployment both within the project and also at larger and wider scales to create a more hydrogen-intense system across the islands.

With the technology options modelled some residual emissions remain in the energy system related to use of peat in distilleries and, in some scenarios, residual emissions from electricity import whose existence is a result of limited local generation if the UK mainland electricity interconnector upgrade is not built. If this goes ahead it provides options for increased local generation which has the potential to make Orkney self-sufficient in low carbon energy.

Decarbonisation of buildings in the model is mainly through electrification of heat. However, results show that the availability of hydrogen through deployment of ITEG technologies at scale allows greater levels of decarbonisation, providing a low carbon solution for buildings that are hard to electrify, either because of their form and activity, or as a result of local network constraints. Without hydrogen being available (either produced locally or imported) the lowest levels of emissions cannot be achieved with the modelling assumptions made.

The modelling carried out has been based on a whole-energy-system cost optimisation tool. However, energy systems do not act solely in a whole system, cost-optimal manner. In practice, individual actors in the system take decisions to suit their own needs, and policy and regulation may enable or block desired innovation. In the Orkney context this could apply to both the hydrogen and electric parts of the system.

For example, expenditure on network upgrades will only be allowed by Ofgem under certain circumstances and it can be hard to get approved for such upgrades ahead of demand. This may increase the attractiveness of hydrogen options as, even if they are higher cost, as they may be easier to deploy than getting approval for significant electricity network capacity investment. Alternatively, some assumptions around the future hydrogen system may not be valid under current regulations (for example the safety case for hydrogen storage trailers to share a ferry with other passengers).

The modelling work conducted introduced increasing options either for deployment of ITEG technologies or for exploitation of them. The following findings were established:

1. Deployment of the single turbine and electrolyser unit within the ITEG project leads to a small reduction in imported electricity (by approx. 300MWh/year, or 1%, in 2050) and a more significant increase in exported electricity (by approx. 3.1GWh/year, or 20%, in 2050). The hydrogen produced is used mainly in commercial and industrial buildings. The ITEG tidal generator is used in conjunction with the existing flow-cell battery to maximise the use of the generated energy. Despite this, there is still a small amount of curtailment at times of peak generation (spring tides).
2. With ITEG technologies built as 'packages' of co-located tidal generation and electrolysis, a total of 5 packages of 20MW of tidal generation with 5MW of electrolyser capacity were deployed across Orkney. This deployment enables additional hydrogen production and further decarbonisation of industrial and commercial buildings, eliminating nearly all residual emissions in the model by 2050. With this level of tidal generation an additional 174GWh per year of electricity is exported by 2050. In order to enable this level of deployment and export, increased electricity network capacity is required between Rousay and Westray. There is also a need to build some hydrogen pipelines to move hydrogen from production locations to where demand exists.
3. If ITEG technologies are deployed separately, rather than as co-located packages, then three of the electrolysers are sited at different locations to tidal generation assets. Within the model, transport of electricity is found to be more cost effective than transport of hydrogen – partly as the need to build hydrogen pipelines is avoided. There is an 80% increase in consumption of electricity in domestic buildings as they are converted to electric forms of heating. This provides additional local demand for the electricity generated from renewables, freeing up capacity on the 33kV island ring.
4. Tidal generation can make a valuable contribution to the Orkney energy system regardless of the level of hydrogen production and use. This is primarily due to the highly predictable nature of tidal generation compared to other types of renewable generation and the increased diversification of the generation mix it provides, which has additional value to the energy system compared to installing only one technology.
5. The influence of access to a hydrogen export market changes with the market price assumed. Below a threshold level (modelled as £150/MWh[55], approx. £5/kg H_2) there is around 95MW of tidal capacity and 40MW (electrical power) of electrolyser capacity with little change to the Orkney energy system resulting from gaining access to a hydrogen export market. If market prices are above this level, and the UK mainland electricity connector is not built, then significant additional deployment of both tidal generation and electrolysers may be enabled, with increases of 500MW tidal and 200MW electrolysis achieved in the modelling. If the mainland connector is built then, at a hydrogen market price of £150/MWh,

[55] When considering the likelihood of certain market price levels, it is important that prices are compared on a like-for-like basis. In the modelling and analysis all energy prices were at the Orkney energy system boundary. Import costs quoted here therefore include shipping to Orkney (whereas figures in literature are often quoted as ex-plant prices only). For the same reason, export prices in this modelling do not include cost of shipping to customers. No attempt has been made to estimate what these shipping costs might be as part of this work. Although many people have suggested that future market prices may be well below this threshold, opinion is divided on how achievable such figures really are, and this work presents the analysis findings without attempting to second-guess actual future market rates.

renewable generation is more likely to be exported directly as electricity rather than converted to hydrogen for export.

6. The optimal way to produce hydrogen for export is to locate both tidal generation and electrolysers close to the export point, to limit the costs associated with reinforcing the electricity networks and building hydrogen networks. This suggests tidal installation in the Pentland Firth with electrolysers on Hoy or Flotta (assuming this is the export terminal). Any hydrogen required locally could then be shipped to elsewhere on Orkney from this central production hub.
7. If significant volumes of hydrogen are to be exported then it is likely that some hydrogen pipelines will need to be installed between the point of production and the export terminal. Alternatively, additional electricity network capacity might be required such that electrolysis can be located at the export point.
8. Introducing an option to also import hydrogen can change the choices made to reach net zero, with cheap hydrogen available for import at £75/MWh (approx. £2.50/kg H_2) or less leading to more use of hydrogen overall but with very little local production, whilst prices above £100/MWh (approx. £3.30/kg H_2) lead to higher levels of local hydrogen production (although this is still less than if there is no option to import hydrogen). Tidal generation capacity seems to be reasonably insensitive to whether hydrogen can be imported, regardless of price.
9. Changes to the market price of electricity do not fundamentally change the cost-optimised, net zero Orkney energy system. Whilst there are some changes to the precise levels of deployment of different technologies these are generally in proportion to the change in electricity price with more local generation at higher market prices, for example. This suggests that starting to implement the change required to meet net zero on Orkney can be done at relatively low risk with little chance of stranded assets.
10. Building the proposed 220MW interconnector to the UK mainland enables additional renewable generation which is a mixture of both tidal and wind generation (400MW of tidal and 140MW of wind are added when the hydrogen price is at or below the threshold level of £150/MWh (approx. £5/kg H2) at which large scale export is promoted when the mainland link is not available). The increased diversification of the generation mix has additional value to the energy system compared to installing only one technology. This additional renewable generation also creates opportunities for increased electrolysis with an additional 200MW deployed (when the hydrogen price is below £150/MWh) producing a total of 280GWh of hydrogen per year.
11. Building the electricity connector upgrade unlocks significant potential for the Orkney energy system allowing:
    - a significant increase in cost-effective wind and tidal generation to a level that makes Orkney almost self-sufficient in a decarbonised future, needing to import energy on only limited occasions through the year;
    - export of significant quantities of both wind and tidal generation, with possibilities for hydrogen export if markets can be accessed at a competitive price; and
    - opportunities to maximise the benefits of renewable generation through hydrogen production when generation is in excess of the combination of local demand and the capacity of the new interconnector.

12. Investment in the electricity interconnector upgrade, regardless of other factors, would therefore be a “no-regrets” decision which could be implemented immediately without pre-conditions, and there is a clear case for change in the present regulatory constraints.
13. Even with the new interconnector, the cost-optimal level of renewable generation deployment results in some curtailment at times of peak generation, as this is outweighed by benefits at other times.
14. Alongside this Deliverable LT.4.2 “Whole Energy System Analysis: Long Term Impacts on the Orkney Energy System”, a number of related activities and deliverables are listed in section 6 of this report. A succinct summary of the key findings from ESC’s work on the ITEG project is set out in an easily-accessible format in Deliverable LT.4.5.

8 Appendix A – Further Results by Scenario

This Appendix A supplements the headline comparative results, set out in section 4.2, with further results for each scenario individually.

Although there is a considerable volume of material set out in this report, there is of course a great deal more data within the model itself which has not been included in the report. If ITEG consortium partners are interested in any particular aspects, then they are encouraged to contact ESC so that those aspects might be included if appropriate in subsequent versions of the report.

For ease of reference, the chart of Analysis Areas is repeated below.

Figure 41 – Analysis areas modelled in Orkney

8.1 Scenario 1: A Carbon Target

In this scenario, Orkney is decarbonising without ITEG project technologies. It includes existing energy infrastructure such as wind generation and existing electrolysers and fuel cells and the flow cell battery at EMEC..

Most domestic demand (Figure 42) has switched away from oil to electricity by 2030. Although there is also a switch from oil to electricity amongst non-domestic customers (Figure 43) this is not as pronounced and happens in a later time period.

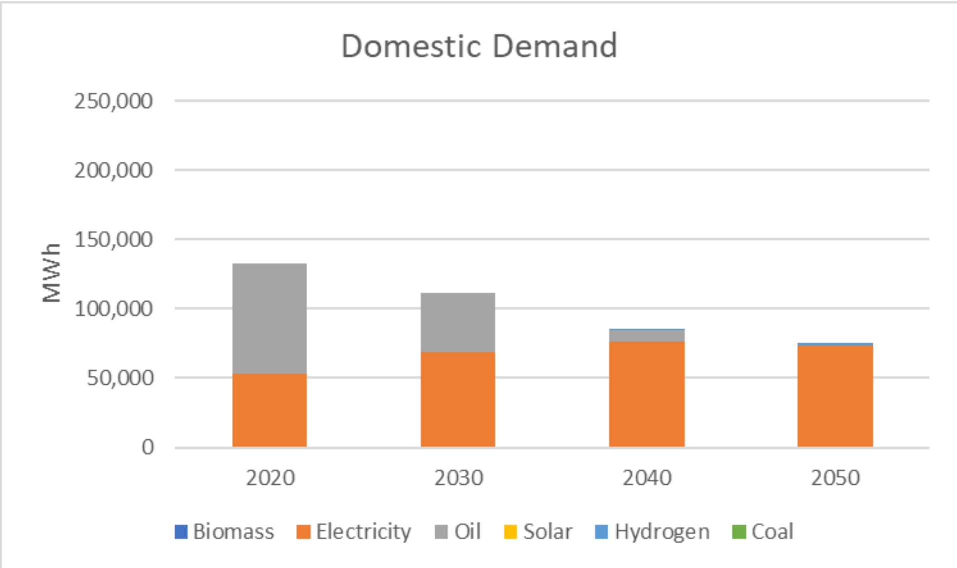

Figure 42 – Domestic demand, scenario 1

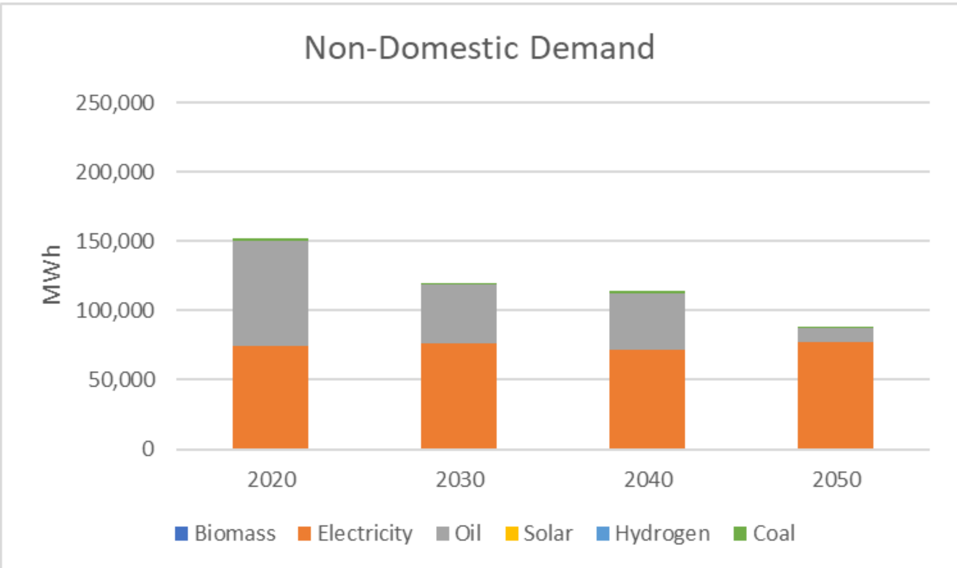

Figure 43 – Non-domestic demand, scenario 1

In 2020, domestic heating is predominantly by oil and electric resistive, with few heat pumps. There are a small number of properties with air source heat pumps and an even smaller number of ground source heat pumps, mostly on Hoy. Some areas such as Rousay use oil for heating in more than 90% of domestic properties.

By 2050, the model has chosen to convert most oil heating to ground source heat pumps, with some high temperature air source heat pumps. Figure 44 shows the domestic heating systems broken down by analysis area.

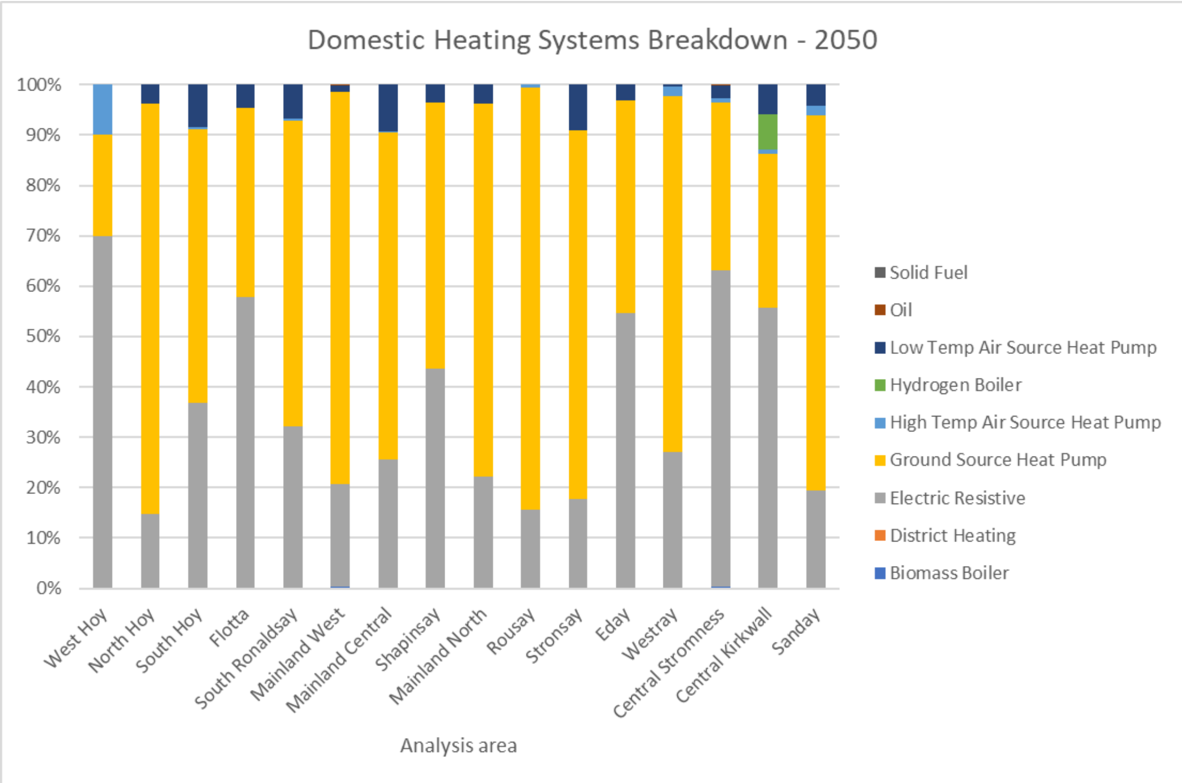

Figure 44 – Domestic heating systems, scenario 1

Figure 45 shows the percentage of domestic properties having insulation measures applied by 2050. South Ronaldsay, Central Kirkwall and Rousay are the only areas in which the majority of properties have the fullest ('advanced') set of insulation measures applied at the earliest opportunity presented within the model.

West Hoy has few measures applied but has only 10 properties in the model.

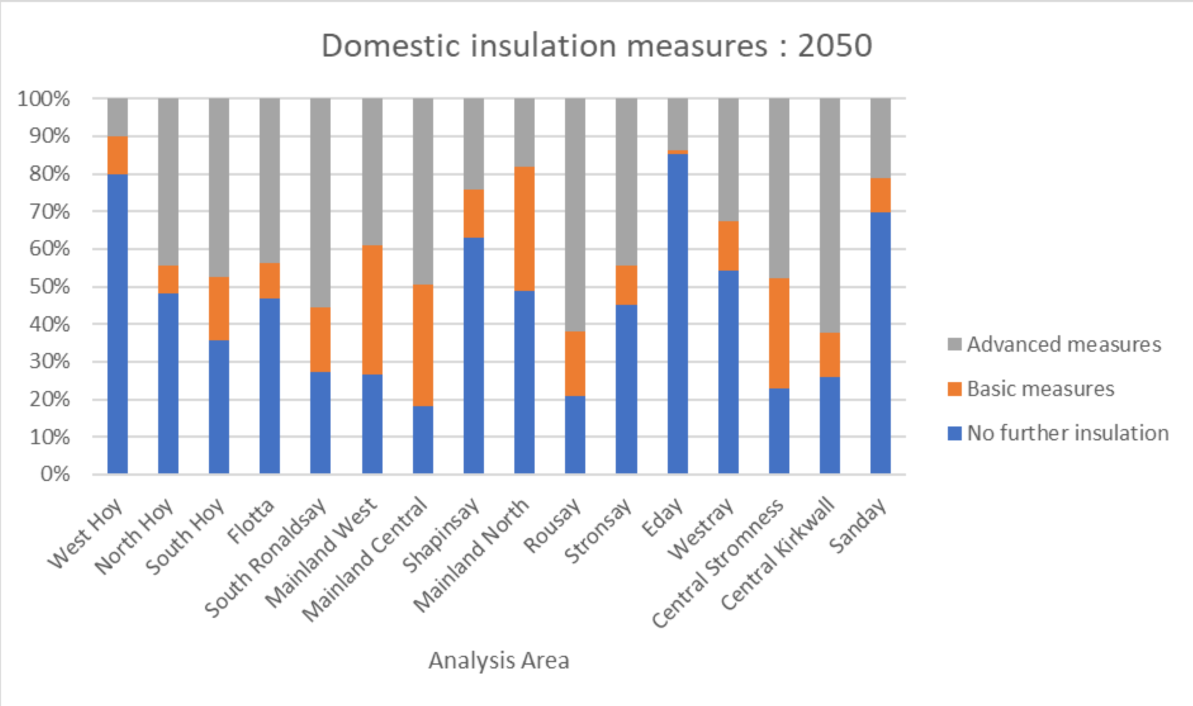

Figure 45 – Domestic insulation, scenario 1

In this scenario the majority of non-domestic buildings switch from oil-fired heating to heat pumps. Oil remains the dominant heating fuel on Flotta. Residual coal use in the model outputs is the result of using this to model peat use for malting barley in distilleries (particularly at Highland Park). There are no options in the model to replace this with alternative fuels due to it's direct influence on the flavour of the product.

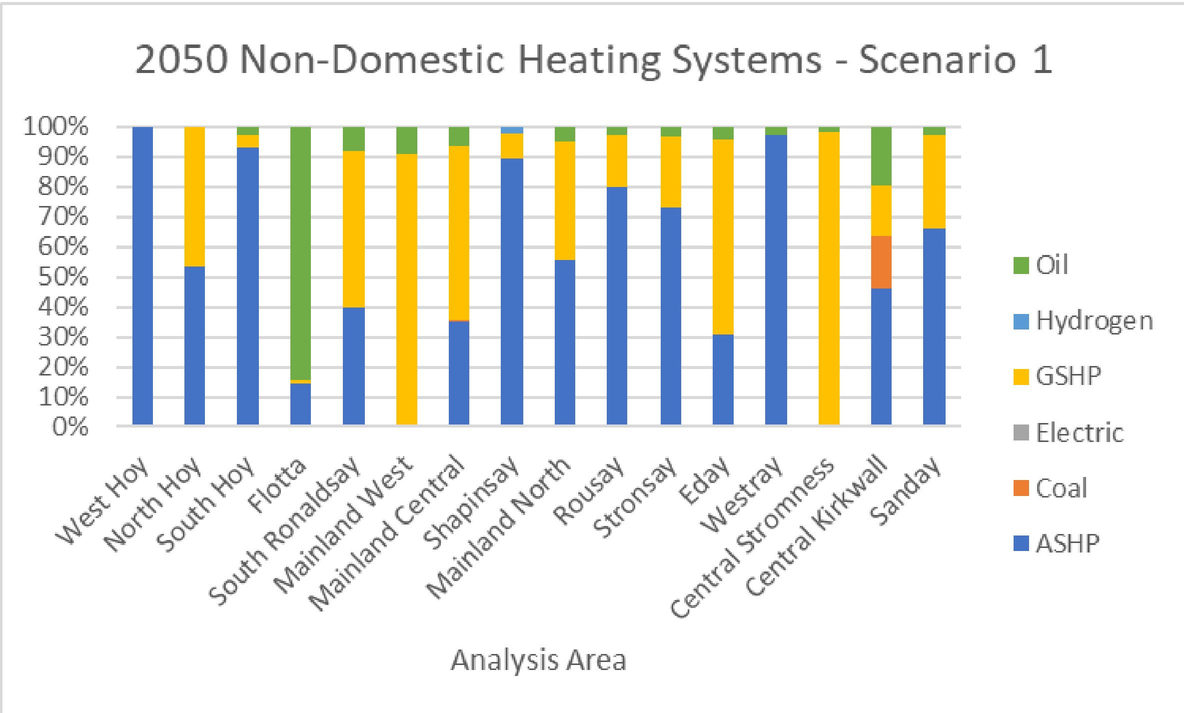

Figure 46 – Non-domestic heating systems, scenario 1

Figure 47 shows the changes of primary energy over time. Electricity displaces most oil use in domestic buildings, and there is some displacement in non-domestic buildings. There is a small increase in solar PV and wind generation. By 2050, emissions of CO_2 within the scope of the model are reduced to 3.28 ktCO_2/year.

The apparent dip in wind generation in 2040 is a consequence of the retirement and replacement of technologies. It is assumed that repowering requires a lengthy outage of the generator so there is a dip in production over that period. It so happens that many turbine retirements fall into this decade within the model.

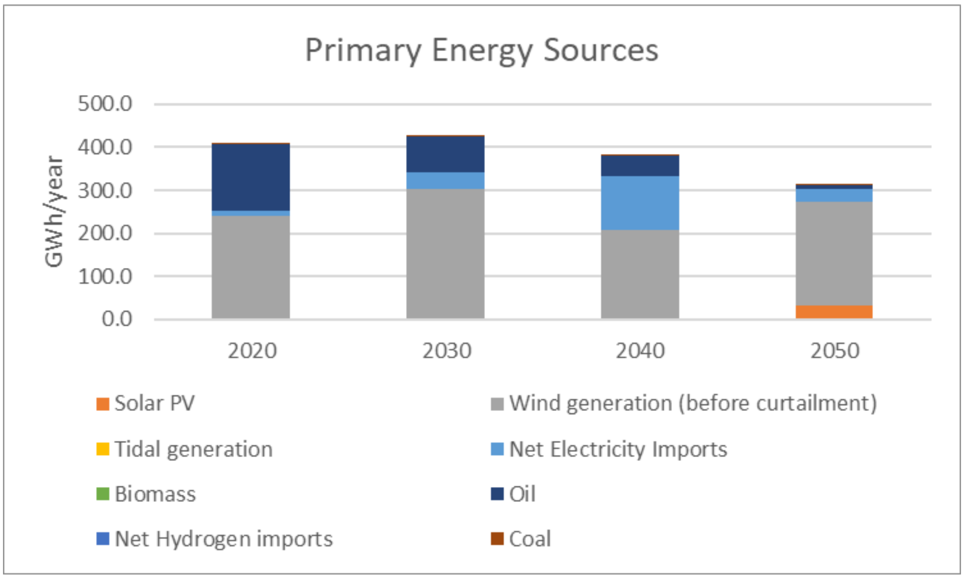

Figure 47 – Primary energy sources, scenario 1

8.2 Scenario 1b: Unlimited Biomass

In scenario 1b there is no facility to produce or supply hydrogen but the volume of biomass that can be imported is unlimited. This gives an indication of the possible scale of biomass use in the Orkney energy system if there is limited availability of hydrogen.

