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Assessment of options for a smart, resilient and low-carbon multi-vector energy system in the Scottish Borders

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Contents

Executive summary

Smart local energy system (SLES) can provide value from local renewable generation and demand-side flexibility to help achieve the UK net-zero target. In this report, we provide a high-level feasibility evaluation for three categories of options for decarbonisation, focusing on the Scottish Borders, a region that has significant renewable energy potential and an urgent need for decarbonised heating and transportation if it is to achieve the UK and Scottish Government's net-zero target, and improve the welfare of residents. The decarbonisation of heating is particularly important in the Scottish Borders, as there are many off-gas-network households in the rural areas that heat their home with carbon-intensive fuels, like heating oil, coal, and Liquefied Petroleum Gas (LPG). In addition, these carbon-intensive fuels are more expensive than natural gas, causing a comparably large proportion of households to fall into fuel poverty.

These options include:

1. Electrification of heating and transportation with SLES options, including local flexibility markets, to alleviate the need for network upgrades and improve renewable hosting capacity
2. Seasonal thermal energy storage options to use the curtailed wind for district heating
3. Hydrogen options for vehicle refuelling and natural gas replacement.

The evaluation aligns with four targets: reaching net-zero; economic benefits for residents, the energy system and the council; renewable hosting capacity and the feasibility and credibility of the options. Within the EnergyRev research consortium, our team focuses on unlocking the benefits of SLES by studying new market designs and proposing innovative business models that can be scaled out across the UK and internationally.

Our key findings for each of the three categories of options are:

A. Electrification and smart local energy systems

SPEN Distribution Future Energy Scenarios (SPEN) provides forecasts of the possible number of heat pumps (HPs) and electric vehicles (EVs) that will be connected to local primary substations under several future scenarios (e.g., high uptake scenario, low uptake scenario) to achieve the net-zero target (SP Energy Networks, 2021). We conducted the study for the different HP and EV roll-out scenarios and we find that the electrification of heating and transportation can be beneficial in reducing carbon emissions and the fuel poverty rate. Under current electricity carbon intensity, the complete electrification of heating by heat pumps and transportation by electric vehicles can reduce more than 70% of carbon emissions of residential heating and transportation respectively in the Scottish Borders. The reduction can increase to more than 90% when there are more renewable installations. Replacing non-gas heating with heat pumps can decrease the fuel poverty rate in Newcastleton from 49.87% to 35.32%, and reduce the fuel poverty rate in the Scottish Borders from 29.3% to 21.8%.

However, these heat pumps could trigger expensive network upgrade costs. For Newcastleton primary substation only, the network upgrade costs for hosting the heating demand could be up to £24.29K. For the overall Scottish Borders, the upgrade costs for the primary substations could be up to £30.26M for the electrified heating demand and £10.24M for the electrified transportation demand in 2030. However, this can be avoided with a local flexibility market designed to smartly shift the demand of electrified heating and transportation. It would mean there was no need for network upgrades in the Newcastleton primary substation in 2030. For the overall Scottish Borders, a local flexibility market can also reduce the network upgrades for hosting electrified heating by £4.14M out of the original £30.26M in 2030. The upgrade cost reduction can be up to 95% for electric vehicles.

A local flexibility market can also lead to improved renewable hosting capacity, saving the upgrade costs for installing more renewables. The local flexibility market based on heat pumps can improve the hosting capacity of the local primary substations for wind generation by 3.6% and 4.8% for the two 2030 scenarios in the Scottish Borders. It can also improve the hosting capacity for solar generation by 4.8% and 7.6% for the two 2030 scenarios. Coordinating the electric vehicles by the local flexibility market leads to higher benefits. It can improve the hosting capacity of the primary substations for wind generation by 13.1% and 22.6% (corresponding to 37.03 and 72.46 MW) for the two 2030 scenarios in the Scottish Borders. As for solar generation, the improvement could be 11.1% and 22.1% (corresponding to 36.34 and 84.1 MW) for the two 2030 scenarios.