Notable in this scenario is the switching of all domestic heating away from oil-fired boilers (Figure 48). The majority is to electrical heating as in scenario 1, with biomass contributing around 3% by 2050. Whilst some oil use is retained amongst non-domestic customers, there is a greater contribution from biomass here (Figure 49).

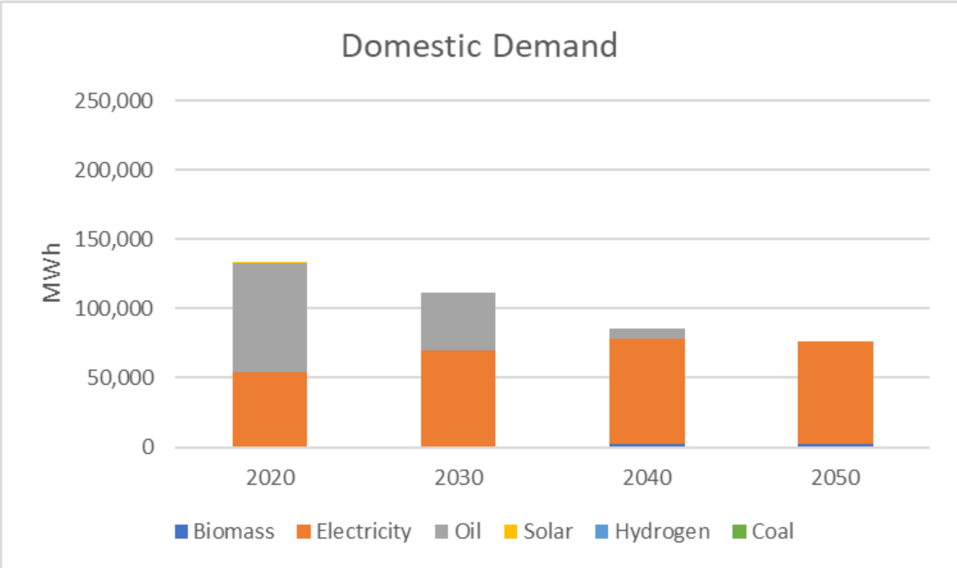

Figure 48 – Domestic demand, scenario 1b

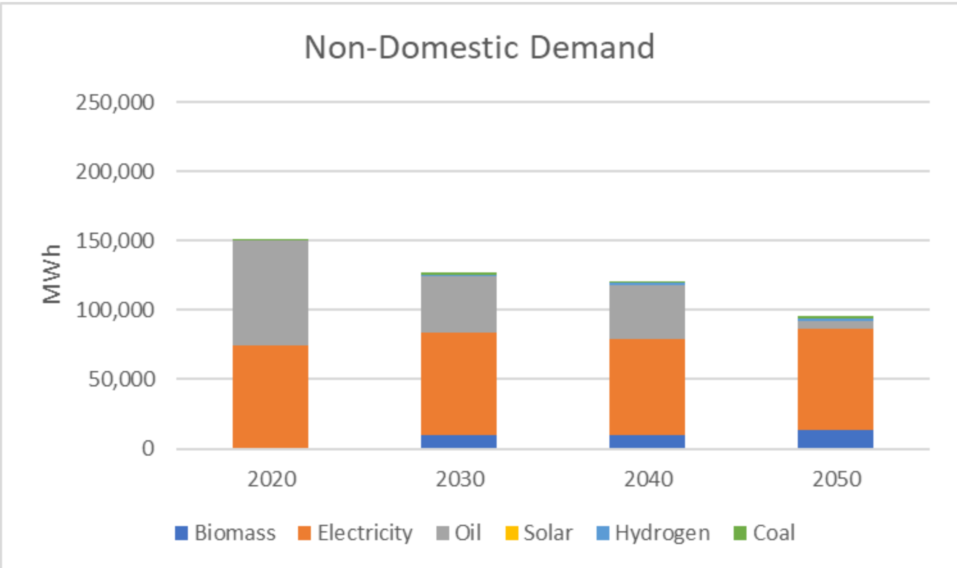

Figure 49 – Non-domestic demand, scenario 1b

Figure 50 shows domestic heating systems by analysis area. As in the previous scenario, oil-fired heating is mainly replaced by ground source heat pumps. No hydrogen is used for domestic heating. Biomass usage is confined to two areas on Orkney Mainland plus Rousay. There are in fact only 3 biomass boilers installed on Rousay, out of 153 properties modelled overall.

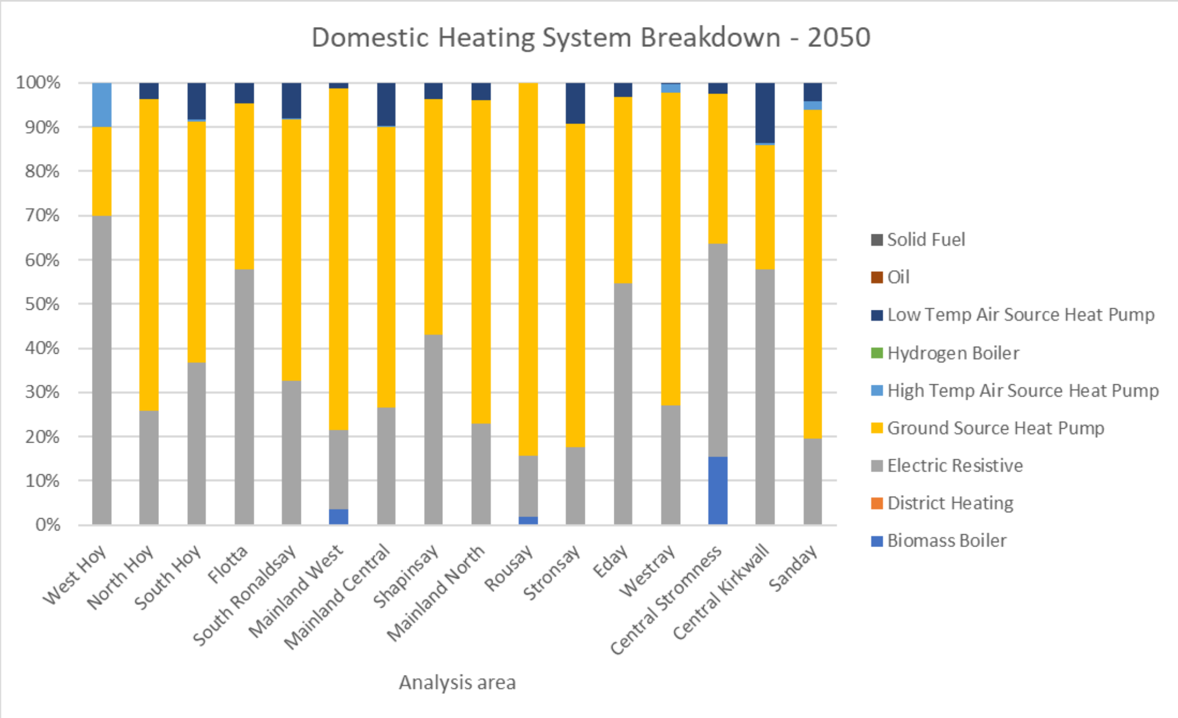

Figure 50 – Domestic heating systems, scenario 1b

Advanced insulation measures are more widespread than in Scenario 1, with over 50% of properties upgraded on some of the outer islands like Westray and Sanday (Figure 51).

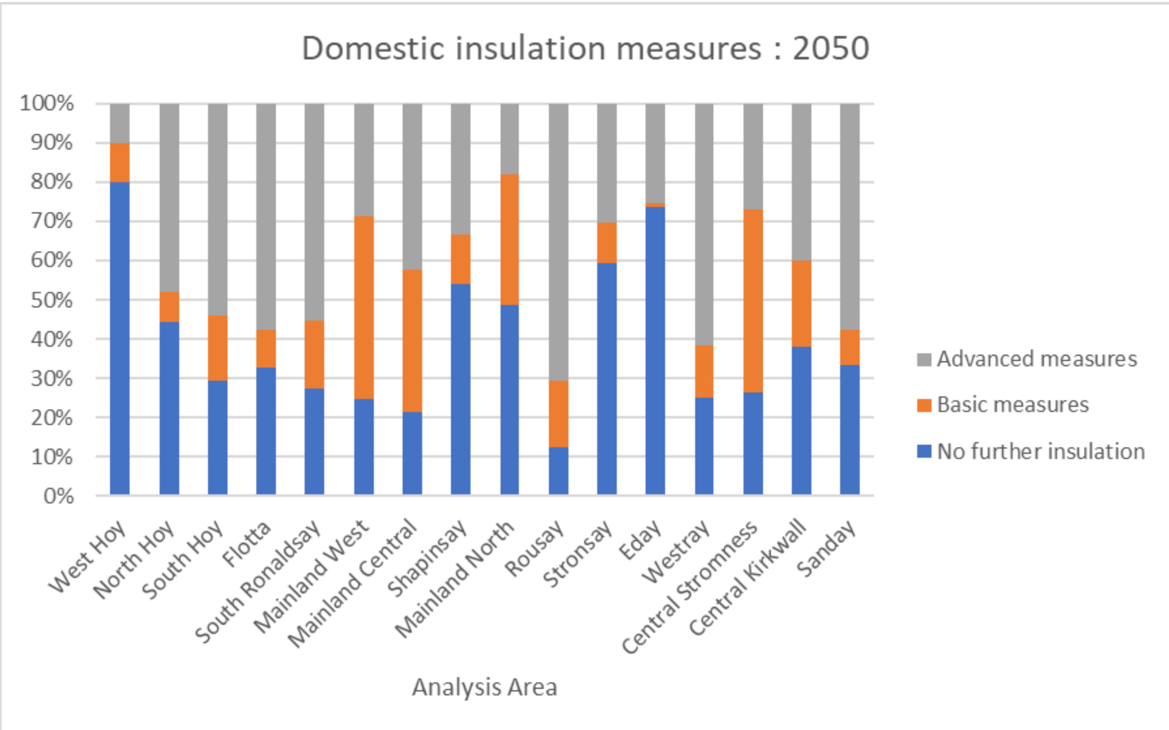

Figure 51 – Domestic insulation, scenario 1b

As in Scenario 1, the majority of non-domestic properties switch from oil-fired heating to heat pumps, apart from on Flotta where oil remains predominant (Figure 52). Biomass (most notably on Rousay and in Central Stromness) and to a limited extent hydrogen contribute to the overall energy mix. Flotta, Hoy, Eday and Sanday are the only islands with no hydrogen used for non-domestic heating.

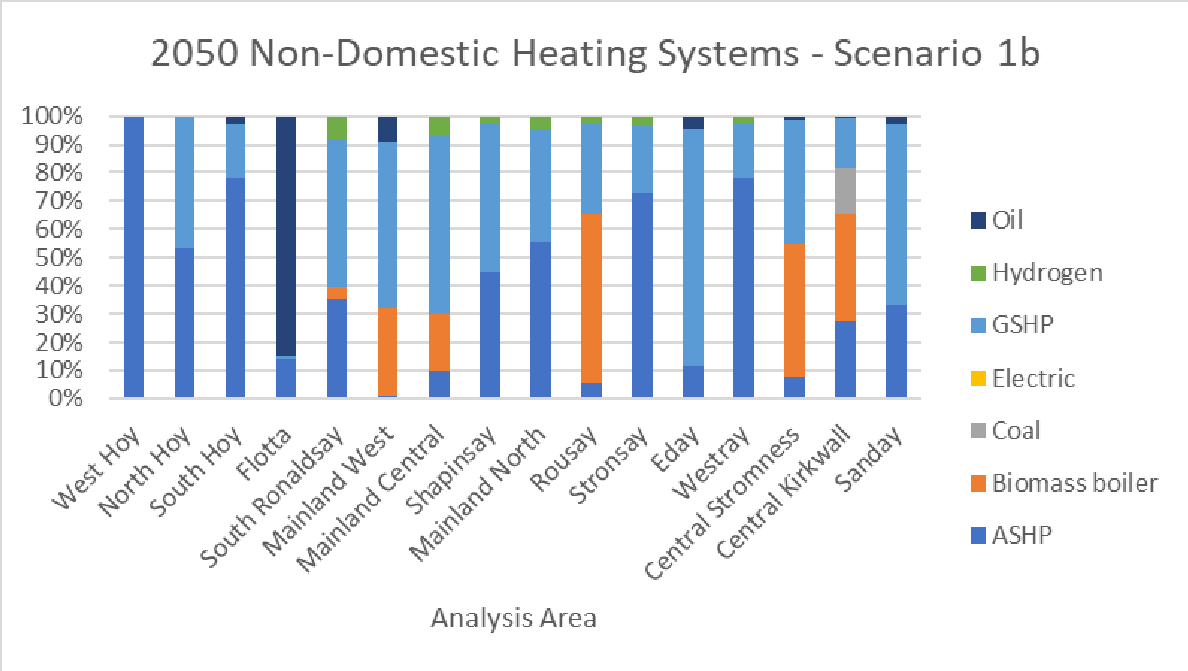

Figure 52 – Non-domestic heating systems, scenario 1b

Figure 53 shows the changes of primary energy over time. The choices made are very similar to those in Scenario 1.

The model as currently implemented does not have an option for biomass to displace oil consumption in non-domestic buildings. A more detailed assessment of industrial processes on Orkney would be required to know for which properties this switch would be feasible.

Carbon emissions within the scope of the model are reduced to 2.65 ktCO_2/year by 2050.

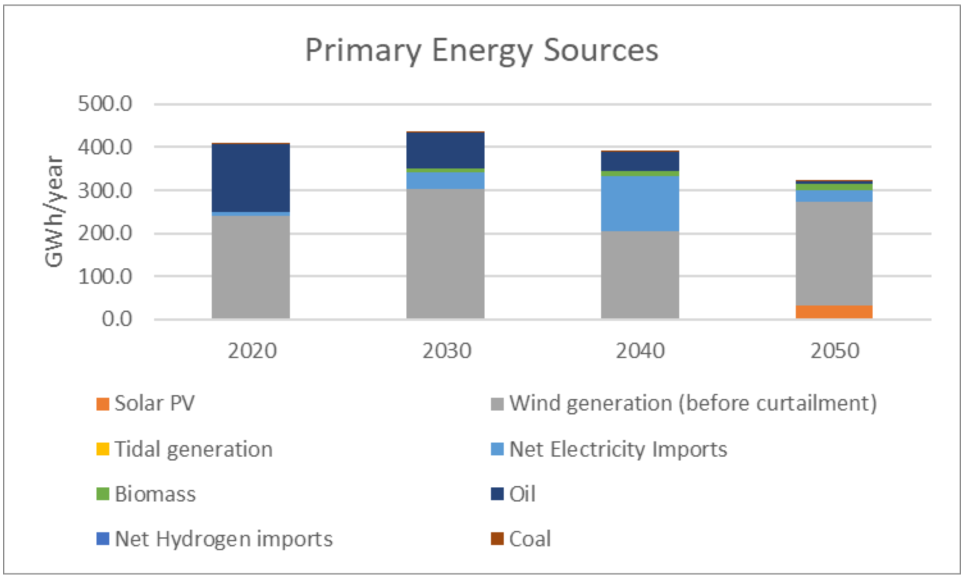

Figure 53 – Primary energy sources, scenario 1b

8.3 Scenario 2: The ITEG Project Technologies

This scenario models the impact of the ITEG project tidal turbine and electrolyser. Use of biomass is restricted to current levels.

The hydrogen produced by the ITEG solution allows some displacement of oil burning by hydrogen in both domestic and non-domestic properties (Figure 54 and Figure 55), but the scale is small with only a single ITEG turbine and electrolyser package deployed.

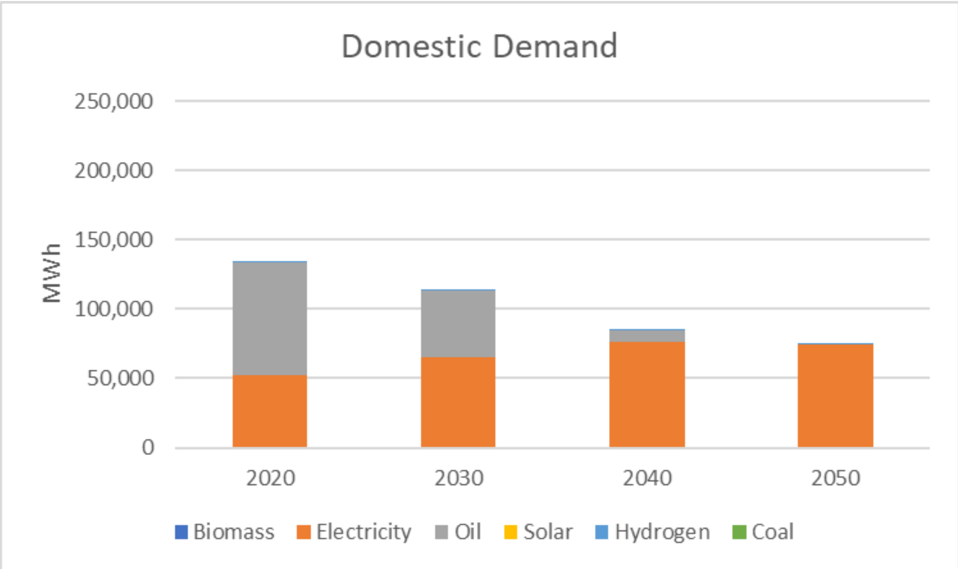

Figure 54 – Domestic demand, scenario 2

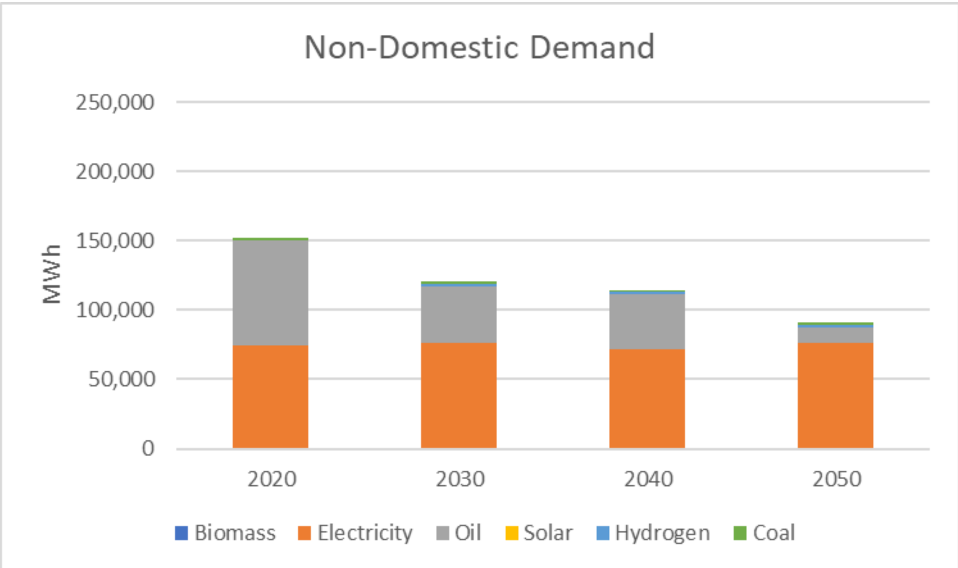

Figure 55 – Non-domestic demand, scenario 2

Figure 56 shows domestic heating system by analysis area. The installation of hydrogen boilers is confined to central Stromness. Overall the model prefers to install ground source heat pumps that switch from oil boilers.

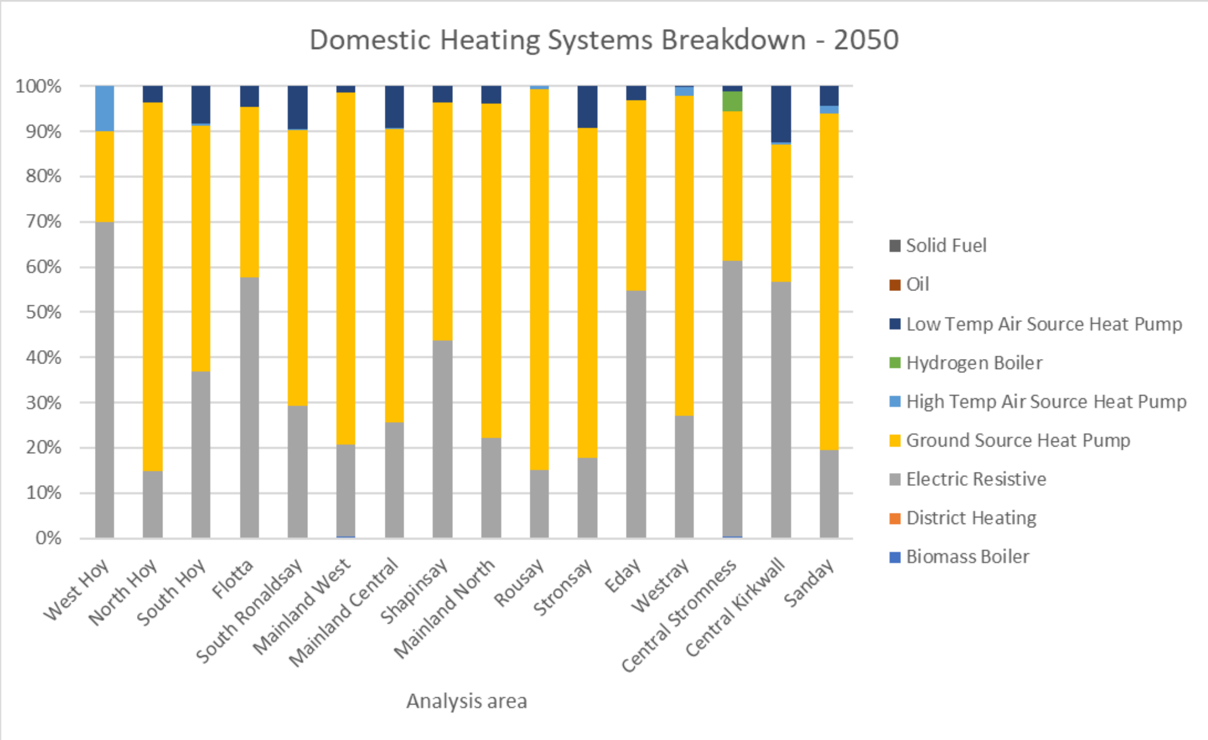

Figure 56 – Domestic heating systems, scenario 2

In this scenario two areas have implemented advanced insulations measures in over half of properties (Figure 57), which is less than in both previous scenarios.

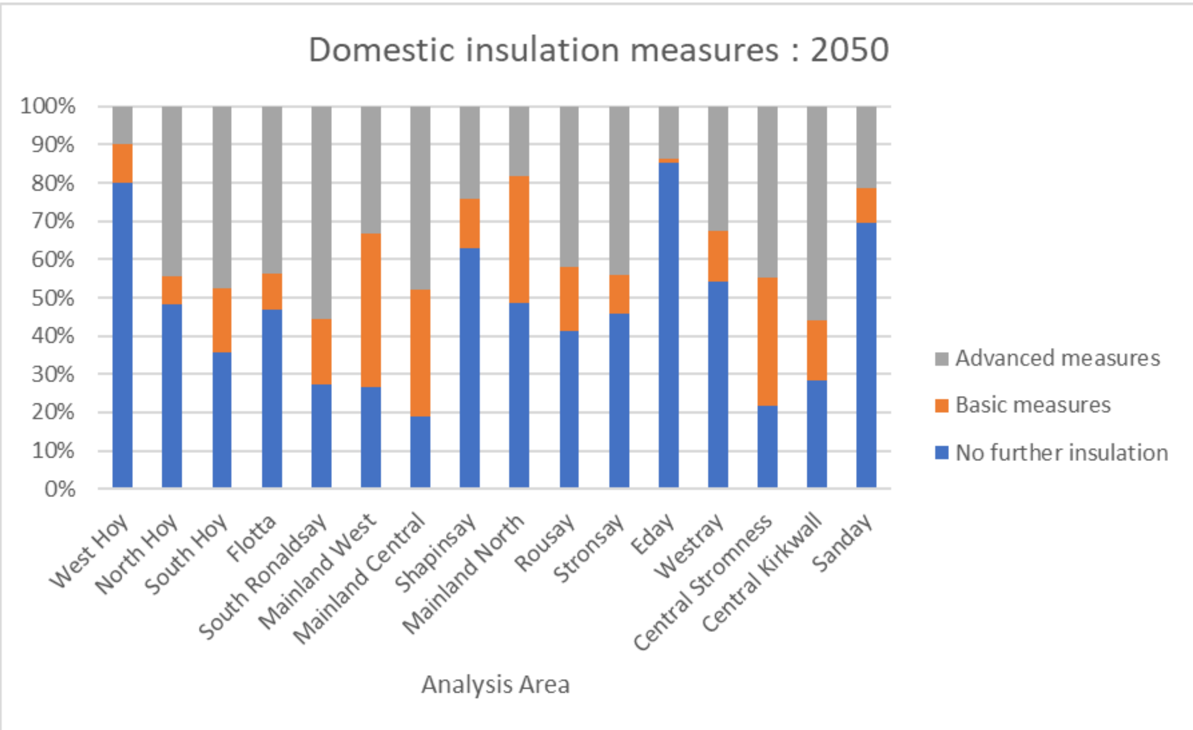

Figure 57 – Domestic insulation, scenario 2

There is a small change in non-domestic heating systems with the installation of the ITEG unit in this scenario (Figure 58). Some oil heating in non-domestic buildings is displaced by hydrogen in Shapinsay. In other areas the model prefers to use hydrogen in non-domestic premises.

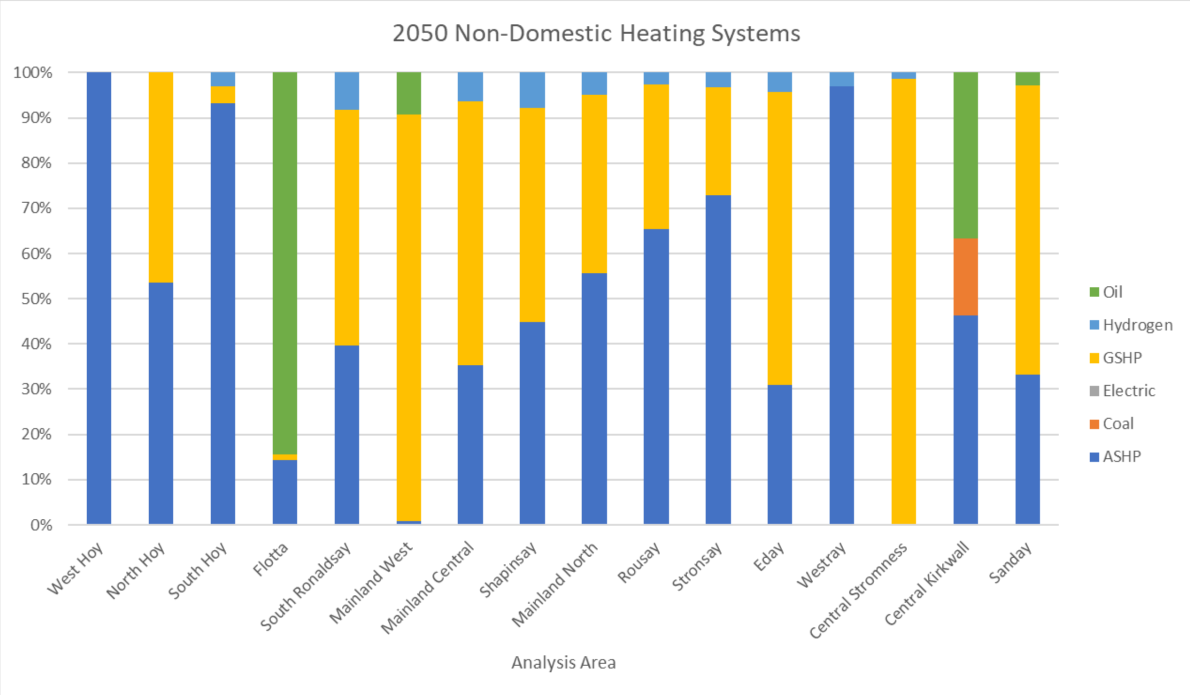

Figure 58 – Non-domestic heating systems, scenario 2

Figure 59 shows the changes of primary energy over time. The ITEG project is small compared with the scale of the whole Orkney energy system so the impact is limited but is visible as a contribution from tidal generation to the primary energy supply. By 2050, carbon emissions within the scope of the model are 3.53 ktCO_2/year.

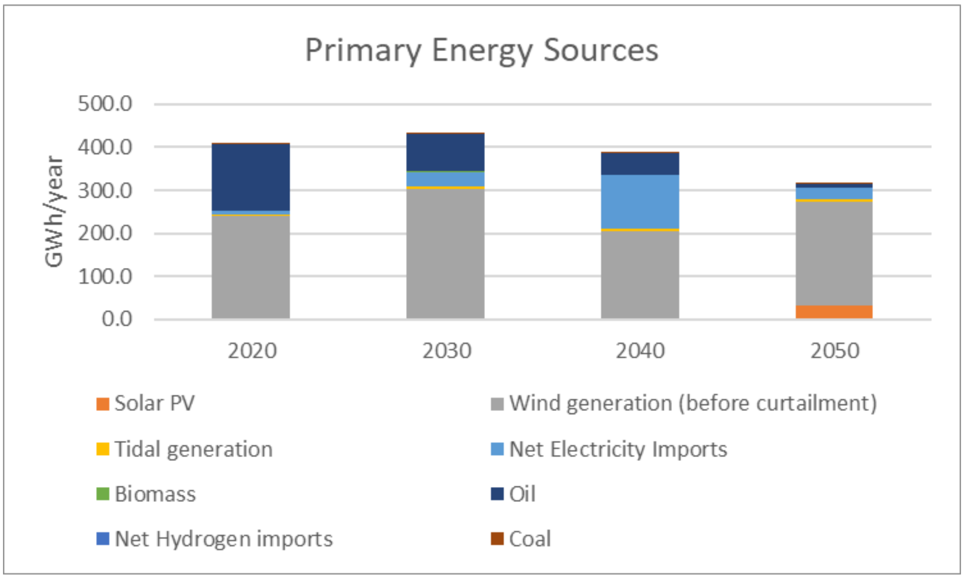

Figure 59 – Primary energy sources, scenario 2

8.4 Scenario 3: Scaled Up ITEG Technologies

In this scenario the ITEG solution is scaled up and offered for installation in additional locations as well as the Eday site.

At the scale offered in this scenario, hydrogen can displace all the oil burning in both domestic premises (Figure 60) and non-domestic properties (Figure 61).

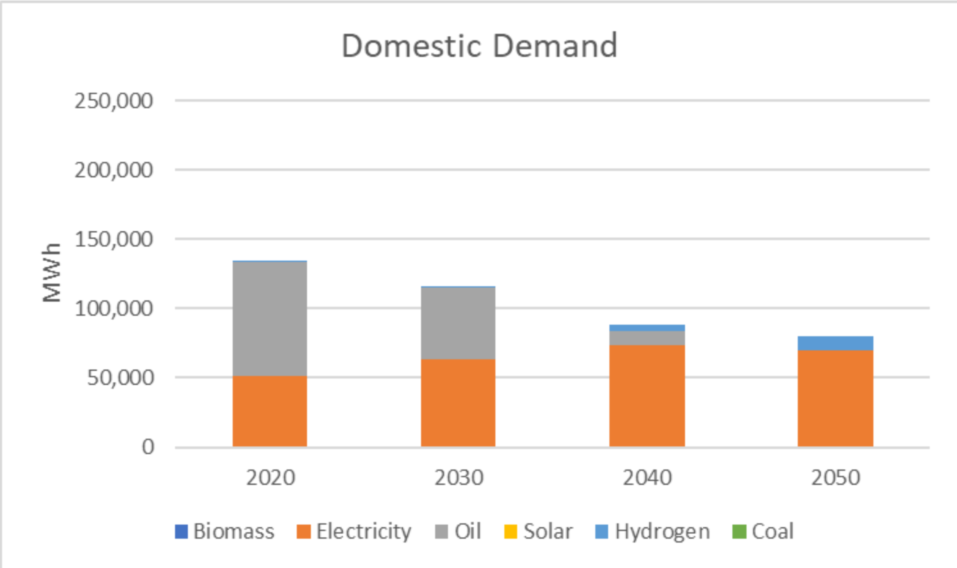

Figure 60 – Domestic demand, scenario 3

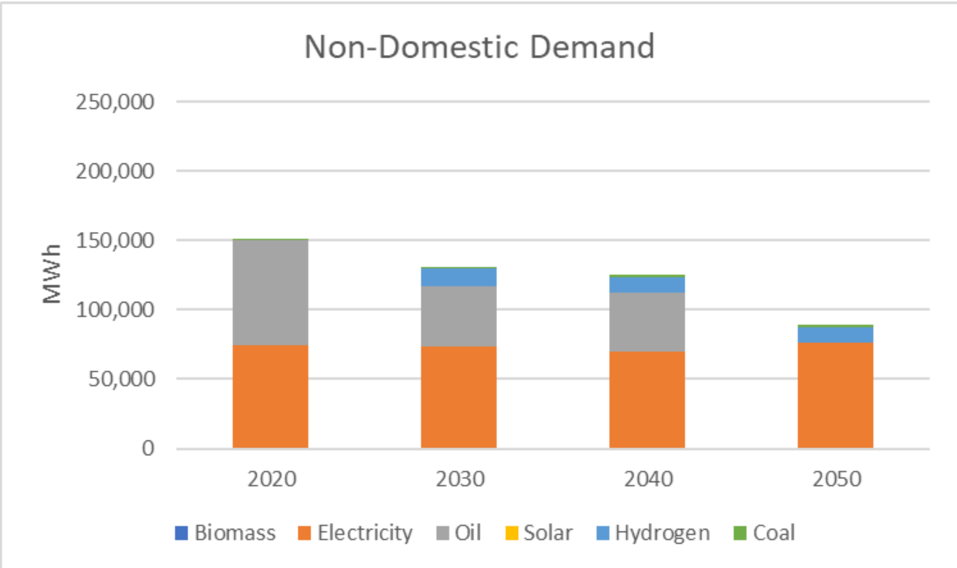

Figure 61 – Non-domestic demand, scenario 3

Figure 62 shows domestic heating system by analysis area. The hydrogen boilers are confined to the central areas of Stromness and Kirkwall. In terms of absolute numbers, there are roughly 1.5 as many hydrogen boilers in central Kirkwall as in central Stromness but there are four times as many properties in the former, resulting in a lower proportion of the total energy mix.

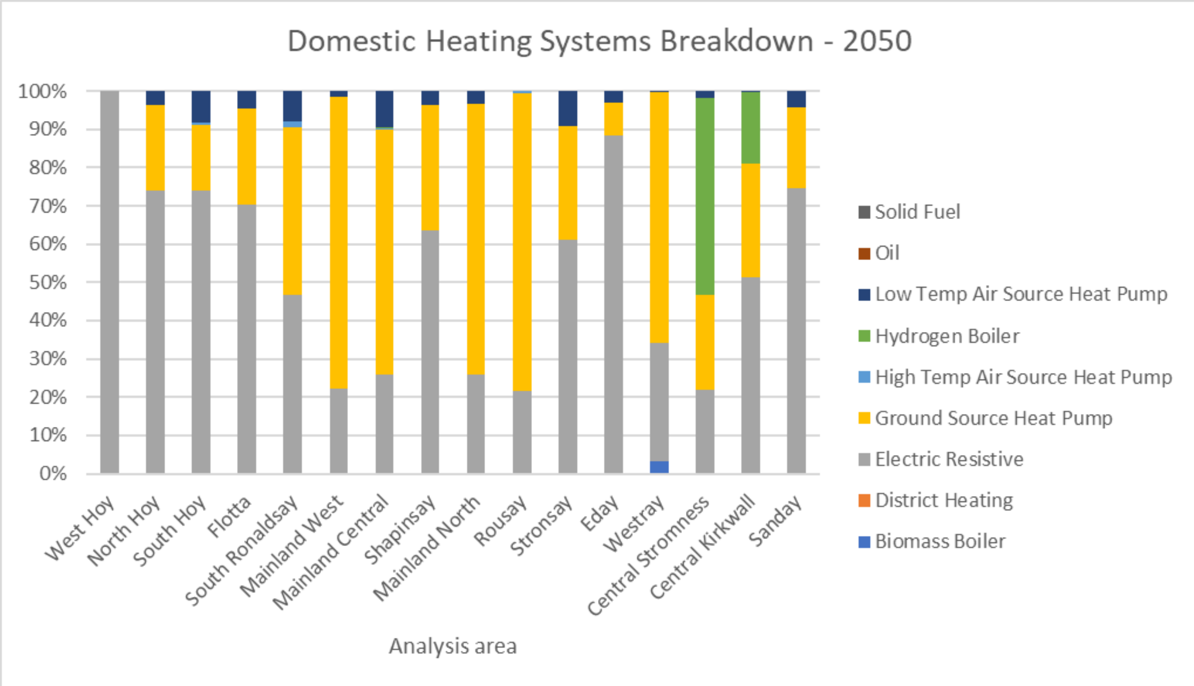

Figure 62 – Domestic heating systems, scenario 3

More domestic insulation measures are implemented in this scenario (Figure 63) but the impact is uneven across the islands. In contrast to previous scenarios, central Kirkwall and central Stromness have relatively low take-up of advanced insulation whereas in the outer islands of Rousay and Westray 70% of properties have such measures.

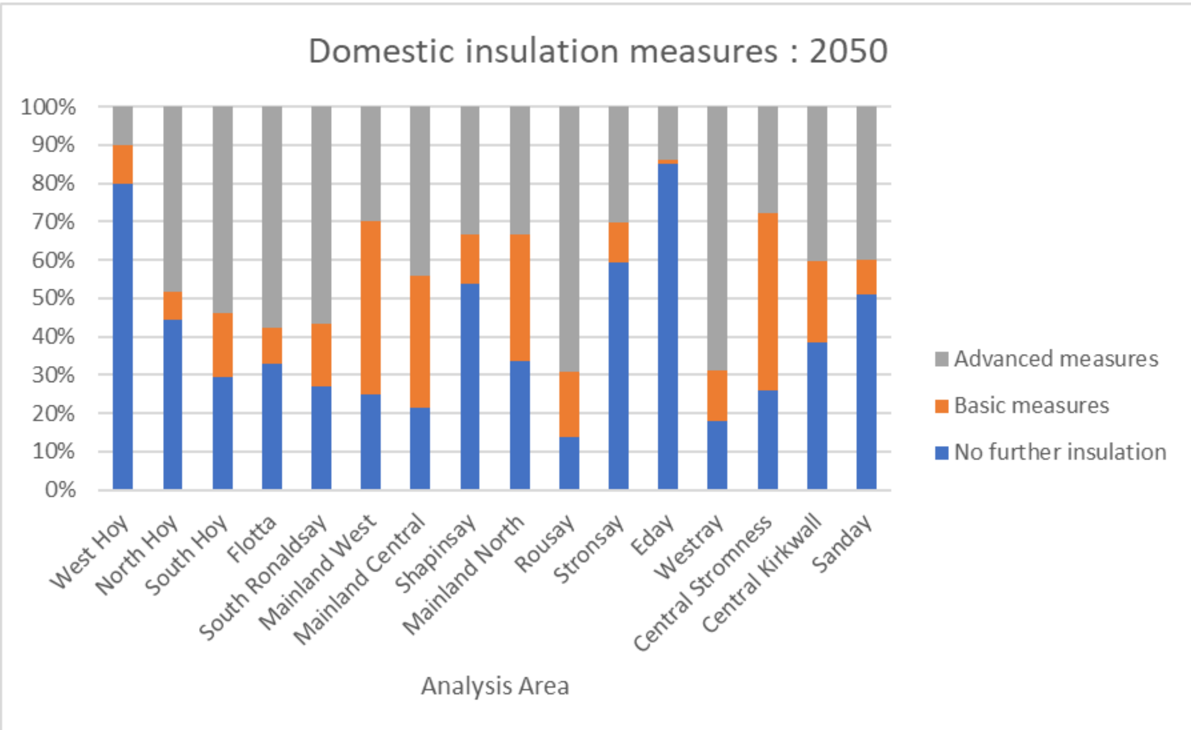

Figure 63 – Domestic insulation, scenario 3

In this scenario oil is no longer used anywhere for non-domestic heating (Figure 64), being replaced mostly by heat pumps with the exception of Flotta where hydrogen is the main source.

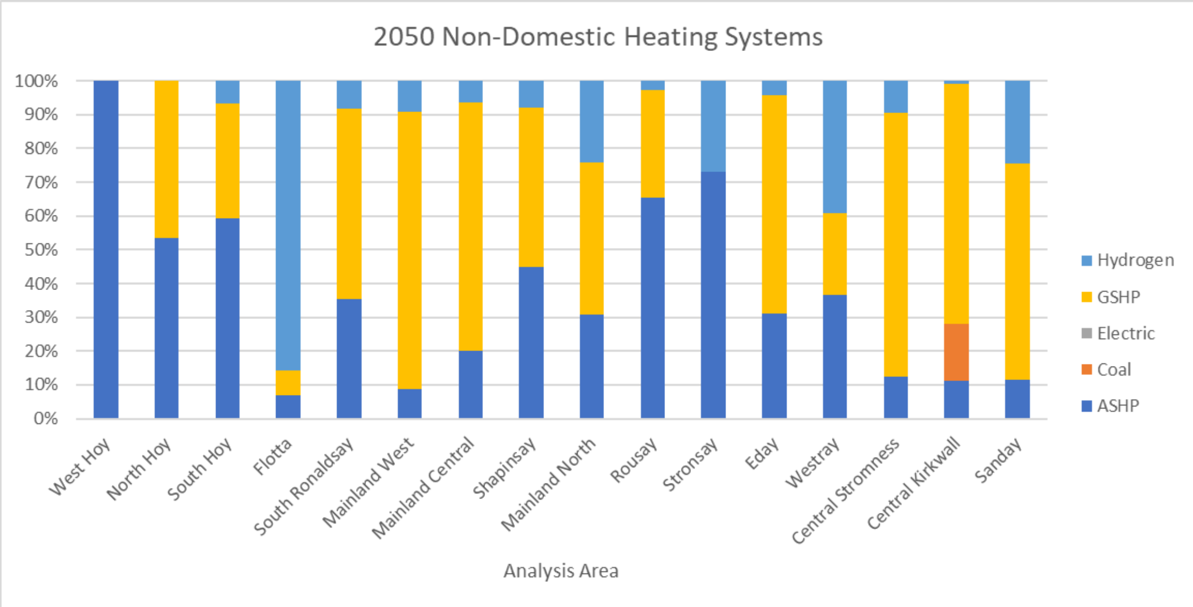

Figure 64 – Non-domestic heating systems, scenario 3

Figure 65 shows the changes of primary energy over time. The additional availability of hydrogen production facilities allows the displacement of all oil use in both domestic and non-domestic properties by hydrogen. The increase in tidal generation not only displaces some wind generation but also enables Orkney to be a net exporter of electricity. By 2050, carbon emissions within the scope of the model are just under 0.55 ktCO_2/year.

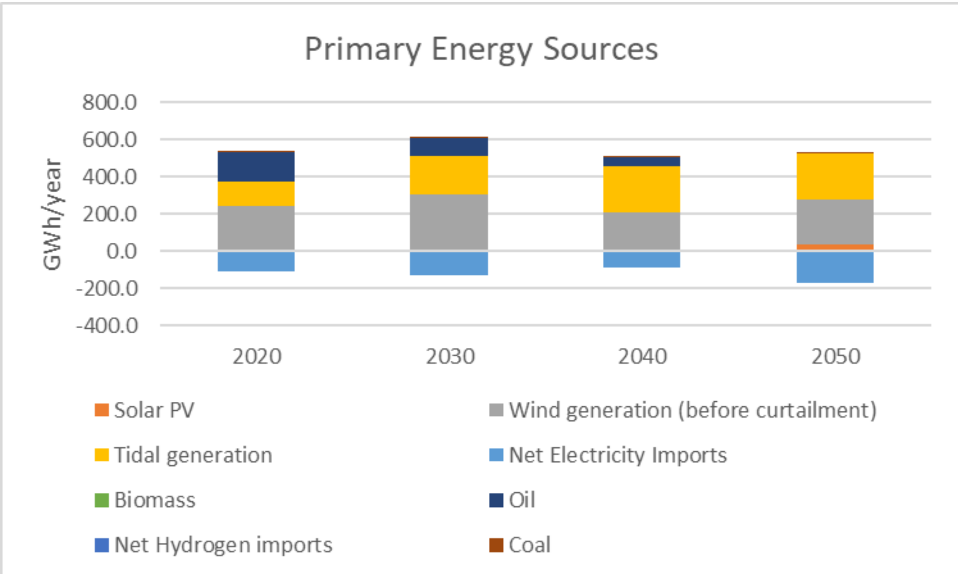

Figure 65 – Primary energy sources, scenario 3

8.5 Scenario 4: Scaled Up ITEG Technologies Uncoupled

As in the previous scenario, hydrogen can displace all the oil burning in both domestic premises (Figure 66) and non-domestic properties (Figure 67).

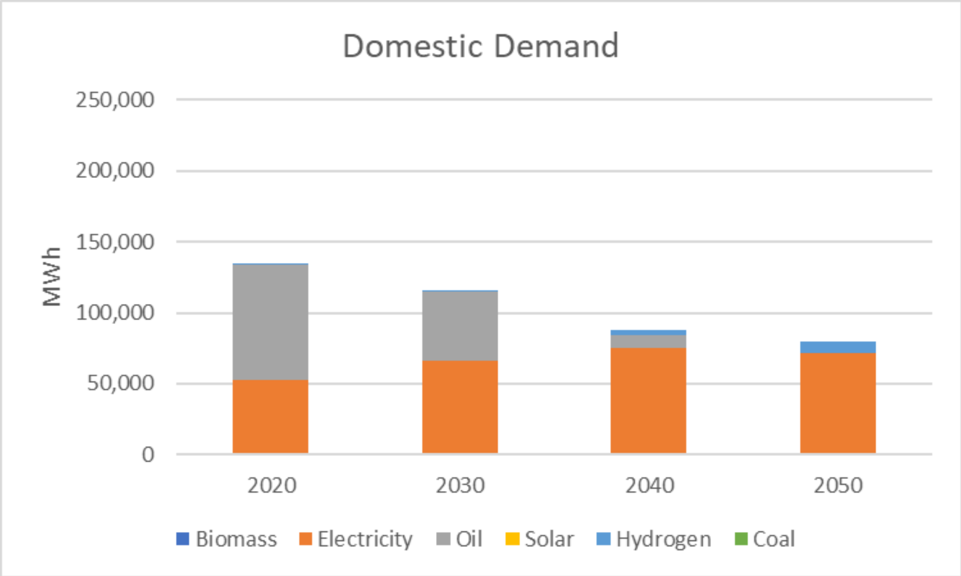

Figure 66 – Domestic demand, scenario 4

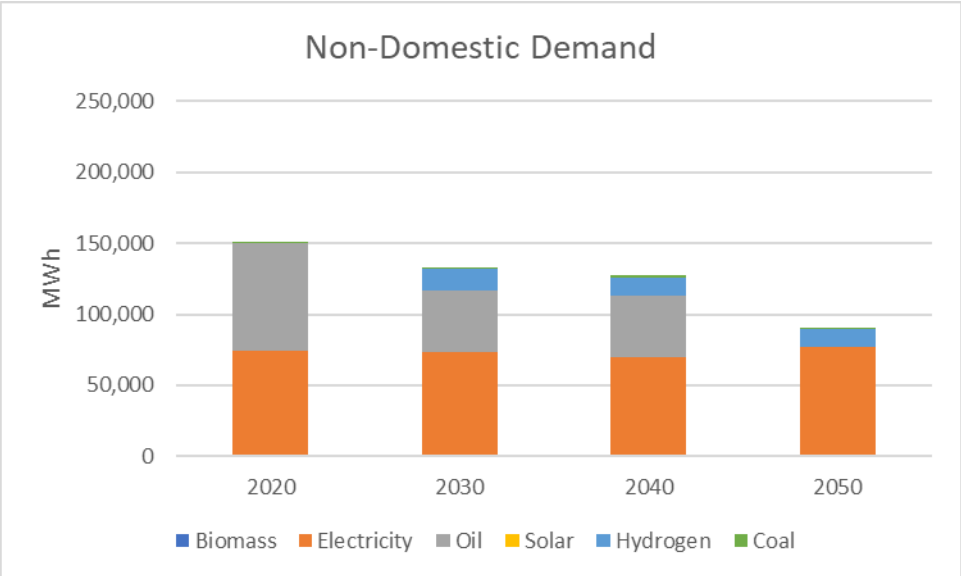

Figure 67 – Non-domestic demand, scenario 4

Figure 68 shows domestic heating system by analysis area. As in Scenario 3, the hydrogen boilers are confined to the central areas of Stromness and Kirkwall. There is a more widespread uptake of high temperature air source heat pumps, with the greatest number installed on Westray.