Recommendations

Based on our feasibility analysis for these options, several recommendations are made.

- Roll out heat pumps, especially in areas with a high non-gas rate. The fuel poverty rate and carbon emissions could be significantly reduced by heating electrification.
- Natural gas heating needs to be replaced to reach net-zero. Replacing the existing gas with other clean energy like hydrogen could be more economic than heat pumps.
- Organise a local flexibility market for heat pumps for areas with a high non-gas rate and weak network infrastructure as it will reduce the network upgrade costs.
- Organise a local flexibility market for electric vehicles because it can lead to significant reduction in upgrade cost and increase in renewable hosting capacity.

B. Seasonal Thermal Energy Storage

Seasonal thermal energy storage using curtailed wind and varying wholesale electricity prices is analysed based on a modelled residential district heating scheme at Galashiels.

For electricity prices and wind curtailment events in 2019, the replacement of direct electric heaters with heat pumps and short-term thermal energy storage reduces total system costs (combined capital costs and operating costs) by 49%, while adding seasonal thermal energy storage further reduces total system costs by 1%. Therefore, there is little value in seasonal thermal energy storage using curtailment and electricity prices in 2019.

In the near future (2030) and beyond (2040, 2050) wind curtailment events will be more common, and seasonal thermal energy storage provides far higher value, with this analysis showing negative total system costs. However, these will be mitigated to a degree by higher non-curtailment event prices which are not included in this analysis. More detailed modelling is required to include more realistic total system costs for the future years. Finally, network limitations will have impacts on the ability of these systems to respond to curtailment events.

Recommendations

Seasonal thermal energy storage should be considered in more detail, alongside heat pumps and direct electric heating, to take advantage of wind curtailment events which will increase in the future. This is contingent on access to a market mechanism to enable a discount for responding to wind curtailment events, e.g., the balancing mechanism.

C. Hydrogen

We examined the opportunity to replace Scottish Borders Council's (SBC) current diesel powered vehicles with hydrogen fuel cell equivalents, and also briefly considered options for replacing natural gas in the public supply network.

The current diesel vehicle fleet is responsible for around 5,000 tonnes per year of carbon dioxide emissions. These would be eliminated if all diesel vehicles were replaced with hydrogen (or indeed other zero emissions technology).

To achieve this, a renewable ('green') hydrogen fuelling facility, or Hydrogen Hub, supplying around 1,500 kg hydrogen per day would be enough to supply fuel demand. This would require an average power supply of around 3MW and a water supply of around 14 m3/day. The capital investment, excluding the power supply and land, would be in the region of £2.9M.

The most cost-effective source of power supply would be a wholly-owned, or directly connected and contracted, wind turbine/s. Assuming that this is the case, the cost of the hydrogen produced should be in the region of £3.24 / kg, which would lead to, for example, running costs of a family sized car of around 2.6p/km. This compares very favourably with diesel at around 10.1p/km (at 55mpg and £1.95/litre), or grid electricity supplied through a public charger at around 8p/km. This also assumes that hydrogen produced by the council for its own use would not be subject to tax.

An optimum location for the hydrogen hub has yet to be determined. However, a council-owned site at Lauder has been put forward as a possibility. It is centrally located and well served with roads, gas network connection and is not far from existing wind farms. This is, however, some 20 km from the council offices at Newton St Boswells, which might lead to a cumulative significant additional travel cost and fuel requirement. This needs to be considered in more detail.

For the council's recent fuel consumption level of diesel at 1.9 million litres/year, the cost at current diesel prices of £1.95 per litre would be around £3.7 million per year (although SBC may be able to purchase bulk fuel more cheaply). Using hydrogen produced in the way described, the discounted annual equivalent cost of the 395,000 kg hydrogen required would be around £719,000 – a substantial saving of around £3,000,000 per year which would very quickly offset the initial capital costs.

Given this differential, it may also be possible to create an income stream for the council, while also encouraging the take up of hydrogen vehicles, by selling excess hydrogen to the public. However, this may create a tax situation which would need to be investigated.

Depending on the operational strategy of the council vehicles - whether or not they all return to the same base at the end of each day – it may be necessary to have one or two outlying refuelling points. These could either produce their own hydrogen in-situ, or could be supplied by tanker or pipeline from the hydrogen hub.

Vehicle cost appears at the moment to be around 54% more than a comparable diesel fuelled vehicle; however, this is a very approximate figure due to the lack of publicly available information. We would also anticipate this excess cost decreasing as the technology matures and becomes more widespread.

Hydrogen could also be used for natural gas replacement since boilers can currently use 20% hydrogen. Approximately 1170 GWh/yr, or 80,000 tonnes/year, of natural gas are used in the SBC region. To produce enough hydrogen to displace 20% by volume of natural gas used in the area (6% by energy and emissions) would require a further 5,300kg hydrogen production, at a capital cost of approximately £7.9M, an average power demand of 10MW and a water supply of 48 m3/day. This would have an annualised production cost of around 4.8p/kWh, and would displace about 13,000 tonnes of carbon dioxide per year. Further investigation in co-operation with SGN is recommended.

Recommendations

- Detailed planning of a Hydrogen Hub with a capacity of 1,520 kg/day should be progressed. This should be enough to supply the SBC vehicle fleet, with pre-planned options to expand it to serve non-council demand as it develops. As the council fleet replacement is likely to take several years, there would be scope for such demand to develop within the initial capacity.

  * For context, this would be equivalent to a single medium-small sized fuelling station in Scotland supplying petrol & diesel.

- The Hydrogen Hub location should be identified as part of that detailed planning; an existing council depot at Lauder could be a viable solution with some advantages in terms of its location.

- Power the Hydrogen Hub using a dedicated and directly connected renewable electricity source. This will reduce costs substantially compared to grid sourced electricity, and will eliminate emissions associated with legacy hydrocarbon fuelled power stations still connected to the national grid. Curtailed generation might also make a useful contribution.

- Replace the existing council diesel powered vehicle fleet with hydrogen fuel cell powered vehicles, on the currently proposed timescale for fleet replacement.

- For natural gas replacement, discussions should be held with SGN with a view to either (1) creating additional hydrogen to supply into the network up to 5,280 kg/day average, or (2) accepting surplus hydrogen from the vehicle fuelling facilities. This last option might be valuable in the early stages, especially before demand has fully developed.

I. Introduction

A. Background

The Scottish Borders Council (SBC) is developing its response to the UK government to reach the net-zero target through a Scottish Borders Climate Change Route Map (Scottish Borders Council, 2021) and Borderlands Strategic Low Carbon Energy Masterplan (Borderlands Inclusive Growth Deal). The Route Map and Master Plan aim to provide strategic direction, a framework to guide investment decisions, and a platform for engagement, to underpin economic prosperity driven by an energy transition and becoming an early net-zero carbon region in the UK (before 2045).

Installing more renewables and decarbonising heating and transportation are important to achieve the net-zero target. The Scottish Borders has a large renewable potential, especially wind generation, creating opportunities to support the energy transition. For example, the current operational onshore wind generation in the SBC area is up to 1356.1 MW (The Scottish Borders Council, 2021). The decarbonisation of heating is particularly important in the Scottish Borders, as there are many off-gas-network households in the rural areas that heat their home with carbon-intensive fuels, like heating oil, coal, and Liquefied Petroleum Gas (LPG). In addition, these carbon-intensive fuels are more expensive than natural gas, causing a comparably large proportion of households to fall into fuel poverty.