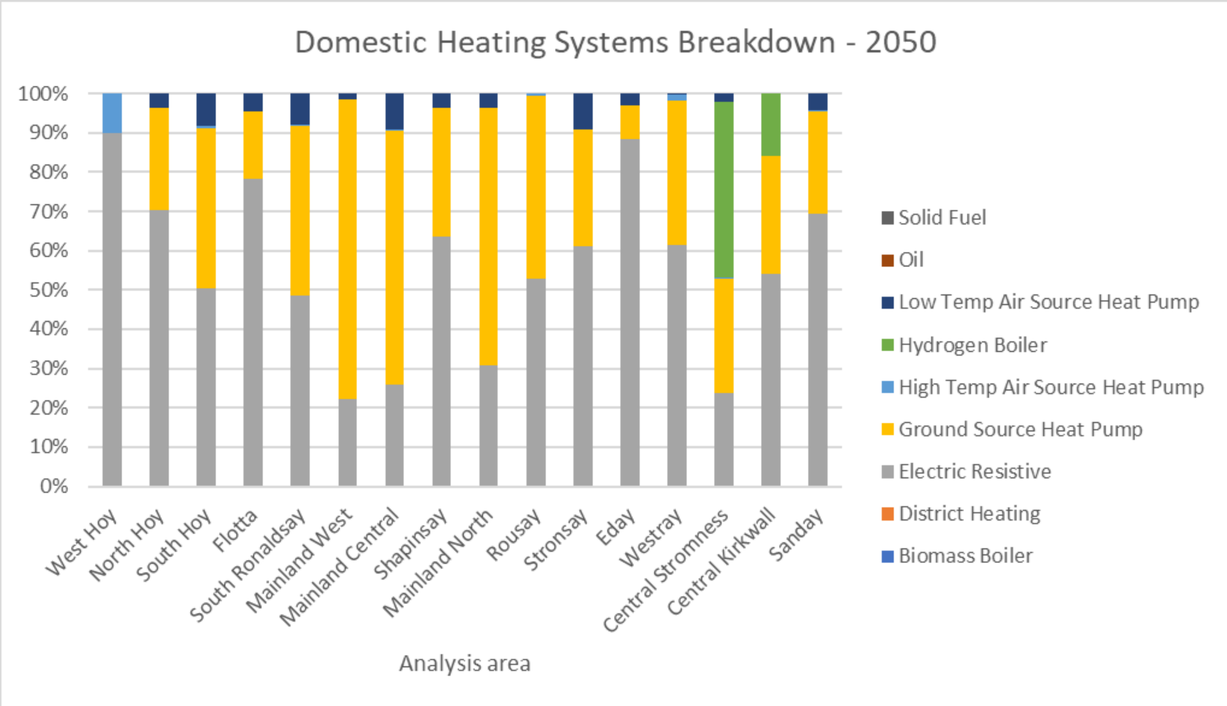

Figure 68 – Domestic heating systems, scenario 4

Even more domestic insulation measures are implemented in this scenario (Figure 69) with Flotta and South Hoy moving above the 50% threshold.

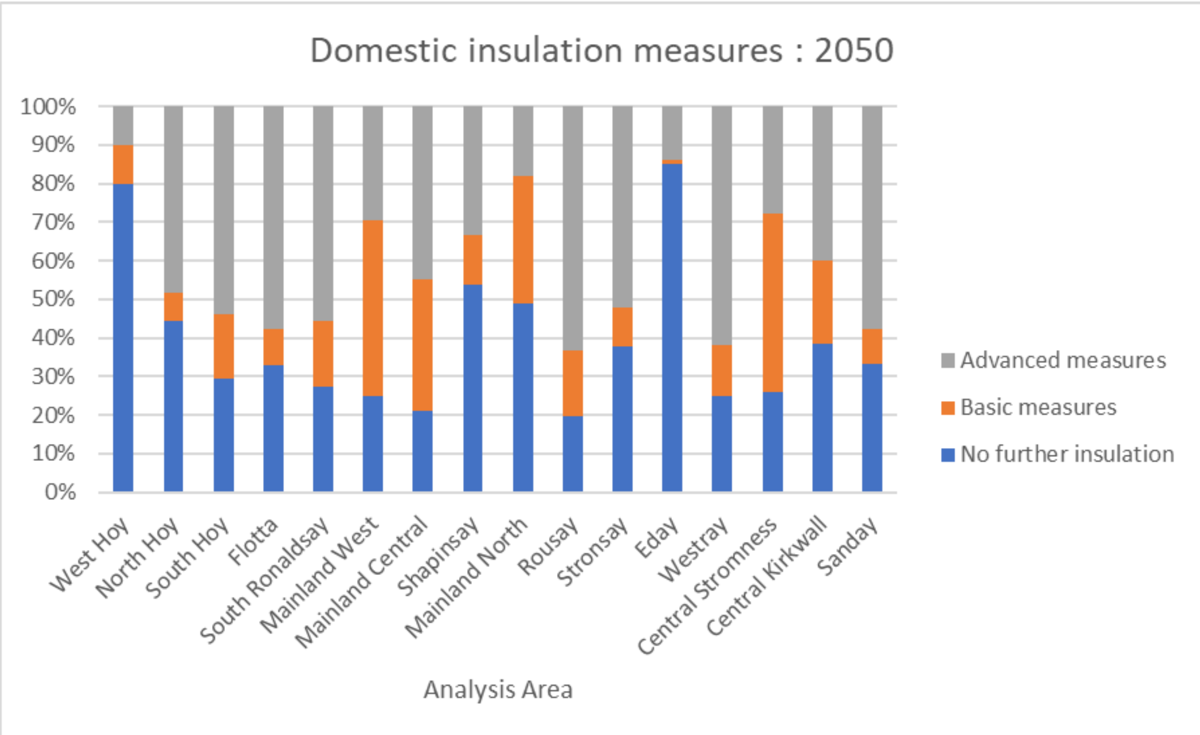

Figure 69 – Domestic insulation, scenario 4

In non-domestic buildings oil has been completely replaced, mostly by heat pumps but also by hydrogen in all areas apart from West and North Hoy.

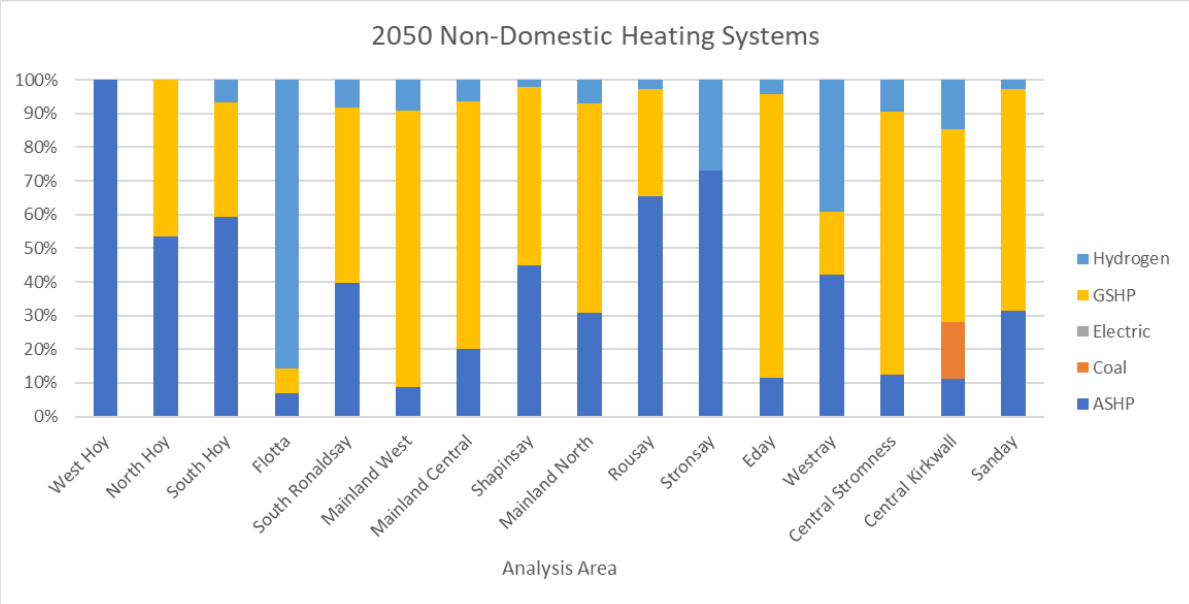

Figure 70 – Non-domestic heating systems, scenario 4

Figure 71 shows the changes of primary energy over time. The additional availability of hydrogen production facilities allows the displacement of all oil use in both domestic and non-domestic properties. The tidal generation not only displaces some wind generation but also enables electricity to be exported. By 2050, carbon emissions within the scope of the model are just under 0.51 ktCO_2/year.

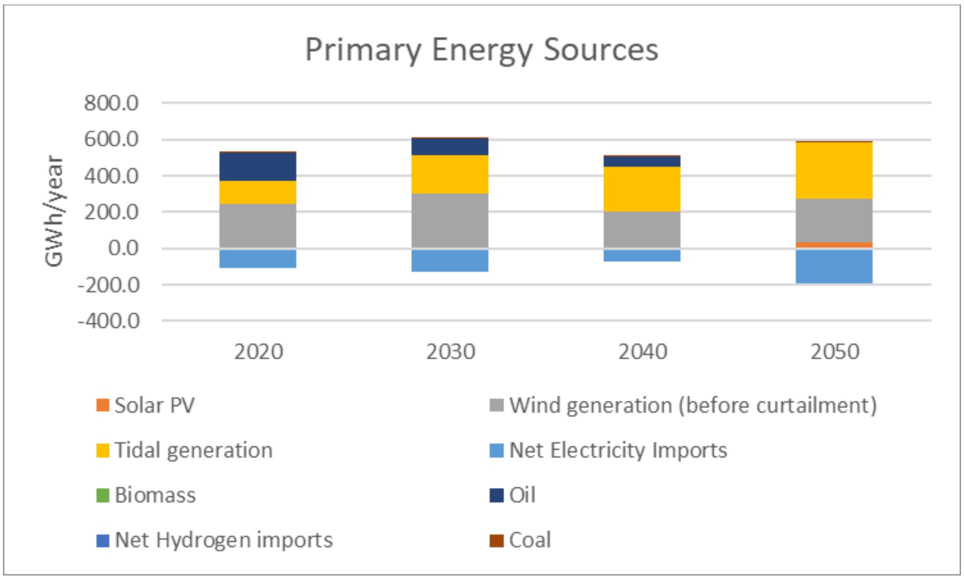

Figure 71 – Primary Energy Sources, scenario 4

8.6 Scenario 5: Further Hydrogen System

In this scenario, additional fuel cells are offered to the model for installation in a variety of locations. The scaled-up ITEG solution is also in place.

With more hydrogen available, in more locations, the model is able to replace all the domestic oil burning (Figure 72) and non-domestic oil use (Figure 73).

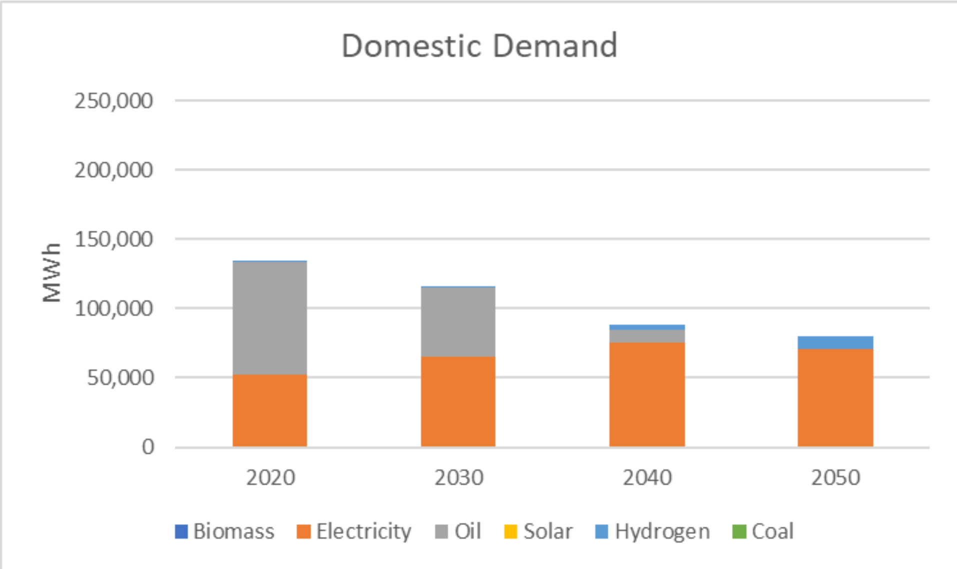

Figure 72 – Domestic demand, scenario 5

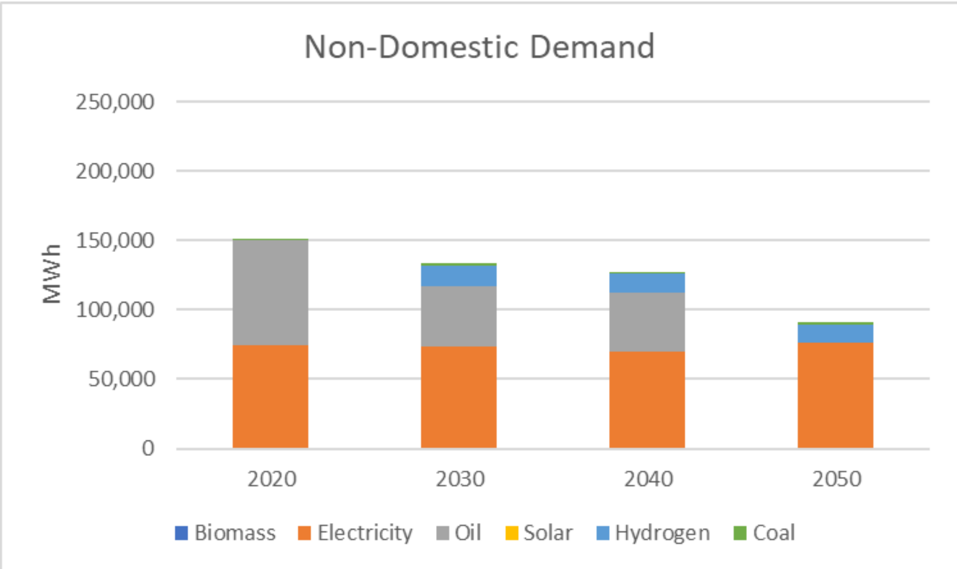

Figure 73 – Non-domestic demand, Scenario 5

Conversion to hydrogen boilers (Figure 74) is focussed on the central areas of Kirkwall Stromness. Interestingly, in this scenario the domestic properties on Shapinsay formerly using oil are converted to ground source heat pumps or electric heating rather than hydrogen boilers.

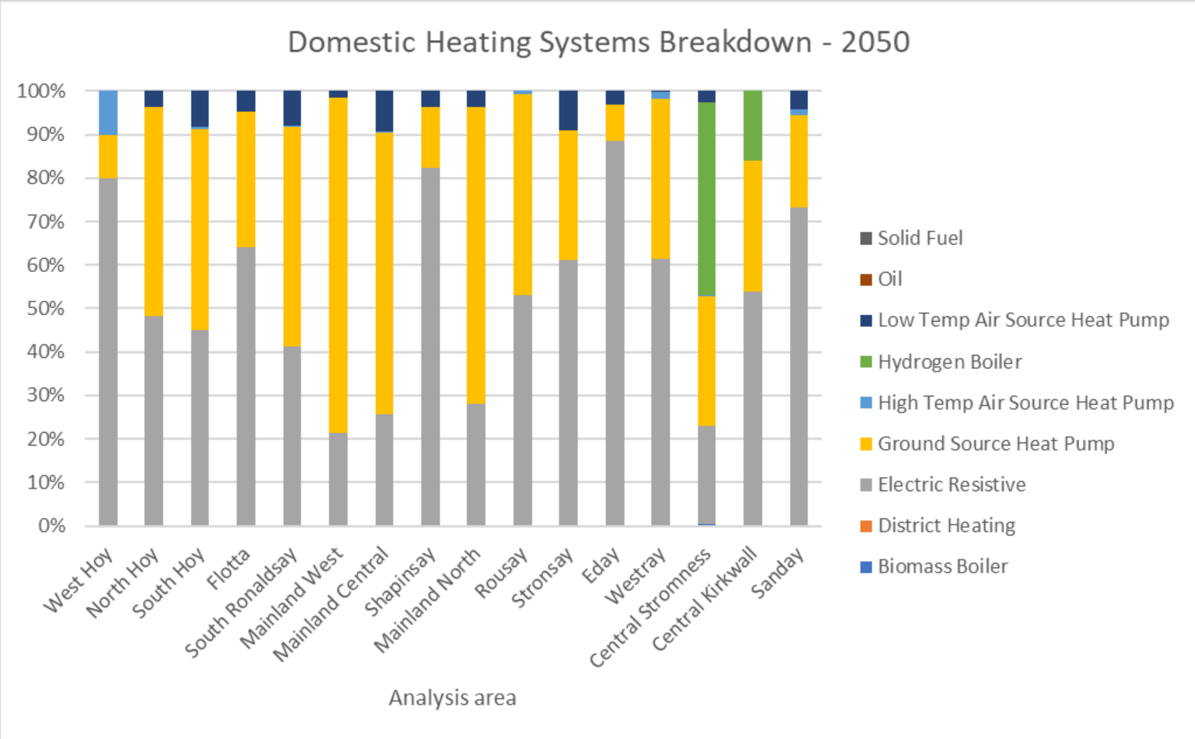

Figure 74 – Domestic heating systems, scenario 5

Compared to Scenario 3, there is reduced uptake of insulation measures on Orkney Mainland away from the urban areas of Stromness and Kirkwall (Figure 75).

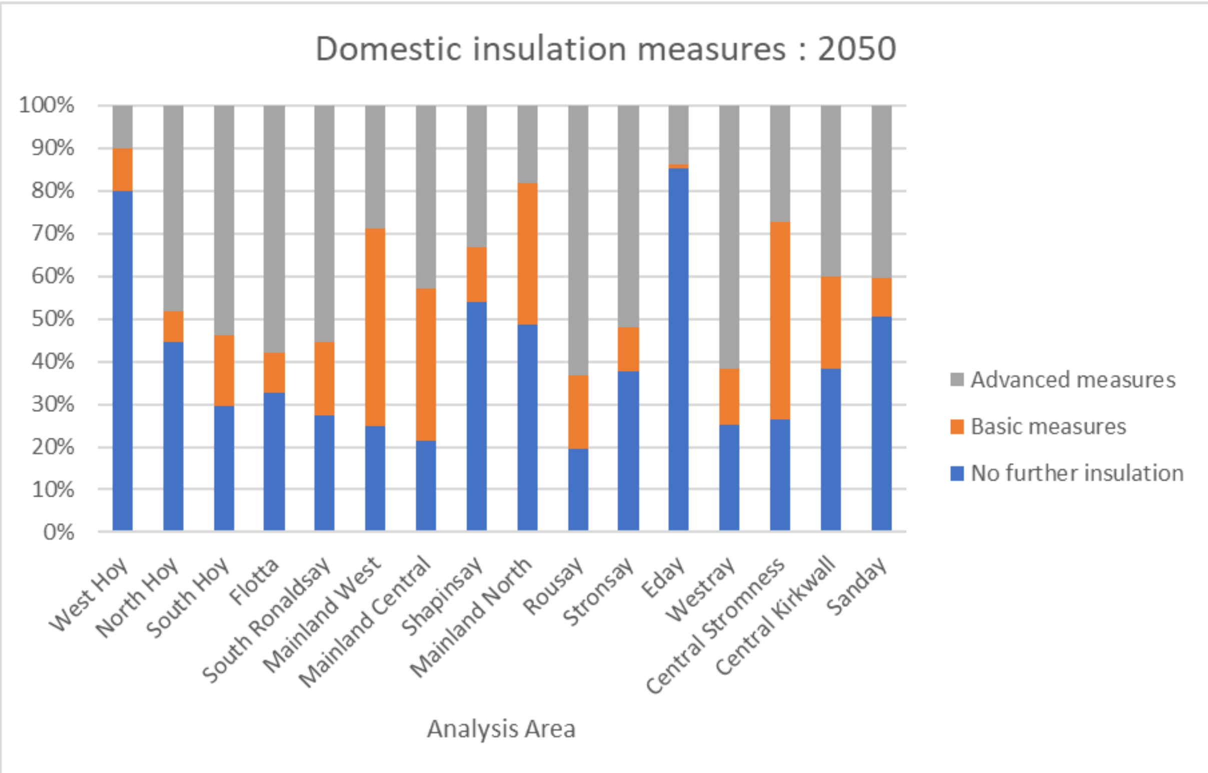

Figure 75 – Domestic insulation, scenario 5

Non-domestic building heating systems in this scenario are shown in Figure 76.

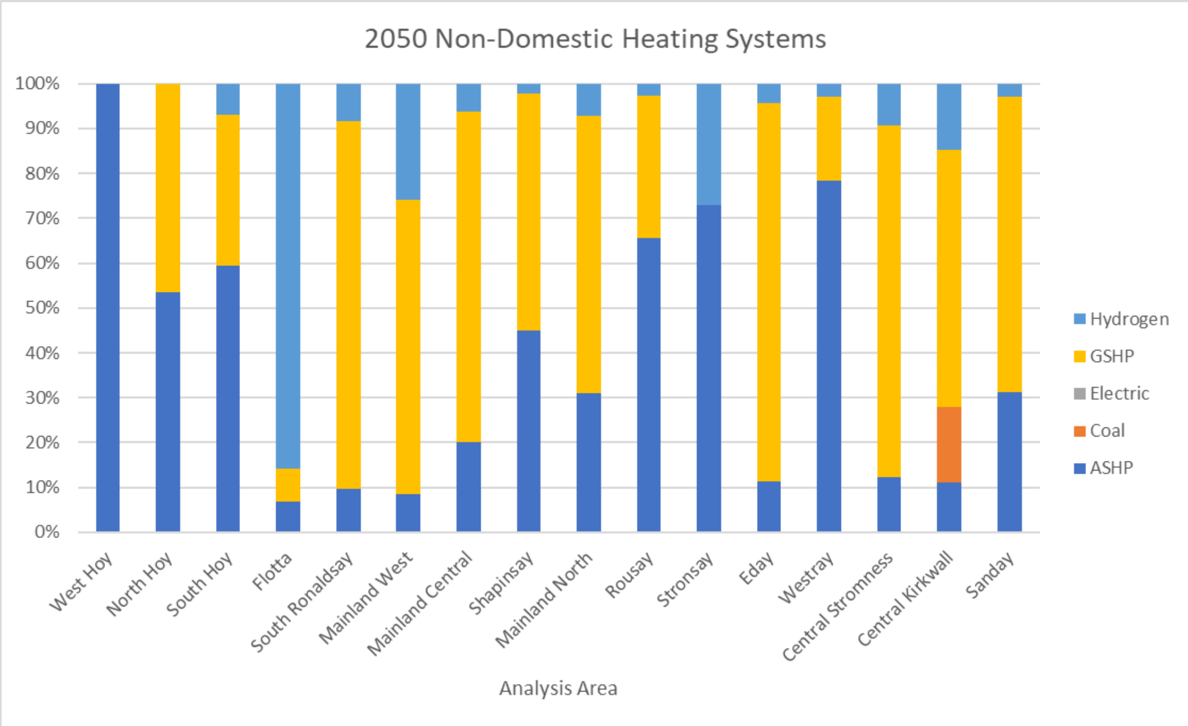

Figure 76 – Non-domestic heating systems, scenario 5

Figure 77 shows the changes of primary energy over time. The additional availability of hydrogen production facilities allows the displacement of all oil use in both domestic and non-domestic properties. The tidal generation not only displaces some wind generation but also enables electricity to be exported. By 2050, carbon emissions within the scope of the model are just under 0.51 $ktCO_2$/year, as in Scenario 4.

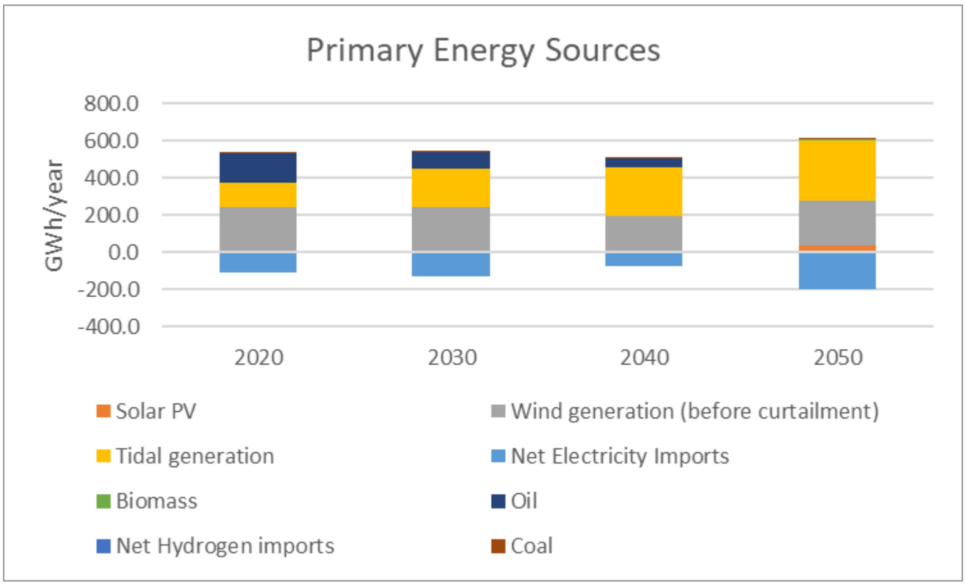

Figure 77 – Primary energy sources, scenario 5

8.7 Scenario 6: Connected Hydrogen

In this scenario electric heating and hydrogen is able to replace oil in all domestic and non-domestic building (Figure 78 & Figure 79).

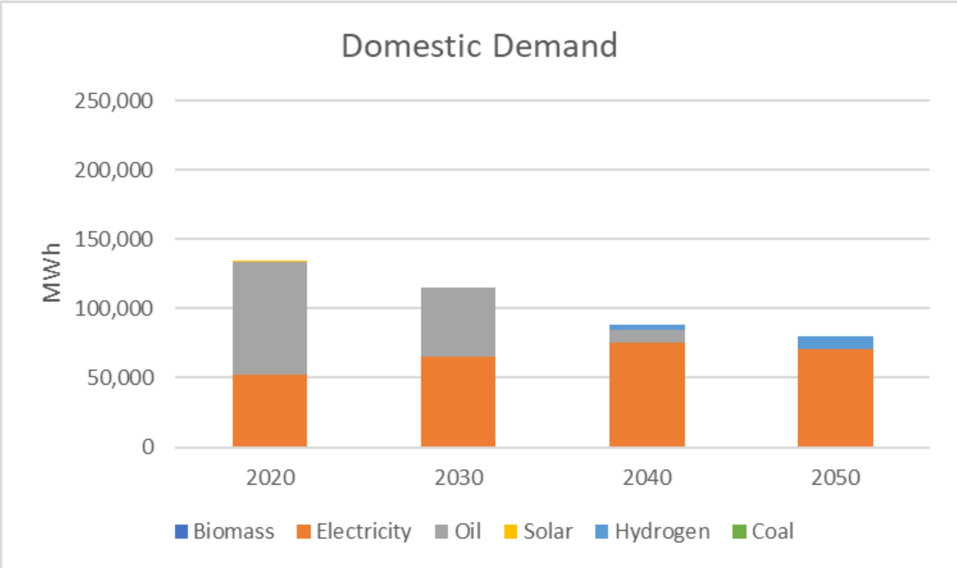

Figure 78 – Domestic Demand, scenario 6

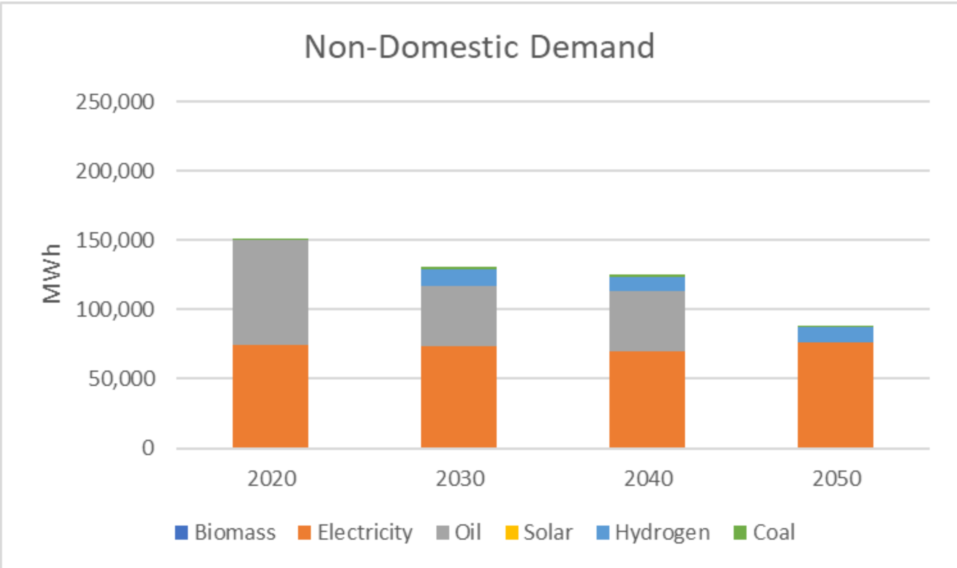

Figure 79 – Non-domestic demand, scenario 6

As in scenario 5, oil-fired heating is replaced by electric heating and heat pumps with the former dominating the energy mix (Figure 80). Despite the greater availability of hydrogen, it is only used as a source of domestic heating in central Stromness and Kirkwall.

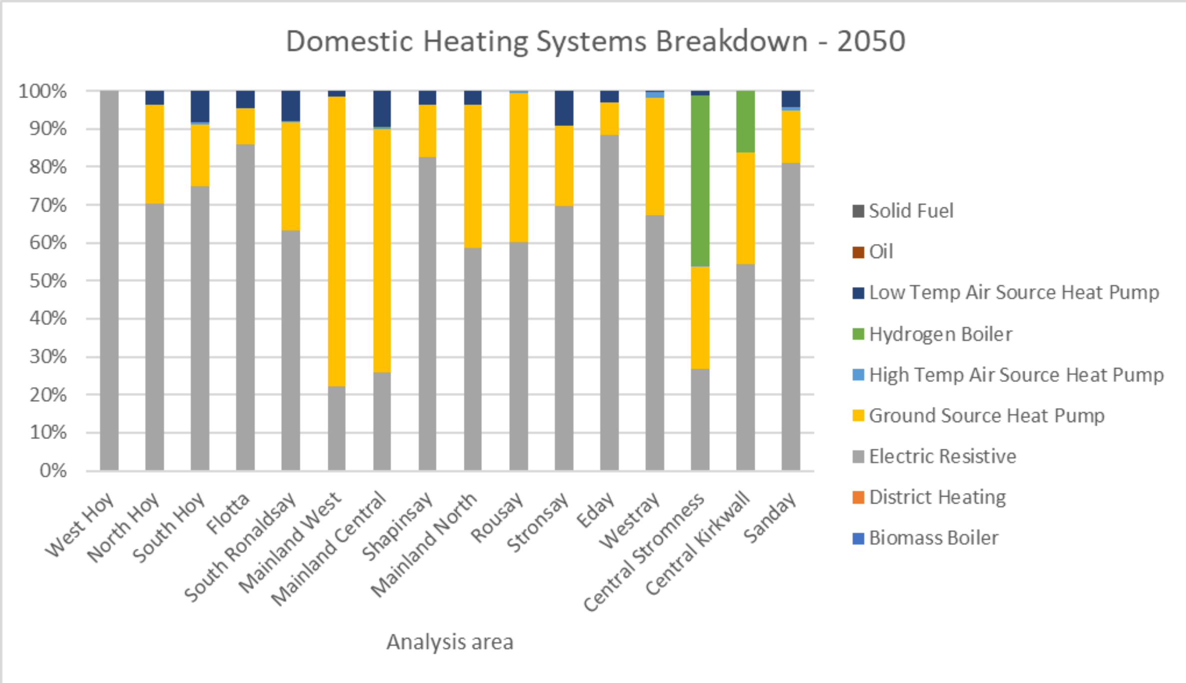

Figure 80 – Domestic heating systems, scenario 6

Take up of domestic insulation is less widespread than in the previous scenarios. In only two areas (South Ronaldsay and Westray) are more than half the properties insulated to advanced levels (Figure 81).

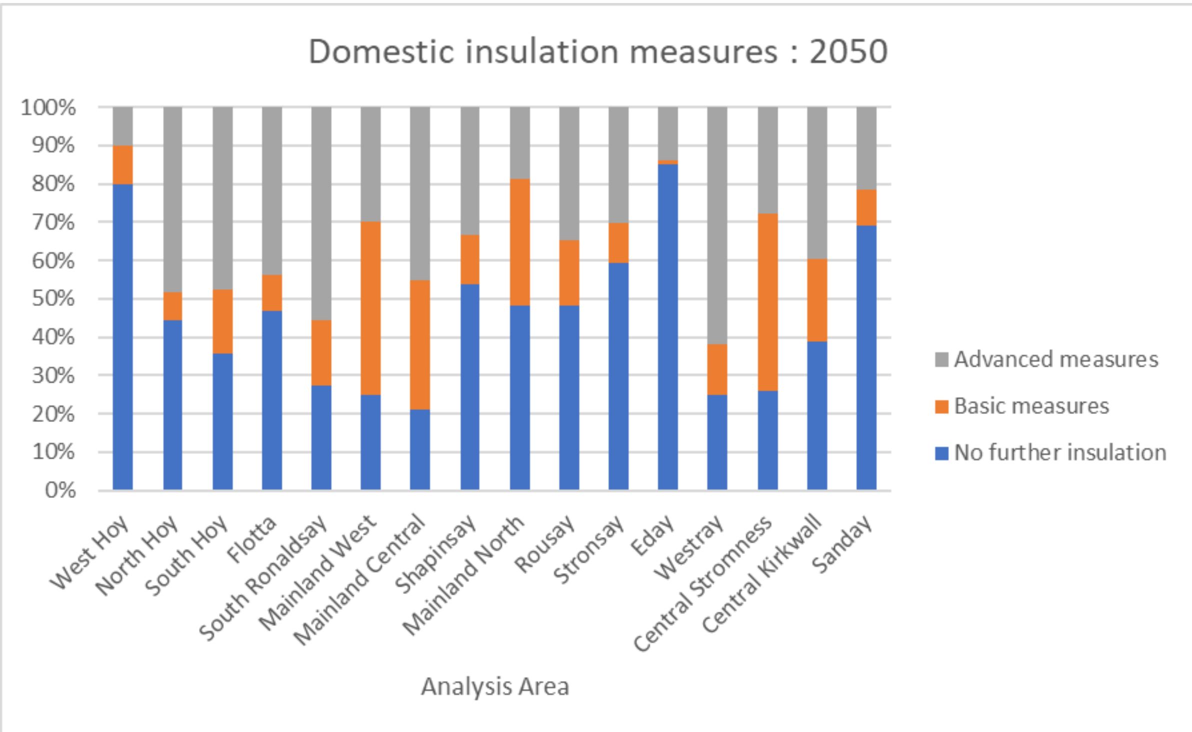

Figure 81 – Domestic insulation, scenario 6

The energy mix for non-domestic heating systems is very similar to that of Scenario 4, especially with regards to hydrogen usage (Figure 82). Central Stromness is the only area in which hydrogen usage makes up a bigger proportion of the energy mix than in Scenario 5, as well as being the only area where air source heat pumps are not deployed.

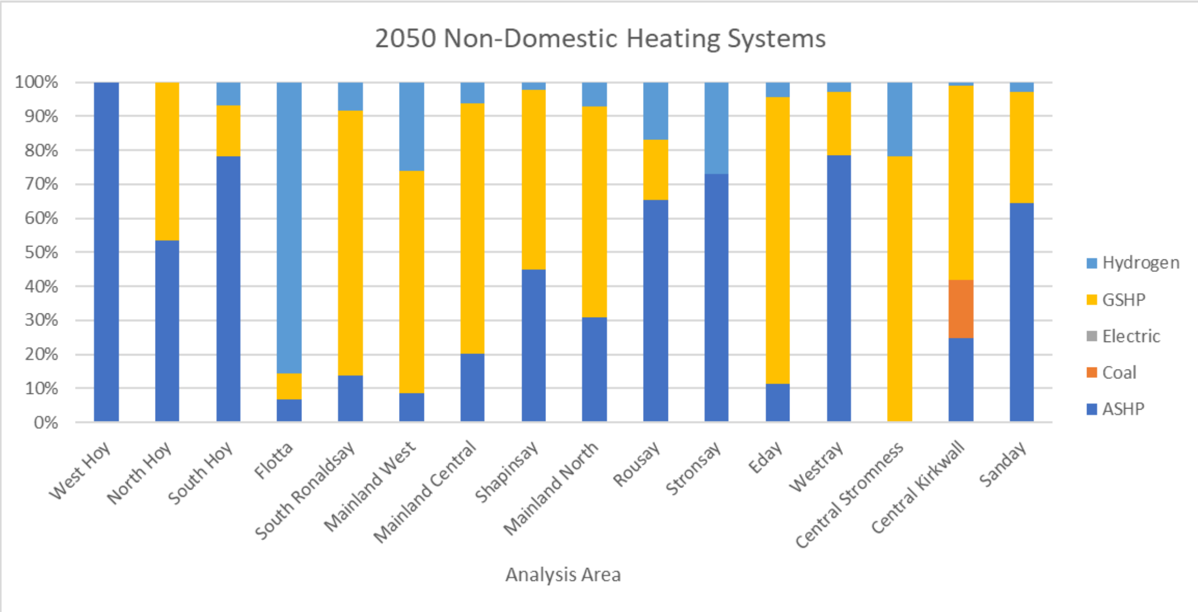

Figure 82 – Non-domestic heating systems, scenario 6

Figure 83 shows the change in primary energy supply over time. Tidal generation makes up an increasing proportion of the energy mix although oil and coal remain in use in 2050, making up 0.1% and 0.4% respectively. By 2050, carbon emissions are 0.57 $ktCO_2$/year.

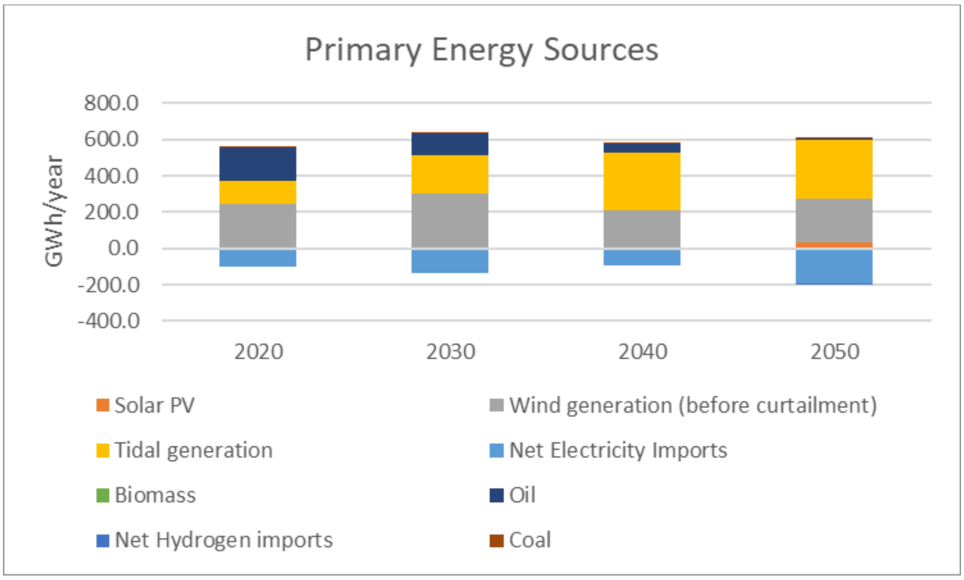

Figure 83 – Primary energy sources, scenario 6

8.8 Scenario 7: Competitive Hydrogen

In this scenario electric heating and hydrogen is able to replace oil in all domestic and non-domestic buildings (Figure 84 & Figure 85).

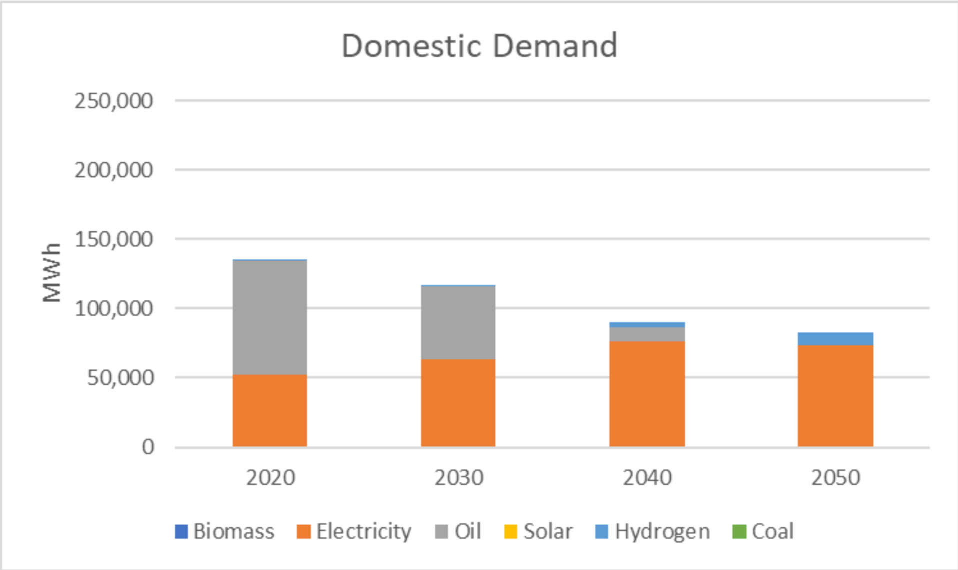

Figure 84 – Domestic demand, scenario 7

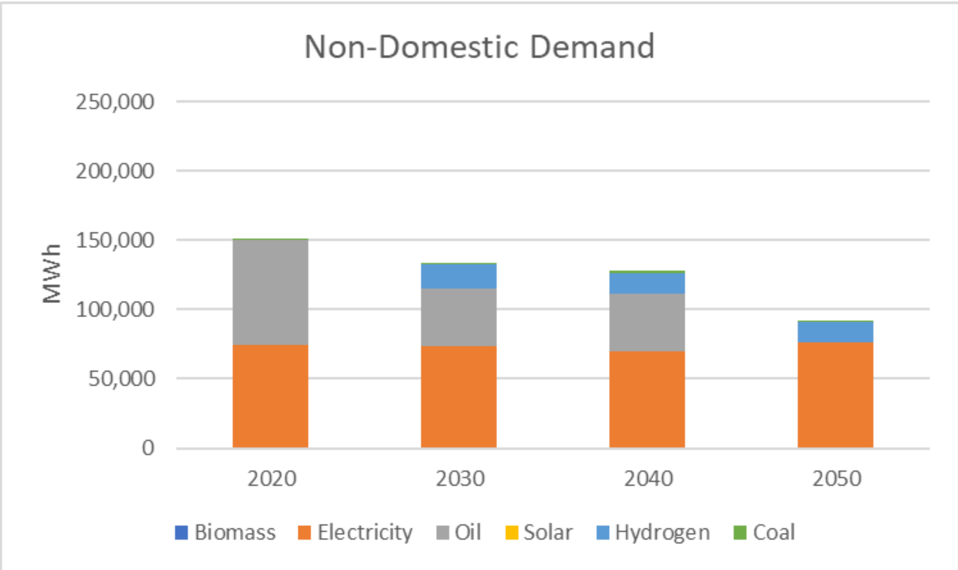

Figure 85 – Non-domestic demand, scenario 7

As in scenario 7, oil-fired heating is replaced by electric heating and heat pumps with slightly more of the former overall (Figure 86). Hydrogen, is only used as a source of domestic heating in central Stromness and Kirkwall.

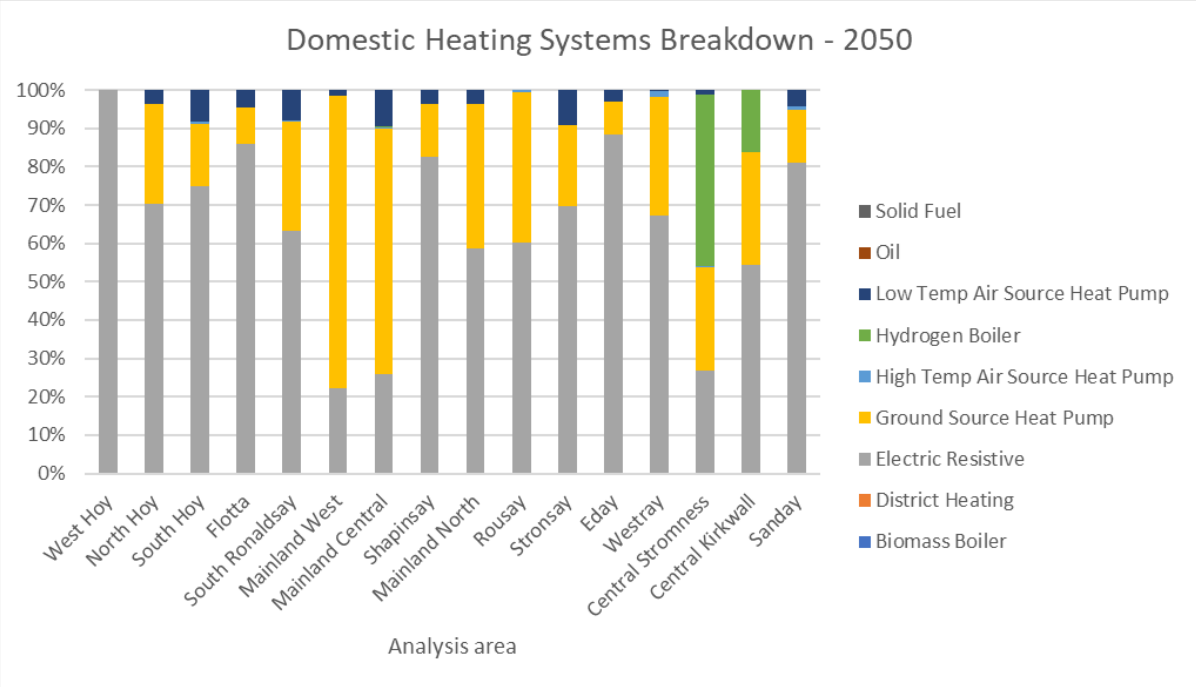

Figure 86 – Domestic heating systems, scenario 7

Domestic insulation uptake (Figure 87) follows a similar pattern to Scenario 1b, in that a lower proportion of homes in the Stromness and Kirkwall urban areas have advanced insulation measures compared the more outlying islands. Fewer homes on Sanday are insulated than in the earlier scenario.

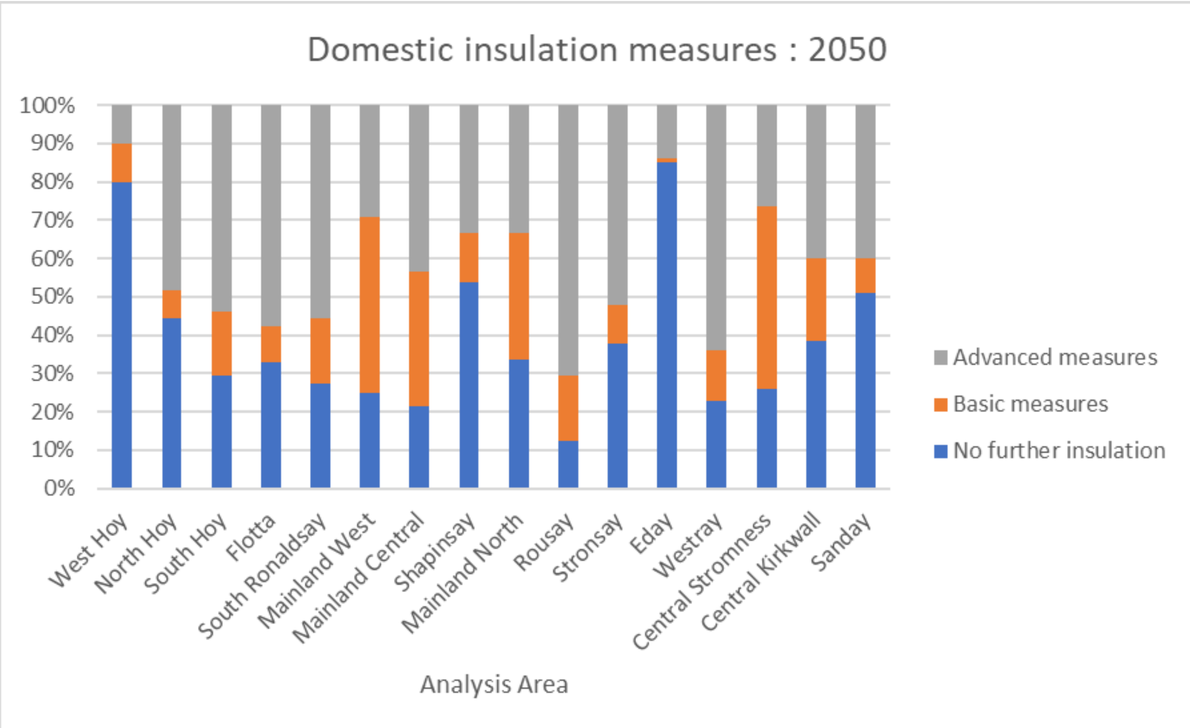

Figure 87 – Domestic insulation, scenario7

The increased usage of hydrogen for non-domestic buildings in Scenario 5 goes even further in this scenario (Figure 88), not least in South Hoy where the tidal technologies utilising the resources of the Pentland Firth are concentrated although it is neighbouring Flotta which has the highest proportion of hydrogen in the energy mix.

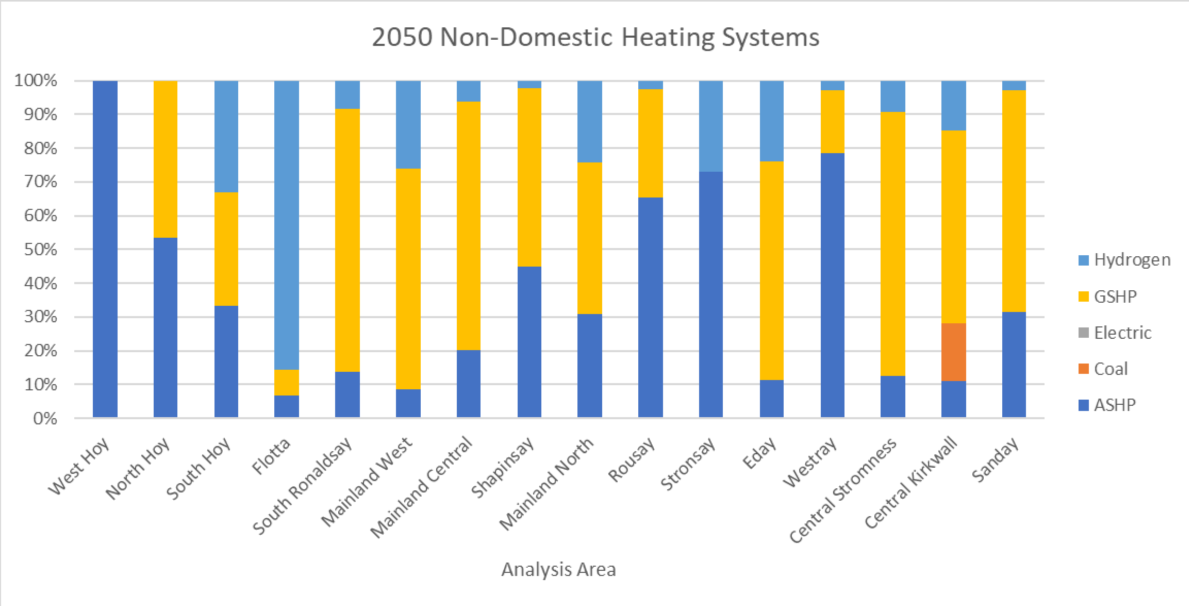

Figure 88 – Non-domestic heating systems, scenario 7

Figure 89 shows the change in primary energy supply over time. The availability of imported hydrogen has the effect of reducing the proportion of wind and tidal generation in the final energy mix. As in Scenario 6, oil is still used in non-domestic buildings in 2050 (making up 0.1% of the energy supply). By 2050, carbon emissions are 0.59ktCO_2/year, higher than for the previous four scenarios.

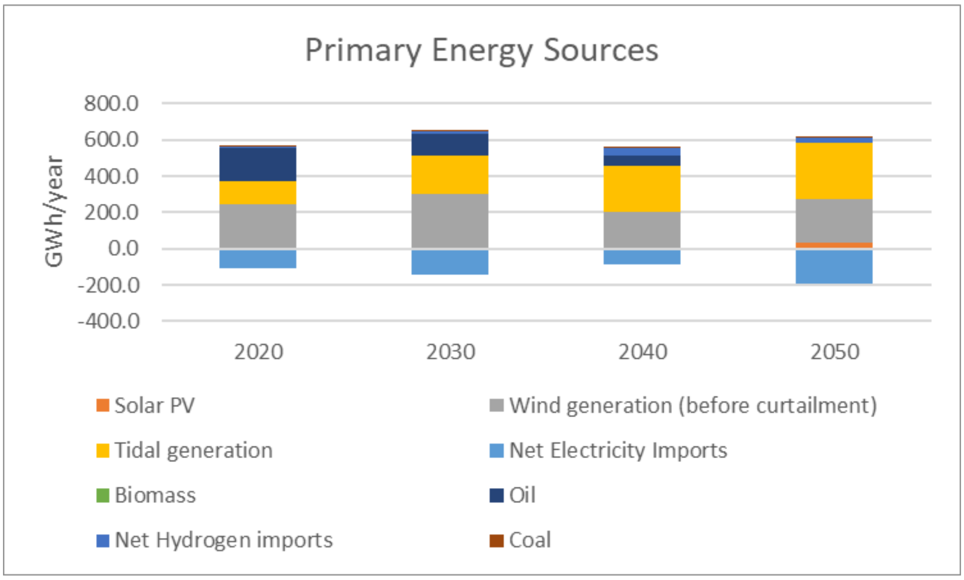

Figure 89 – Primary energy sources, scenario 7

8.9 Scenario 8: Electricity Focus

In this scenario hydrogen and electricity are able to replace all oil consumption for domestic heating (Figure 90), and almost all (59MWh remaining in use in 2050) for non-domestic buildings (Figure 91).

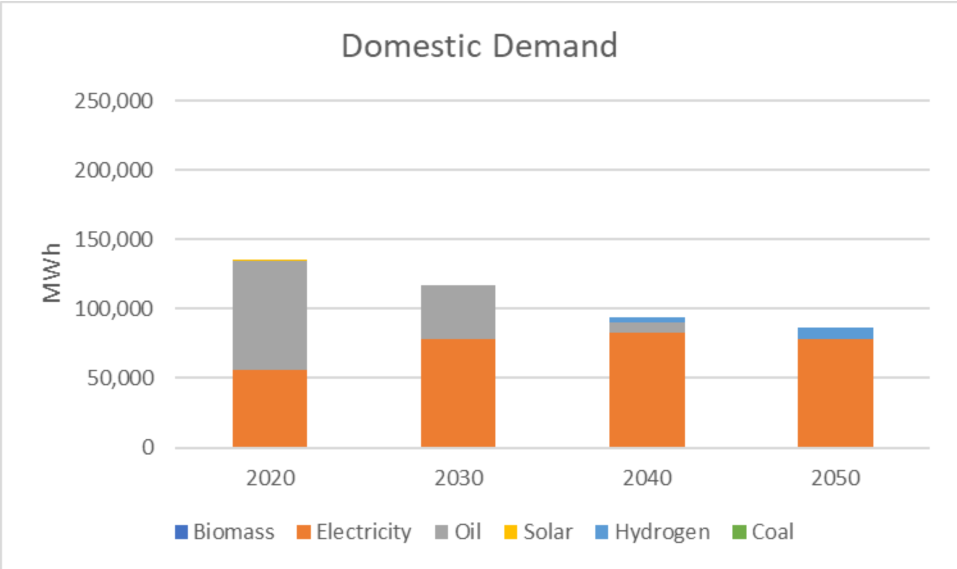

Figure 90 – Domestic demand, scenario 8

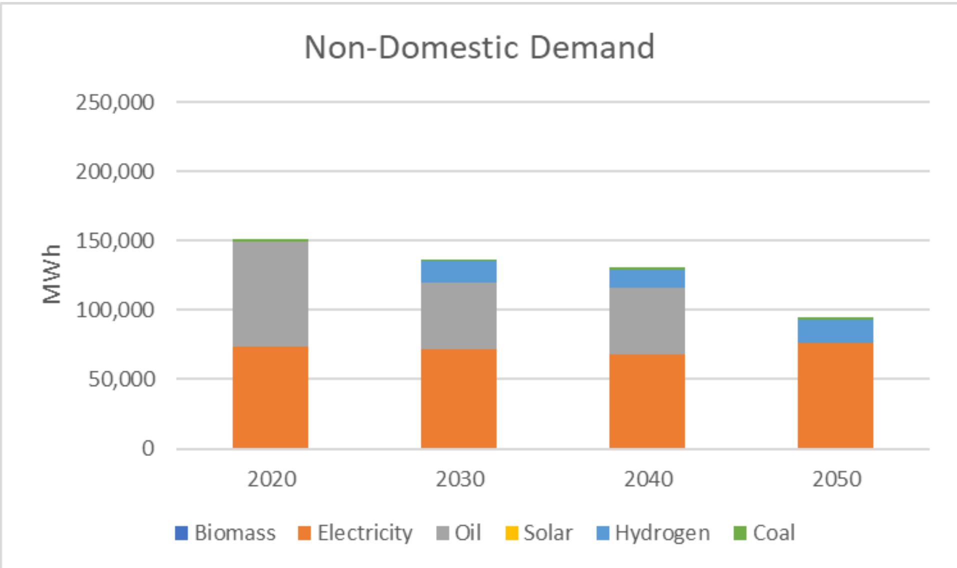

Figure 91 – Non-domestic demand, scenario 8

In contrast to previous scenarios, it is direct electric resistive heating rather than heat pumps which replace oil-fired heating in domestic buildings (Figure 92). This is driven by increased availability of low carbon generation supported by the opportunity to export from Orkney. With such large quantities of renewable electricity available there is less need to invest in more efficient, but more expensive, heat pumps.

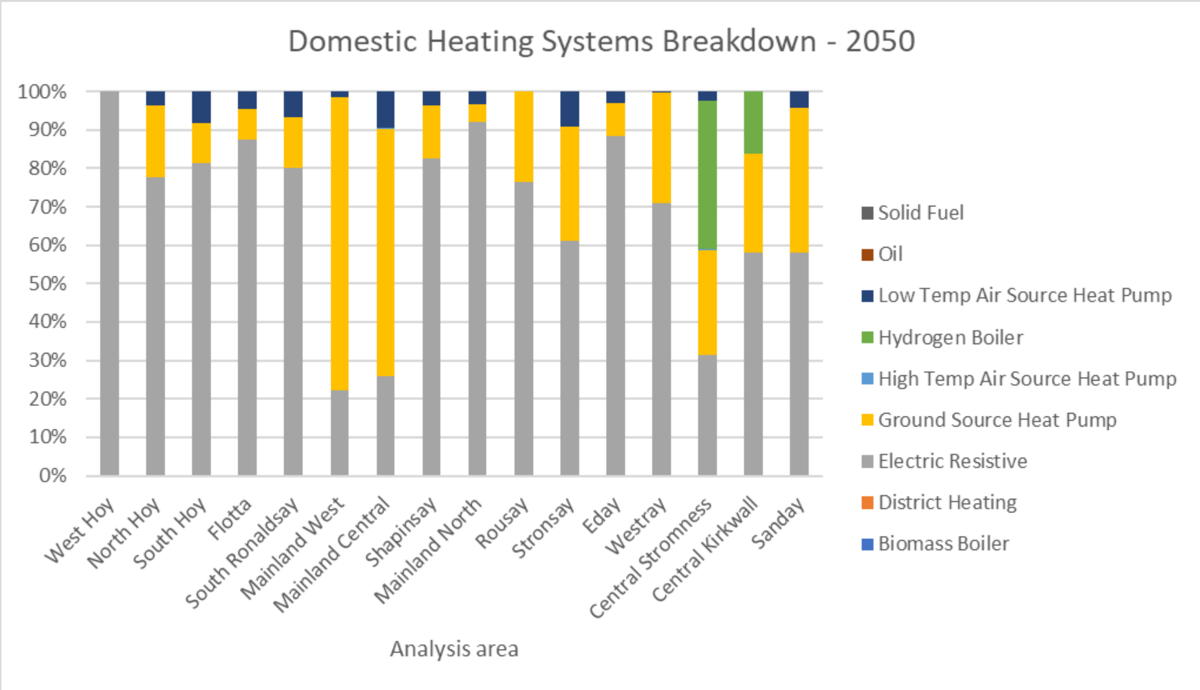

Figure 92 – Domestic heating systems, scenario 8

The uptake of domestic insulation measures in this scenario is very similar to that of Scenario 1b, the most noticeable difference being a smaller number of properties insulated on Westray (Figure 93).

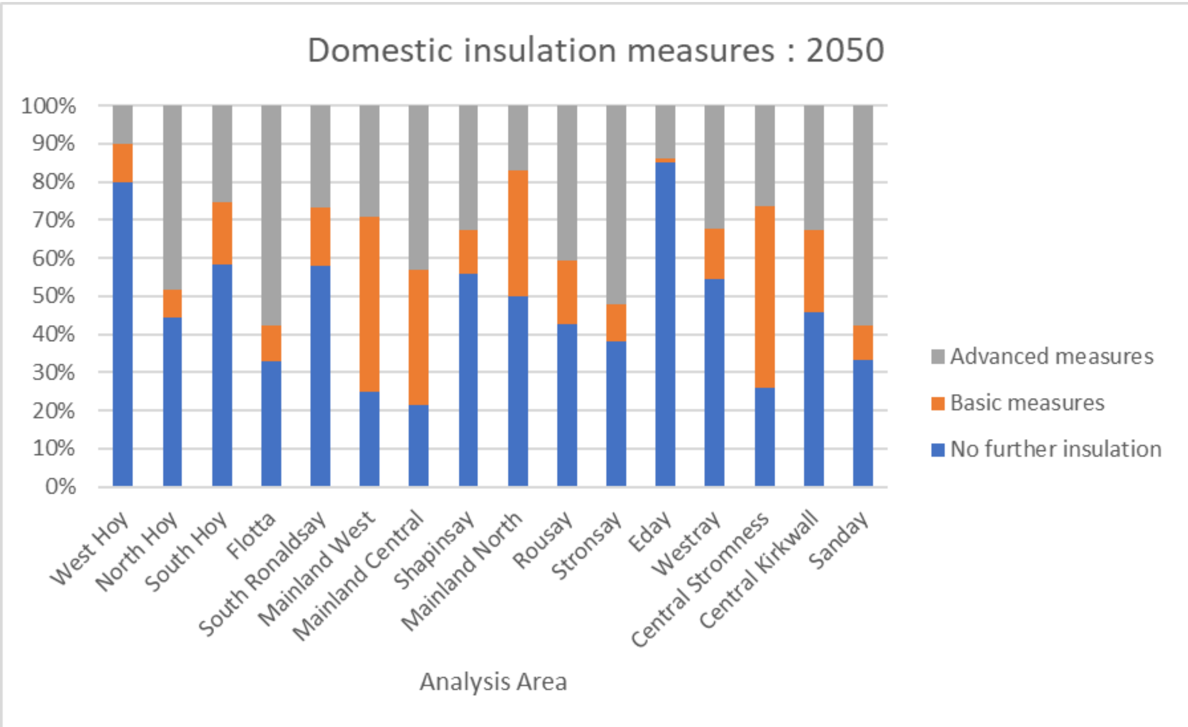

Figure 93 – Domestic insulation, scenario 8

The energy mix for non-domestic heating systems is very similar to that of Scenario 6, although some usage of oil is retained on Shapinsay and Eday (Figure 94).

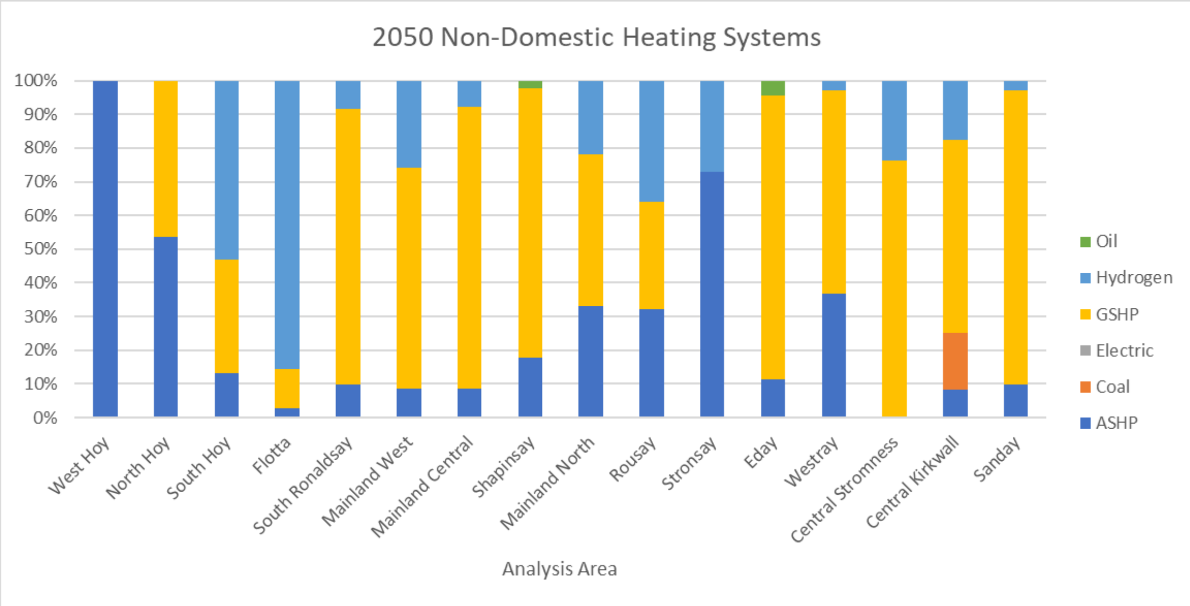

Figure 94 – Non-domestic heating systems, scenario 8

Figure 95 shows the changes in primary energy supply over time. Compared with previous four scenarios, more tidal and wind generation is picked by optimiser to achieve economic optimal solution. The upgraded electricity interconnector allows for increased net electricity exports from the earliest time period onwards. By 2050, emissions are 0.54 ktCO_2 / year which is just below that of scenario 3.

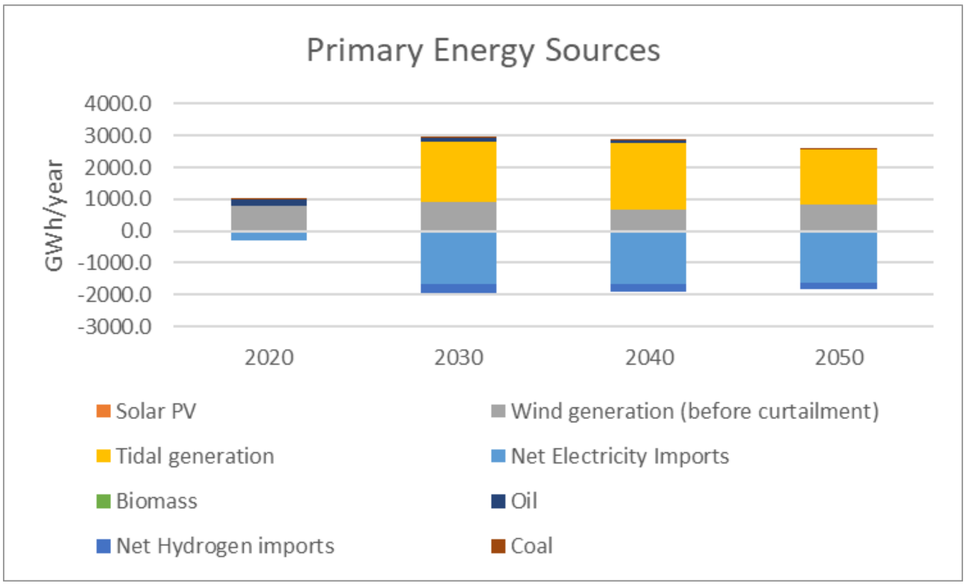

Figure 95 – Primary energy sources, scenario 8

9 Appendix B – The EnergyPath Networks™ Approach

This Appendix B describes the EnergyPath Networks (EPN) modelling approach which has been used for a number of local areas around the UK, and which has been further modified to represent Orkney in this project. This Appendix B is therefore predominantly generic and includes references both to Orkney-specific options and to some options which are applicable in other areas but which may not be applicable in Orkney.

It explains the data and inputs that are created, on a building-by-building level of granularity, along with the process which EnergyPath Networks uses to assess the options through its Decision Module.

9.1 Overview

EnergyPath Networks is a whole system optimisation analysis framework that aims to find cost effective future pathways for local energy systems to reach a carbon target whilst meeting other local constraints. EPN is spatially detailed, covers the whole energy system and all energy vectors, and projects change over periods of time. The focus is decarbonisation of energy used at a local level.

An overview of EPN is shown in Figure 96 overleaf.

At the core of EPN, a Decision Module compares decarbonisation pathways and selects the combination that meets the CO_2 emissions target set for the local area at the lowest possible total cost to society[56].

A variety of local energy system pathways are possible to meet emissions targets. Running multiple EnergyPath Networks scenarios and doing detailed sensitivity analyses reveals decarbonisation themes that are prevalent across all scenarios.

EPN uses optimisation techniques in the Decision Module to compare many combinations of options (tens of thousands) rather than relying on comparisons between a limited set of user-defined scenarios (although scenarios of different inputs are still typically used and the Decision Module then runs within each of these scenarios).

[56] For the total costs considered in the model and as set out in the following sections. Some costs are not considered, for example electricity network reinforcements outside of the study area or the disruption to the local economy during construction.

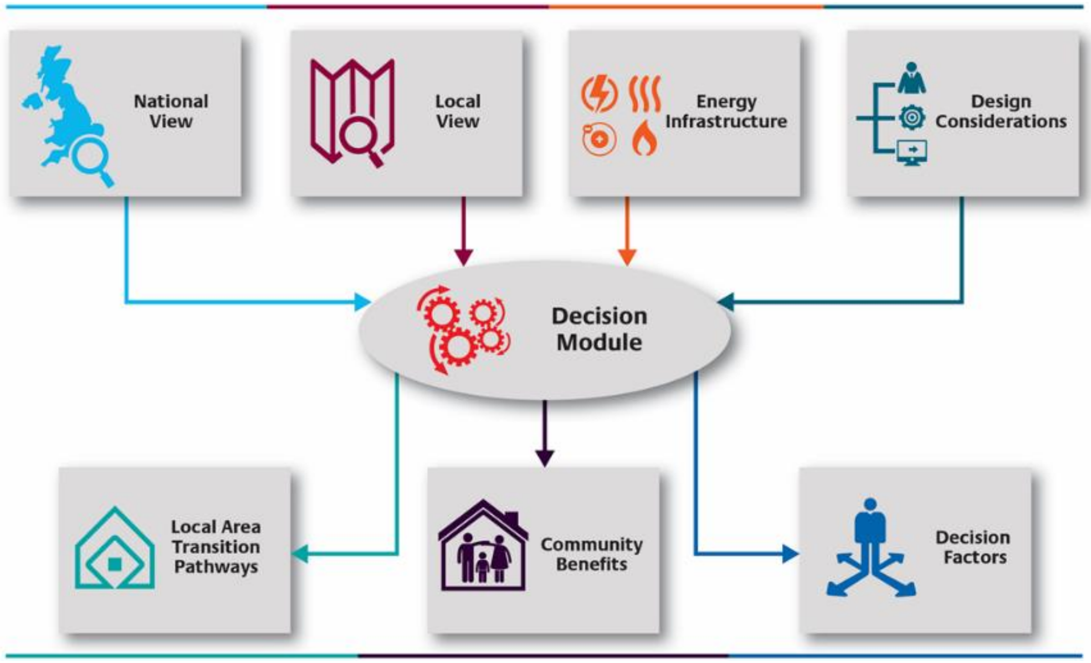

Figure 96 – Overview of EnergyPath Networks

EnergyPath Networks is unique in combining several aspects of energy system planning in a single tool:

- Integration and trade-off between different methods of meeting heat demand – e.g. gas, solid/liquid fuels, electric power, hydrogen, district heating schemes, etc.
- Integration through the energy supply chain from installing, upgrading or decommissioning assets (production, conversion, distribution and storage) to upgrading building fabric and converting building heating systems.
- Inclusion of existing and new build domestic and commercial buildings.
- The spatial relationships between buildings and the networks that serve them, so that costs and benefits are correctly represented for the area being analysed.
- Spatial granularity down to building level when the input data is of appropriate quality.
- A modelled time frame of 2020 to 2050.

Taken together, the analyses enable informed, evidence-based decision-making and can be used to ensure long-term resilience in near-term decisions, mitigating the risks of stranded assets.

9.2 Data Sources

EnergyPath Networks requires data for the local buildings and energy networks within the study area. Primary sources of data used in this study on building types, condition and thermal properties are shown in Table 5. Primary sources of gas and electricity network data, such as network configuration, topography and heat networks, are shown in Table 6.

Table 5 – Primary data sources used in EnergyPath Networks study of Orkney – Buildings

Building Data	
Item	**Primary Data Sets**
Domestic building archetype	Ordnance Survey (OS) Mastermap and AddressBase, Orkney Islands Council Survey data.
Domestic building thermal properties	Buildings Research Establishment: Standard Assessment Procedure calculator
Domestic building current condition	Orkney Islands Council Survey data, Scottish Housing Survey
Domestic appliance use profiles	DECC household electricity survey[57]
Domestic retrofit costs by building type and quantity of insulation	Energy Technologies Institute data[58]
Domestic heating system prices	DECC inputs into domestic RHI and BEIS RHI implementation data
EV charging profiles	National Travel Survey analysis[59]
Non-domestic building use class	Ordnance Survey, Scottish Heatmap
Non-domestic building energy profiles	University College London CARB2 data[60], CIBSE energy benchmarks[61], Scottish Heatmap, BEIS Building Energy Efficiency Survey (BEES)[62], BEIS Cost Optimal Energy Performance of Buildings Directive[63]

[57] https://www.gov.uk/government/publications/household-electricity-survey--2

[58] ETI's Optimising Thermal Efficiency of Existing Housing project .Element Energy report "Review of potential for carbon savings from residential energy efficiency Final report" https://www.theccc.org.uk/wp-content/uploads/2013/12/Review-of-potential-for-carbon-savings-from-residential-energy-efficiency-Final-report-A-160114.pdf

[59] Internal Project. Unpublished

[60] http://www.ucl.ac.uk/energy-models/models/carb2

[61] The Chartered Institution of Building Services Engineers*: Energy benchmarks (TM46: 2008)*

[62] https://www.gov.uk/government/publications/building-energy-efficiency-survey-bees

[63]https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/770783/2nd_UK_Cost_Optimal_Report.pdf

Table 6 – Primary data sources used in EnergyPath Networks study of Orkney – Networks

Network Data	
Item	**Primary Data Sets**
Electricity network: current configuration	Distribution Network Operator (Scottish and Southern Electricity Networks)
Gas network: current configuration	N/A in Orkney
Topography – building locations, building heights and existing road network	Ordnance Survey
Electricity network costs	Distribution Network Operator (Scottish and Southern Electricity Networks), ETI Infrastructure Cost Calculator[64]
Electricity network technical parameters	Distribution Network Operator (Scottish and Southern Electricity Networks
Gas network costs	ETI Infrastructure Cost Calculator
Heat network costs	ETI Infrastructure Cost Calculator, Arup[65]
Heat Network technical parameters	Arup[66]
Energy Centre costs	ETI data (Macro Distributed Energy project)[67]
Energy Centre technical parameters	ETI data (Macro Distributed Energy project) [68]

9.3 Domestic Buildings

The thermal efficiency of domestic buildings is related to the construction methods used, the level of any additional insulation that has been fitted and any modifications that have been undertaken since construction. The oldest buildings in the UK generally have poor thermal performance compared with modern buildings. In addition to building age, the type and size of a building also have a direct influence on thermal performance. For example large, detached buildings have a higher heat loss rate than purpose-built flats, due to their larger external surface area per m^2 of floorspace.

Buildings are categorised into five age bands in EnergyPath Networks, from pre-1914 to the present, shown in Table 7. These are broadly consistent with changes in building construction

[64] http://www.eti.co.uk/programmes/energy-storage-distribution/infrastructure-cost-calculator

[65] Arup. Support for EnergyPath Networks: Task 007: Non-domestic Heat Systems Costs. Unpublished

[66] Arup. Support for EnergyPath Networks: Task 007: Non-domestic Heat Systems Costs. Unpublished

[67] http://www.eti.co.uk/library/macro-distributed-energy-project/

[68] http://www.eti.co.uk/library/macro-distributed-energy-project/

methods (as defined in building regulations) and so represent different levels of 'as built' thermal efficiency. The thermal efficiency of future new homes represents the minimum efficiency level required by current building regulations. There are ten modelled domestic building types, shown in Table 8. This allows approximately 60 different age and building type combinations which are used to define the thermal characteristics of existing and planned domestic buildings.

Table 7 – Domestic building age bands

Property Age Band
Pre – 1914
1914 – 1944
1945 – 1964
1965 – 1979
1980 – Present
New Build

Table 8 – Domestic building types

Property Type
Converted Flat: - Mid Floor / End Terrace
Converted flat: - Mid Floor / Mid Terrace
Converted Flat: - Top Floor / End Terrace
Converted Flat: - Top Floor / Mid Terrace
Detached
End Terrace
Mid Terrace
Purpose-Built Flat: - Mid Floor
Purpose-Built Flat: - Top Floor
Semi-detached

9.4 Current Housing Stock

Once the current characteristics of a building have been defined, based on its age and type, the basic construction method can then be categorised. For example, the oldest buildings in the region can be expected to be constructed with solid walls. Buildings constructed between 1914 and 1979 are more likely to have been built with unfilled cavity walls. Buildings constructed from 1980 onwards are likely to have filled cavity walls. Where data (for example, Energy Performance Certificates) shows that they are likely to be present, thermal efficiency improvements that have been carried out since construction (such as filling cavity walls) are also included.

Where available, address level data is utilised in the EnergyPath Networks modelling to provide accurate building attributes. Missing building attributes, for example types of wall or windows are filled using rules based on Scottish Housing Survey data.

The retrofit measures used in EPN in the study are shown in Table 9. Table 10, Table 11 and Table 12 show the effectiveness of the different types of insulation studied in the model.

Table 9 – Domestic retrofit measures

Domestic Retrofit Measures
Cavity wall insulation
Double glazing
Energy-efficient doors
External wall insulation
Floor insulation
Internal wall insulation
Loft insulation
Mechanical ventilation
More than triple glazing[69]
New build upgrade to High Thermal Efficiency
Reduced infiltration 1 (Draught proofing)
Reduced infiltration 2 (Whole dwelling)
Triple glazing

Table 10 – Loft U-values

Loft Insulation	U-Value (W / m^2 k)
None	2.3
less than 100 mm	0.93
100 up to 199 mm	0.37
200 mm or more	0.17
New build loft insulation	0.13
No loft	0

[69] Consideration of improving the thermal performance of glazing above that of the assumed level of triple glazing, for example improving the U value from 1.8 W/m²K to 1 W/m²K

Table 11 – Window U-values

Window Type	U-Value (W / m² k)
Single glazing	4.81
Double glazing	2.3
Triple glazing	1.8
New build glazing	1.4
More than triple glazing	1

Table 12 – Wall U-values

Example Wall Type	U-Value (W / m² k)
Pre-1914 unfilled cavity wall	2.07
Pre-1964 solid uninsulated wall	1.74
1914-1979 unfilled cavity wall	1.58
1914-1979 filled cavity wall	0.64
1980-present unfilled cavity or uninsulated solid wall	0.6
Pre-1980, solid external/internal insulated wall	0.45
1980-present, solid external/internal insulated wall	0.24

9.5 Current and Future Domestic Heating Systems

The definition of current (primary) heating systems is handled in a similar way to the definition of the building fabric. Information is used to identify the heating system as follows:

1. Xoserve[70] data is first used to identify which buildings in the local area are not connected to the gas grid (in this case the entirety of Orkney).
2. Direct user input is used where the actual heating system in individual buildings is known (e.g. from energy Performance Certificates).
3. Defining logic rules based on the most likely heating system combinations within each archetype group. In Orkney, this is based on the Orkney Islands Council Affordable Warmth Survey.

[70] Xoserve provide services to the gas industry, including management of gas supplier switching and transportation transactional services, www.xoserve.com

Once the current thermal efficiency of a building has been defined, Ordnance Survey MasterMap and LIDAR data is used to establish its floor area and height. With this knowledge of a building's characteristics there is sufficient information to perform a Standard Assessment Procedure (SAP) calculation[71]. SAP calculations are used to calculate the overall heat loss rate and thermal mass of domestic buildings in the study area.

EnergyPath Networks utilises these SAP results, as well as detailed retrofit and heating system cost data, to group buildings into similar archetypes. EnergyPlus[72] is used to calculate dynamic energy profiles for heat and power demand for each group, for the current and all potential future pathways. These pathways include potential to install varying levels of retrofit and different future heating systems in multiple combinations. Restrictions are applied so that inappropriate combinations are not considered, so for example loft insulation cannot be fitted to a mid-floor flat. EnergyPath Networks also filters out heating systems and storage combinations that cannot be sized to a large enough power within a home to meet a predefined target comfort temperature and hot water requirements based on the EnergyPlus analysis.

Possible current and future heating system combinations are shown in Table 13. Three primary elements are defined in each heating system combination:

1. The main heating system.
2. A secondary heating system which can provide additional heat or hot water.
3. Thermal storage – either not present or a hot water tank[73].

[71] The Standard Assessment Procedure (SAP) is the methodology used by the UK Government to assess and compare the energy and environmental performance of dwellings. (https://www.gov.uk/guidance/standard-assessment-procedure)

[72] EnergyPlus is a widely used dynamic building energy modelling tool developed by the US Department of Energy

[73] The heating tank sizes were chosen so that the heating system combinations had sufficient capacity to meet demand in a range of buildings, without being infeasibly large for the available space.

Table 13 – Heating system combinations

Primary Heating System	Secondary Heating System	Heat Storage Technology
Oil / LPG Boiler	None	None
Oil / LPG Boiler	Electric Resistive	None
Biomass Boiler	None	None
High Temperature Air Source Heat Pump	None	1000 litre water tank
Low Temperature Air Source Heat Pump	None	1000 litre water tank
Low Temperature Air Source Heat Pump	Solar Hot Water	1000 litre water tank
Electric Resistive Storage Heating	Electric Resistive	1000 litre water tank
Electric Resistive	Solar Hot Water	None
Ground Source Heat Pump	None	500 litre water tank
Ground Source Heat Pump	None	1000 litre water tank
District Heating	None	None
Low Temperature Air Source Heat Pump with electric resistive top up	None	1000 litre water tank
Low Temperature Air Source Heat Pump with electric resistive top up	Solar Hot Water	1000 litre water tank
Hydrogen Boilers	None	None

For each domestic building the modelling assumes that the heating system will be replaced twice between now and 2050, (referred to as transitions one and two). This assumes that heating systems are replaced at their end of life (generally around 15-20 years). On each of these occasions there is an opportunity to change to an alternative heating system and perform some level of building fabric retrofit. Different heating systems reach end of life at different times, but there would need to be some coordination of the change if transitioning to a district heat or community system. Three different levels of retrofit (thermal performance enhancement) are considered, ranging from do-nothing to a full retrofit[74]. In addition, each heating system option

[74] A basic retrofit package consists of cavity wall and loft insulation only, whereas a full retrofit would also include external wall insulation and improved glazing (up to triple glazing).

(see Table 13) can be combined with advanced heating controls[75] and each level of retrofit. Options will be excluded if a new heating system technology is unable to provide sufficient power to meet heat demand in a building with a given level of retrofit. These combinations mean that for each building there can be as many as 126 different future pathways which must be considered.

9.6 Non-Domestic Buildings

Non-domestic (commercial and industrial) building stock is more diverse than domestic stock. There are a wide variety of construction methods and few robust data sets are available defining the design of any particular building, its heating system or thermal performance. Due to these limitations, an energy benchmarking approach is used to establish the energy demand of the non-domestic stock.

Different building types are given an appropriate energy use profile per unit of floor area. The building type represents how the building is used (e.g. industry, retail, offices, school) and is sourced from a variety of datasets including OS Address Base and Scottish heatmap.

Benchmarks are defined for electricity (direct electric, ground source heat pump and air source heat pump), hydrogen, oil and heat demand in 30-minute time periods for different characteristic heat days. The characteristic heat days for which energy demand profiles are defined are shown in Table 14. Benchmarks are defined for current and future use to represent changing energy use over time.

Table 14 – Characteristic heat days

Characteristic Heat Day
Autumn Weekday
Autumn Weekend
Peak Winter
Spring Weekday
Spring Weekend
Summer Weekday
Summer Weekend
Winter Weekday
Winter Weekend

The footprint floor area and height for each building is derived from the OS MasterMap and LIDAR data. The building height is then used to establish the number of storeys, from which the total building floor area is estimated. Using an energy benchmark (derived from CIBSE and CARB2 data) appropriate to the particular use class, the half hour building energy demand for gas, electricity and heat is calculated for each of the characteristic days.

[75] Which are assumed to provide a small reduction in energy demand through better control. There is an extra cost to installing these controls.

It was challenging to assign use classes to some Orkney non-domestic buildings due to data quality. Where possible, other datasets were used to validate alongside a process of manual checking using satellite and street imagery and a checking process designed to identify buildings with a floor area untypical for the assigned use class.

For both domestic and non-domestic pathway options, EnergyPath Networks includes costs of replacing all technologies at their end of life. At these points technologies can be replaced with a lower carbon system or like-for-like. For example, even in a scenario without a local carbon target, costs will be incurred when boilers and windows are replaced with analogous technologies.

9.7 Energy Network Infrastructure

In order to assess potential options for future changes to energy systems, knowledge of current electricity, gas and heat network routes and capacities is required. From this the costs of increasing network capacities in different parts of the local area, as well as extending existing networks to serve new areas, can be calculated.

The road network is used in EnergyPath Networks as a proxy to calculate energy network lengths. Current and future capacities are established using DNO data (when available) and steady-state load flow modelling of networks. For example, EnergyPath Networks will find the load at which a Low Voltage (LV) feeder will require reinforcement and the costs associated with doing so. The cost of operating and maintaining the networks varies with network capacity and is modelled using a cost-per-unit length, broken down by network asset and capacity.

The EnergyPath Networks method does not replicate the detailed network planning and analyses performed by network operators. Rather, the energy networks are simplified to a level of complexity sufficient for numerical optimisation and decision-making. The method is used to model the impact of proposed changes to building heat and energy demand on the energy networks that serve them, for example increased or reduced capacity. The costs of these impacts can then be estimated and the effects of different options on different networks can be compared.

Only network reinforcements required inside the study area are explicitly considered as options in EPN. Reinforcements outside Orkney are considered in the ESC's Energy System Modelling Environment (ESME) model and so are costed in the future electricity price that is then used in EPN. A significant increase in electricity demand in Orkney is likely to require reinforcements at transmission and distribution levels outside of the modelled area, but these costs are not considered in the model.

SSEN provided the following data for the current electricity network:

1. Locations and nameplate capacities of the HV (33kV to 11kV) and LV (11kV to 400V) substations.
2. HV to LV substation connections.
3. Average costs of replacing network assets.

EnergyPath Networks synthesises the routes of the HV to LV substation connections assuming that feeders follow the shortest route allowed by the road network. Customer connections are then derived based on nearest substation and peak load constraints for each feeder. Non-domestic buildings with high demands are assumed to connect directly to the HV network. Network feeder capacities are then calculated based on the current load on each feeder and a headroom allowance. Voltage drop and thermal limits are considered when establishing asset capacity requirements. EnergyPath Networks performs steady state load flow modelling for electricity and heat networks using the Siemens tool PSS®SINCAL[76].

9.8 Spatial Analysis

Once all the building data has been analysed and the buildings located, it is possible to identify their nearest roads, which shows where the buildings are most likely to be connected to energy networks.

As described in Section 9.7, it is assumed within EnergyPath Networks that energy networks follow the road network. Identification of the road nearest to each building allows the energy demand (for gas, heat and electricity) of that building to be applied to the appropriate energy networks at the appropriate point on those networks.

In this way the total load and the load profile for each energy network can be calculated at different scales from individual building level, through local networks up to aggregate values for the whole study area. This allows an understanding of different energy load scenarios in different parts of the local area and the energy flows between those locations. In addition, an understanding of network lengths and required capacities can be established.

9.9 Analysis Areas

Due to the complexity of the number of different options available in EnergyPath Networks (for buildings, networks and generation technologies) the total problem cannot be solved at individual building or network asset level. The study area (Orkney) is divided into a number of spatial analysis areas. Decisions are made at this level based on aggregating similar buildings and network assets within each area.

The analysis areas are necessary within the EnergyPath Networks model but do not correspond directly to local districts, wards or neighbourhoods.

Within each analysis area, different components of the system are aggregated. Aggregation of buildings is performed based on energy demand and cost of retrofitting insulation and new heating systems. This way, similar buildings within an individual analysis area will all follow the same pathway. Similarly, decisions on network build and reinforcement are made at an aggregated level. If the electricity loads in one analysis area increase, such that the aggregated capacity of the low voltage feeders is exceeded, then reinforcement of all low voltage feeders within that area will be assumed to be required. The same applies for all other aspects of the energy networks such as low voltage substations, high voltage feeders and substations and heat network capacity.

[76] http://w3.siemens.com/smartgrid/global/en/products-systems-solutions/software-solutions/planning-data-management-software/planning-simulation/pss-sincal/pages/pss-sincal.aspx

Since the network options are aggregated, it is important that the boundaries between analysis areas do not cut across the electricity network. It would not be realistic to reinforce the 'downstream' end of an electricity feeder without considering the impact of the loads on those components further upstream in that network.

To ensure consistency in the analysis of electricity network options, the study area was divided by considering each high voltage substation within the local area and all of the electricity network downstream of each substation to give the analysis areas discussed above. Some simplifications to create continuous areas and to remove a low usage private wire substation were applied.

Once the analysis areas had been defined, energy network links between them were defined. This allows transmission of heat, gas and electricity across the analysis area boundaries.

The Analysis Areas are shown in Figure 41 at the start of these appendices.

9.10 Local Energy System Design Considerations

Options which are not considered technically feasible are excluded from EnergyPath Networks – for example, fitting loft insulation into a mid-floor flat or cavity wall insulation to a building which has solid walls.

There are other options which, whilst they may be possible, are not practical in a real-world environment. For example, the use of ground source heat pumps in areas of dense terraced housing: a lack of space means that cheaper ground loop systems cannot be fitted, whilst there is insufficient access for the equipment required to create vertical boreholes. In addition, the heat demand for a row of terraced houses may cause excessive ground cooling in winter leading to inefficient heat pump operation and a need for additional top-up heat from an alternative source.

Consumer preferences also influence suitability of certain options. The installation of domestic hot water tanks for heat storage is a good example. Many low-carbon heat technologies, such as air source heat pumps, work at a lower output power than conventional gas boilers, and this can require the use of heat storage in order to be able to meet peak demand for heat on cold days. However, many households have removed old hot water tanks and fitted combi-boilers to provide hot water on demand. This allowed the space previously occupied by the hot water tank to be repurposed for other uses, which householders find valuable, such as additional household storage.

For example, the English Housing Survey[77] shows that 54% of homes had a combi-boiler in 2016 with this figure rising by around 2% a year since 2001. These consumers often place a high value on the space that has been made available by doing this and are unlikely to embrace heat solutions that require large amounts of domestic space to be sacrificed. A proxy for the value that consumers place on space in their homes is property market values normalised by floor area. With median house price costs in England and Wales in 2017 varying from £32,000 (within

[77] https://www.gov.uk/government/statistics/english-housing-survey-2016-to-2017-headline-report

County Durham) to £2,900,000 (within Westminster)[78] it is clear that the options for using space for domestic heat storage are likely to be heavily dependent on local factors. Consumer behaviour cannot credibly be predicted at this level but factors like this are considered in a Local Area Energy Strategy and any resulting feasibility studies.

Table 13 (above) illustrates the storage tank sizes considered in EnergyPath Networks for each primary and secondary heat combination. Particular primary and secondary combinations may be capable of providing the necessary output if paired with larger storage options, e.g. an ASHP in a pre-1914 large detached building may not be able to meet necessary heat demand with a 500 litre storage tank but combining with a larger storage tank is not considered a credible option.

In some cases, it is appropriate to force or constrain different technology options in EnergyPath Networks for particular building types and geographic areas, to reflect technical, commercial, social and consumer choices. For example, if a Local council is planning a wide scale home improvement programme in a particular part of a local area with the objective of tackling fuel poverty then a retrofit programme should be included in the EnergyPath Networks analysis. Alternatively constraints on building modification can mean technologies are restricted, e.g. in listed buildings or inside conservation areas.

9.11 Limitations and Uncertainties in Modelling Inputs

Any technical modelling exercise requires decisions to be made as to the level of complexity and detail that is appropriate. There are several areas where limitations have been applied to limit the complexity of the EnergyPath Networks analysis to keep the scale of the analysis practical, such as grouping buildings into archetypes.

9.11.1 Fixed Input Parameters

Some parameters are considered as fixed inputs within EnergyPath Networks. That is, they are derived externally and presented as inputs to the tool. Any options to vary these parameters are excluded from the decision module. The following energy demands are modelled as inputs:

1. Domestic lighting and appliance demands are based on data from DECC's (Department of Energy and Climate Change)[79] household electricity survey which gives these demands for different house types.
2. Electric vehicle numbers and charging profiles are based upon assumed take-up rates for electric vehicles and are based on car journeys extracted from the Department for Transport's National Travel Survey. This means that distances travelled (level of charge required) and times of arrival (time of charging) reflect the diversity of real world use. The profiles reflect a vehicle charging immediately after it returns home and so represent a worst case scenario for peak network loads. It is possible that an approach to charging management may partially mitigate this.

[78] https://www.ons.gov.uk/peoplepopulationandcommunity/housing/bulletins/housepricestatisticsforsmallareas/yearendingseptember2017

[79] Now part of BEIS (the department of Business, Energy and Industrial Strategy)

3. Non-domestic building demands for current systems and future transition options are calculated based on building use and a set of energy benchmarks.

9.11.2 Building Modelling

Within the domestic building simulation, a standard target temperature profile is taken from SAP and used for all domestic buildings (see section 9.5). This is intended to reflect typical building use patterns. It is recognised that real-world building use will deviate from this profile, as shown by the Energy Follow-Up Survey (EFUS)[80]. To reflect this, diversity factors are applied within EnergyPath Networks when individual building energy demands are aggregated to calculate total network demands. These diversity factors modify both the magnitudes of the demands and the times at which they occur.

Construction standards are assumed for buildings of different ages. For example, all pre-1914 buildings are assumed to have solid walls. Similarly, for some building ages the thermal conductivity of the walls is assumed to be the same for each level of insulation. For example, all walls in buildings constructed between 1945 and 1964 which now have filled cavities are assumed to have the same thermal performance. Note that these performance assumptions are based on 'traditional' brick construction and assume that insulation is correctly installed and performs to its technical potential. Buildings constructed in other ways may not be correctly represented in terms of their thermal performance.

9.11.3 Network Modelling

The network modelling approach assumes that development of future energy systems should be driven by consumer needs. On this basis, the EnergyPath Networks modelling framework works on a traditional network reinforcement model. If load on a network is calculated to exceed capacity, then the network will be reinforced to meet that load.

There is no capability within the model to consider 'Smart' network control or all aspects of Demand Side Response. For example, if a particular feeder in a street was overloaded, a demand side response could be to raise the price of electricity at peak times to decrease consumer demand on the network. EnergyPath Networks will deploy technologies that minimise electricity use at times of peak costs if it is cost effective to do so, but it is not designed to model the behaviours of the DNO or the consumer in this scenario.

SSEN provided data on HV to LV substation connections for Orkney. The building level electricity connections were synthesised based on the road network. There are no existing heat networks in Orkney.

The load-flow modelling is not intended to replace full dynamic network modelling conducted by network operators. EPN uses a steady-state approach which is appropriate for establishing peak loads and the capacity required to meet them, to understand the influence of different options on network costs.

[80] https://www.gov.uk/government/statistics/energy-follow-up-survey-efus-2011

9.11.4 Technology Cost and Performance

EnergyPath Networks models the future energy system which is considered to have the lowest cost to society whilst meeting defined carbon targets. The selected options are influenced by the costs associated with different technologies. The modelled technology cost should represent the cost in a fully competitive UK market, with significant volumes of the technology being sold. This is currently the case for markets for some technologies such as a gas boiler, but not for others such as heat pumps.

Where the market is not fully developed it is not appropriate to use the current price charged to consumers. Instead, an estimate of the current costs of buying and installing is made using a variety of data sources to ensure that estimated costs are within reasonable bounds.

9.12 Technologies

A variety of technologies have been considered within the EnergyPath Networks analysis. These are described below.

9.12.1 Primary Heating Systems

Different current and future heating system combinations have been considered within the analysis. Table 13 shows details of how the main and secondary heating systems have been considered in combination with building level heat storage. Some of these, such as gas and oil boilers, are significant contributors to a building's carbon footprint. Electrically powered heating systems have the potential for much lower emissions, particularly if the electricity is sourced from low-carbon generation. The heating systems assessed are as follows:

- Gas boilers are the main source of heat for domestic premises in the UK at present but are not present in Orkney.
- Oil / LPG boilers are a popular heat source for those buildings which are not connected to the gas network.
- Biomass boilers can provide a low-carbon heat source by burning fuel derived from sustainably sourced wood products.
- Heat pumps use electrical energy to transfer heat energy from one source to another. They are similar to a domestic refrigerator which transfers heat from a cold space to the surrounding room. This is reversed in a heat pump system so that the internal space is warmed by transferring heat from outside. Heat pumps have an advantage compared to other electrically powered heat sources as they produce more heat energy than the electrical energy required to power them. Different types of heat pump are considered:
    - Low Temperature Air Source Heat Pumps (ASHPs) use the outside air as the source of heat and provide hot water to the heating system at temperatures around 45ºC. This temperature is lower than that normally used for domestic heating with a gas boiler and so may require changes to heating distribution systems, such as the provision of larger radiators to allow the building to be heated effectively. These changes are accounted for in the costs of the technology used in the model.
    - Low Temperature Air Source Heat Pump – Gas Boiler Hybrids use a combination of a low temperature ASHP to provide a large proportion of the heat demand but can top

up this heat using a conventional gas boiler at times when it is not efficient to operate the heat pumps, or the heat pump cannot meet the required demand.

- Low Temperature Air Source Heat Pumps can also have supplementary heat provided by direct electric heating when required.
- High Temperature Air Source Heat Pumps are similar to a low temperature Air Source Heat Pump but provide hot water at a higher temperature (typically 55ºC) which may remove the need for other modifications to the heating system.
- Ground Source Heat Pumps use heat energy stored in the ground to provide hot water to the heating system. Since ground temperatures are higher than air temperatures in winter they can operate more efficiently and provide higher water temperatures than air source heat pumps. Space is required, however, to install pipework to extract heat from the ground and this adds considerably to the cost of installing these systems.

- Electric Resistive storage heating is the most commonly used system for buildings which have electric heating. Room heaters are typically charged overnight (where there can be an option to charge the system at a lower, night rate electricity tariff) and then release this heat over the course of the following day.
- Electric Resistive heating without storage provides instant heat through panel, fan or bar heaters.
- District heating provides heat to buildings through pipes that carry the heat from a central heat source. In current systems, this is typically a large gas boiler or gas fired Combined Heat and Power (CHP) plant which provides heat to the network and generates electricity which is either consumed locally or exported to the electricity network. Once installed these systems can be converted from using gas to lower carbon alternatives such as a large-scale Ground Source Heat Pump or a biomass boiler. Equally, if there is no gas supply in the first place, then systems can be designed from the outset with such alternatives.

9.12.2 Building Retrofit Options

Domestic buildings in the UK have been constructed to a wide variety of building regulations depending on their age. Many older buildings have low levels of insulation and require much more energy to keep them warm in winter than those built to more recent regulations.

There are many options available to reduce heat loss from older buildings some of which could also be applied to more modern buildings. Loft insulation, wall insulation (cavity or solid depending on existing building fabric) and triple glazing retrofit options are modelled within the EnergyPath Networks model.

In addition, some minor improvements are considered as secondary measures. That is, “quick wins”, such as draught proofing, that could be installed at the same time as more substantial building fabric upgrades.

9.12.3 Solar

EnergyPath Networks considers the deployment of solar panels within a local area to generate electricity and hot water. Both systems can produce significant amounts of energy in summer months but may produce close to zero energy on winter days when the sun is low in the sky and days are much shorter. This may coincide with times of greatest heat demand, so alternative energy supply options need to be available at these times. Battery options can also be considered in EPN, which are able to store electricity at times of excess supply and discharge at times of high demand.

In the case of electricity generation (solar photovoltaics) the power might be used by the home owner or might be exported to the electricity network if the amount being generated exceeds the demand of the generating building.

Solar hot water systems typically heat water in a hot water tank by circulating a fluid between a heating coil within the tank and the roof mounted panel heated by the sun.

9.12.4 Energy Centre Technologies

A central heat source or Energy Centre is connected to a District Heat Network, providing heat to buildings through pipes. A wide variety of technologies are available that can provide this heat:

- Any available excess heat identified in the local area and input into the model, for example heat from power station or industrial processes can be used directly to provide energy to heat networks.
- Heat pumps can be used at a large scale in a similar way to that discussed above for individual building heating systems. They can use a variety of heat sources:
  - Ground Source Heat Pumps typically use deep boreholes to take advantage of the higher temperatures underground.
  - Water Source Heat Pumps take advantage of the fact that most rivers and seas have reasonably stable temperatures throughout the year. This makes them a good source of heat in the winter.
  - Waste Heat Pumps typically use warm air that is emitted from industrial or commercial purposes. Examples have included warm air vents from the London Underground and heat emitted from the computers within data centres.
- Biomass can provide a low carbon source of heat in two main ways:
  - Boilers burn the biomass to provide heat directly to a network.
  - Combined Heat and Power (CHP) systems work like small-scale power stations where the heat that would normally be discarded to the atmosphere is used to provide heat to a network and the electricity generated is either consumed locally or exported for use in the local electricity network.
- Domestic and industrial waste can be incinerated to provide heat for networks. This can be done in conjunction with a generation system that produces electricity as well as heat.
- In most areas gas can be burnt in three different technologies to provide heat for networks. In Orkney, where there is no gas network, hydrogen can be used in similar manner:
  - Gas/Hydrogen Boilers are large-scale versions of domestic systems.
  - Gas/Hydrogen Engine CHP runs a large engine, similar to that in a heavy goods vehicle. This drives a generator to produce electricity and the heat that would be wasted in the truck radiator and exhaust gas is captured and delivered to the heat network.

- In Gas/Hydrogen Turbine CHP, an engine similar to that on a jet airliner is used to power a generator to produce electricity. The exhaust heat is captured and delivered to the heat network. These types of systems are only likely to be used where there is considerable demand for both heat and electricity.

The technologies selected by EPN in energy centres are often a combination of the above, for example air source heat pumps providing low carbon heat for the majority of the year but gas technologies available to help meet seasonal peak demands. Multiple technologies can also be used together to avoid a single point of failure, for example where EPN models a single large air source heat pump it may be better to deploy several smaller ones to provide greater resilience.

9.12.5 Heat Storage

Heat storage can be considered at two scales:

- Individual domestic storage in hot water tanks.
- Large-scale storage in association with heat networks.

In both cases, it is assumed that more heat could be produced at certain times than is required to meet demand. This provides an option to store that heat and then release it back into the heating system at times when the peak demand is high. It can sometimes be a cost-effective solution as it allows a less powerful heat source to be installed that can be topped up using stored heat at times of peak demand.

Depending on the location in the UK, the value of the floor space lost could outweigh the capital savings associated with installing a heating system with a hot water tank over a more powerful heating system without a hot water tank.

9.13 Carbon Emissions

EPN optimises to calculate the lowest cost route to meeting a defined carbon target. Domestic, industrial and commercial emissions (i.e. those related to buildings) are in scope for the model. Transport emissions and those resulting from land use change are excluded from the analysis.

Some types of non-domestic buildings are projected to have reductions in demand and so emissions over the time period to 2050, even if their heat demand continues to be met using gas or electricity. Emission reductions from these buildings can occur due to:

- Conversion of the national grid to low-carbon electricity which decarbonises the emissions associated with local electricity consumption (as shown Figure 97 below).
- Reduced gas use in buildings where there is historical evidence to support this trajectory – mainly associated with professionally managed buildings whose managers have a commercial incentive to improve energy efficiency.

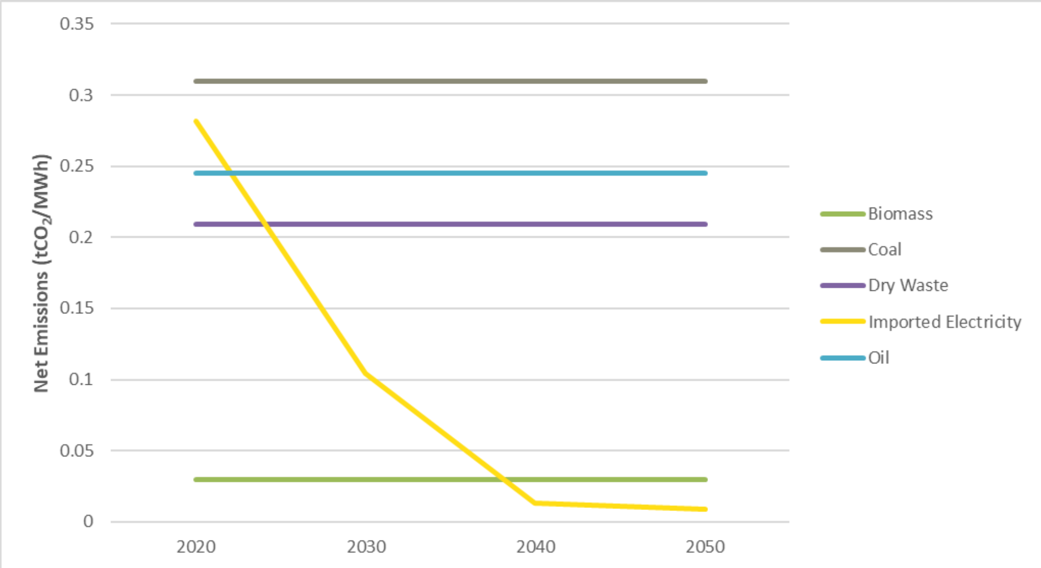

Figure 97 – CO_2 Emissions inputs to EnergyPath Networks

9.14 Cost Optimisation in the Decision Module

EnergyPath Networks has been used to provide evidence to support local area energy planning and the development of local energy system designs able to meet local carbon reduction targets. The importance of other factors such as fuel poverty and health benefits should be recognised in the planning of the future energy system but they are not core parameters in EnergyPath Networks.

Once a set of potential options for the buildings and energy networks in the local area have been identified, the Decision Module compares all valid option combinations and selects the set that meets the local CO_2 emissions target at minimum cost.

The costs considered are the total cost to society for the whole energy system including capital costs, fuel costs and operation and maintenance costs to 2050.

The future costs are discounted. Discounting is a financial process which aims to determine the "present value of future cash flows", or in other words: calculating what monies spent or earned in the future would be worth today. Discounting reflects the "time value of money" – one pound is worth more today than a pound in, say, one year's time as money is subject to inflation and has the ability to earn interest. A discount rate of 3.5% is used, as suggested in the UK Treasury's "Green Book"[81] (used in the financial evaluation of UK Government projects).

Taxes and subsidies are excluded as these are transfer payments with zero net cost to society. Their inclusion in the analysis might result in the selection of sub-optimal solutions. The intention is that, once evidence has been used to define a local area energy strategy and possible future local energy system designs, the deployment and innovation projects needed to implement them can be developed.

[81] Appendix 6: HM Treasury (2018) The Green Book: Central Government Guidance on Appraisal and Evaluation https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/685903/The_Green_Book.pdf

10 Appendix C – Cost Estimates and Assumptions

Appendix B – The EnergyPath NetworksTM Approach, lists the data sources for the costs used for most elements of the model: retrofitting domestic building, industrial and commercial buildings based on the pathway's options, energy centre technologies (heat pumps, boilers and so on), and network costs within the analysis areas. The costs of several technologies closely relating to the ITEG project were reviewed or had not been needed before. The assumptions for these are given in this Appendix C.

10.1 Tidal Generation Costs

Tidal turbines' capital costs for building and installation are taken from the ESC's Energy System Modelling Environment (ESME 4.4) model and shown in Table 15. These closely match values shared by *Orbital Marine Power* for an N'th of a kind installation. For a 2MW tidal turbine unit, the costs are shown in Table 15 assuming 20-year economic and technical lifetime. The price per MW multiplied by the nameplate capacity is used for big units when rolling out tidal generation.

Table 15 – 2MW tidal turbine capital costs

Build Year	2020	2030	2040	2050
Capital Costs (£)	3,381,000	2,961,000	2,541,000	2,205,000
Unit Price (M£/MW)	1.69	1.48	1.27	1.10

10.2 PEM Electrolysis

Polymer electrolyte membrane (PEM) units are modelled to generate 'Green' hydrogen in EPN. The capital cost is assumed as 750 £/kWe in 2020 reducing to 340 £/kWe in 2050 matching the BEIS base case [82]. The cost of the 0.5MW unit on Eday is shown in Table 16 Annual fixed maintenance cost is assumed to be 2.8% of CAPEX and variable operating and maintenance costs (excluding energy costs) is assumed to be 7.7 £/kWh including water consumption and purification facilities for both water and hydrogen product.

Table 16 – 0.5MW PEM electrolysis costs used in EPN

Build Year	2020	2030	2040	2050
Capital Costs (£)	375,000	200,000	175,000	170,000

[82] https://www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base P19

10.3 Wind Generation

Wind turbine/technologies are modelled in Orkney systems by imposing pre-existing wind farms and offering new build options. The capital costs are from the ESC's Energy System Modelling Environment (ESME 3.4) model asset. 20MW wind turbine capital costs are shown in the table below.

Table 17 – 20MW wind turbine capital costs used in EPN

Build Year	2020	2030	2040	2050
Capital Costs (£)	27,600,000	24,400,000	21,300,000	18,800,000

10.4 Fuel Cell CHP

Fuel cell Combined Heat and Power (CHP) plants are modelled and deployed across the Orkney archipelago. A BEIS report[83] suggests that a 50kWe fuel cell should cost £12,173/kWe for a one off and £3,833/kWe at 500 units installed. In addition, £50/kWe/year is suggested as annual fixed running cost. This gives £287,465 for a 75kWe fuel cell with £3,750 annual fixed cost and that is what has been used in the model. Heat and electricity efficiencies are assumed as 27% and 42% respectively.

10.5 Inter-Island Ferry Links

A number of ferry routes between islands are assumed to be already capable of carrying hydrogen at a rate of 0.41MW, so capable of shipping at total of 9.8MWh of hydrogen per day. Additional inter-island ferry links with a much larger capacity of 8.4MW are offered for the model to choose to deploy on these routes: Orkney Mainland Central-Hoy, Mainland Central-Shapinsay, Mainland Central-Westray, Mainland Central-Eday, Eday-Sanday, Eday-Stronsay and Mainland North-Rousay.

EMEC provided an estimate of an achievable cost of hydrogen transport by ferry of £1.84/kg, which we assumed to be split equally between recovery of capital cost and ongoing operating and maintenance costs. This estimate was used to derive a capital cost for using the following assumptions:

- 2 voyages per day
- 20-year economic lifetime
- 4% annual discount rate
- A ferry is assumed to be able to take 12 lorries with the tube trailer's capacity assumed as 250kg.

This resulted in a capital cost estimate of £27.4m for each ferry link, which is £3.3m/MW of hydrogen flow capacity. This compares reasonably well with separate estimates of ferry costs

[83] https://www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base P94

available online. These costs include ferry fare to transport trailers and road haulage to tow the tube trailers.

10.6 Inter-Island Cable Representation

The inter-island electricity cables upgrade options are each modeled as only a single under-sea link between pairs of analysis areas. For example, there are two cables linking Hoy and the UK mainland[84], which are represented as a single link in the model with summation of both capacities and costs imposed for it. All upgrade optional links are listed in Table 18. Capital costs of links within Orkney are estimated based on the ETI's Infrastructure Cost Calculator based on voltages, materials, cross section areas, cable lengths and capacities.

SSE estimate the cost of a scheme upgrading the link between Orkney and the UK mainland with a new 220MW line as £260m[85]. This upgrade is implemented in Scenario 8.

Table 18 – Electricity Cable Cost Estimates

Link Location	Voltage Level Modelled (kV)	Material	Cross Sectional Area (mm^2)	Length (m)	Capacity(kW)	Cost Estimate (£)
Sanday - Stronsay	33	Cu	95	6,173	9,504	1,417,000
Stronsay - Shapinsay	33	Cu	70	12,310	8,019	2,825,000
Shapinsay - Kirkwall	33	Cu	70	2,874	8,019	660,000
Mainland - Rousay	33	Cu	185	2,113	13,662	485,000
Rousay - Westray	33	Cu	70	10,030	8,019	2,302,000
Eday - Sanday	33	Cu	70	4,053	8,019	930,000
Mainland - Hoy	33	Cu	95+240+300	4,400+4555 +4,735	43,065	3,142,000
Hoy - Flotta	33	Cu	95	1,876	9,504	431,000

[84] https://www.ssen-transmission.co.uk/projects/orkney/

[85] https://www.ofgem.gov.uk/publications/ofgem-gives-go-ahead-orkney-transmission-link-subject-conditions

10.7 Inter-Island Hydrogen Pipeline Representation

Potential risks of hydrogen infrastructure deployment are controversial and require considerable research on its reliability and safe operation. However, the main components, like pipelines, storage, and compressors, are technically proven with consideration of hydrogen as fuel. Some authors (see literature referenced in this section) adopt a 10% cost increase for hydrogen pipelines over the estimate of the equivalent system for gas. We have followed their example.

For Orkney archipelago, building undersea pipelines is considered as an option to transport hydrogen between analysis areas in addition to use of tube trailers on ferries. In the EPN model, we impose the techno-economic parameters for these links, including the lifetime, transport distance, operational pressure, pipe sizes, materials and so on. Most national gas transmission distances are within 150-200km[86], while the scale of the hydrogen network across Orkney Island is only around 4-20 km, more like distribution-level gas networks. The gas transport pressure tiers are defined as categories listed in Table 19

Table 19 – Pressure Tiers used by Gas Distribution Network Operator[87]

Tier	Low Pressure (LP)	Medium Pressure (MP)	Intermediate Pressure (IP)	High Pressure (HP)
Pressure Range [bar]	<0.075	0.075 - 2	2 – 7	7 - 70

The deployment investment is estimated based on existing gas systems with a proportional increase for hydrogen; hydrogen pipeline costs based on some gas projects are shown inTable 20. In our study, 10 bar in High Pressure (HP) is assumed as the operational pressure for transmission of hydrogen between islands. The hydrogen pipeline diameter is assumed as 10-inch for Orkney system after considering the hydrogen properties[88] and the peak capacity from model test results[89]. Unit capital cost is assumed as £0.5m/km using IEK-STE's formula for distribution pipeline capital costs, and annual fixed costs use 4% of capital costs for each link, also from the literature.

http://www.natgas.info/gas-information/what-is-natural-gas/gas-pipelines

[87] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/566152/climate-adrep-national-grid-gas.pdf

[88] Hydrogen energy density uses 120MJ/kg energy density. 4°C undersea temperature and 10 bar pressure gives the density 0.88 kg/m3. Fluid velocity is assumed as 10m/s.

[89] 60MW peak hydrogen transport link capacity is found from test results based on current total potential hydrogen demands and network systems within Orkney.

Table 20 – Hydrogen Pipeline Capital Costs Survey

Diameter [Inch]	Capital Cost [£m/km]	Distance Range	Reference
20-30	0.54 – 1.44	Transmission	the US Department of Energy[90] (H2A)[91]
15-40	1.5	Transmission	US Gulf of Mexico[92]
25.6	1.1	Distribution	Element Energy Ltd[93]
10	0.36	Long-distance	Element Energy Ltd
10	0.50	Distribution	IEK-STE[94]

10.8 Hydrogen Market Price

We assume there are no emissions of greenhouse gases associated with imported hydrogen. Flotta, Central Stromness and Central Kirkwall are considered as possible locations at which to site a hydrogen shipping facility although large scale import and export is assumed to be through Flotta.

The market price of hydrogen over the period of the study, out to 2050, is hugely uncertain. Estimates were obtained from the available literature to ensure we modelled a realistic range.

McKinsey reporting for Hydrogen Council predicts the production costs in a range of $1.4-$2.3/kg[95], which is £30-50MWh with 33.6kwh/kg hydrogen energy density and 0.73 GBP to USD exchange rate; the international distribution costs are estimated as $2-$3/kg, which is £43-£65/MWh in hydrogen energy price. Levelized cost of hydrogen production from dedicated offshore renewable sources has been estimated to fall to around £75/MWh [96]. The cost import

[90] F. H. Saadi et al., Relative costs of transporting electrical and chemical energy. Energy & Environmental Science, 2018, 11, 469

[91] H2A: Hydrogen Analysis Production Models are tools developed by H2A team at the US National Renewable Energy Laboratory (NREL).

[92] M. J. Kaiser, Offshore pipeline construction costs in the US Gulf of Mexico

[93]https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf

[94] GIS-based scenario calculations for a nationwide German hydrogen pipeline infrastructure. International Journal of Hydrogen energy, 38, 2013, 3813-3829

[95] https://hydrogencouncil.com/wp-content/uploads/2021/02/Hydrogen-Insights-2021-Report.pdf

[96]https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011499/Hydrogen_Analytical_Annex.pdf

could be £23/MWh in a lower case[97]. In our study, the range for hydrogen market price contains the international distribution and production costs as shown in Table 21. The total hydrogen market prices use insensitivity tests were from £50/MWh to £150/MWh to cover the possible price range.

Table 21 – Hydrogen market price estimate

	Low Price [£/MWh]	High Price [£/MWh]
Production cost	30	75
Transport	23	65
Total, combining extremes	53	140
EPN test range	50	150

[97] https://www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base