In this report, we provide a high-level feasibility evaluation of three categories of options for decarbonisation. They include:

1. Electrification of heating and transportation with Smart Local Energy System (SLES) options, including local flexibility market, to alleviate the need for network upgrades and improve the renewable hosting capacity (which is shortened as SLES options in the later content)

2. Seasonal Thermal Energy Storage (STES) options to use the curtailed wind for district heating

3. Hydrogen options for vehicle refuelling and natural gas replacement.

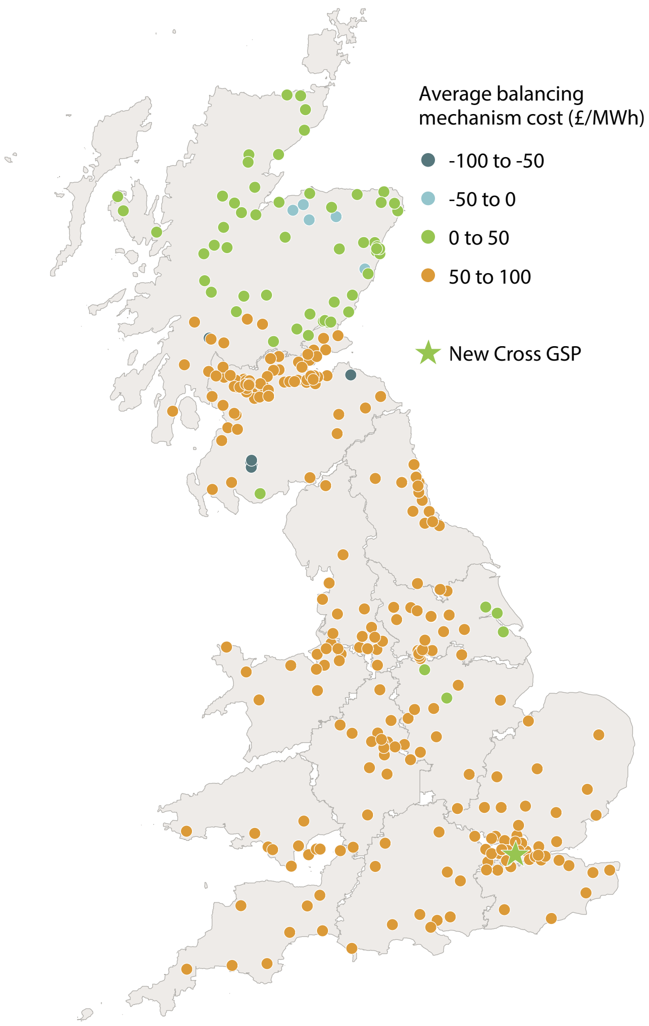

Figure 1: Average balancing mechanism price of Grid Supply Points in the UK. We have used a red rectangle to highlight the three GSPs in the Scottish Borders (Savelli, Hardy, Hepburn, & Morstyn, 2022).

A.i Smart local energy systems

Electrification of heating via heat pumps (HPs) and transportation via electric vehicles (EVs) is one category of option for decarbonisation, since electricity production becomes less carbon-intensive with the installation of renewables. However, the existing electricity network infrastructure in some areas of the Scottish Borders may not have sufficient capacity to host high renewable generation, as well as electric heating/transportation demand. From a transmission network perspective, the Scottish Borders is also a region where generation and demand-flexibility are valuable. Figure 1 provides a map showing the average balancing mechanism price of different Grid Supply Points (GSPs) in the UK (Savelli, Hardy, Hepburn, & Morstyn, 2022). The UK balancing mechanism plays an important role in supply-demand balancing and managing transmission congestion. We can see that the balancing prices are relatively high for all 3 GSPs in the Scottish Borders, indicating the value of flexibility.

A straightforward solution is electricity grid reinforcement, which, however, could require prohibitively high financial investments. A SLES could be an economic solution. SLES can help achieve the government target of net-zero by enabling value from small-scale smart technologies. Within the EnergyRev research consortium, our team focuses on unlocking the benefits of SLES by studying new market designs and proposing innovative business models that can be scaled out across the UK and internationally.

As is illustrated in the diagram of Figure 2, a SLES has the following three key elements:

- **Energy system**: It is a system incorporating everything from production, conversion, transmission, storage, distribution, and consumption.
- **Smart**: There are information and communication technologies supporting highly efficient energy system planning and optimised operation.
- **Local**: The energy system design and operation focus on local community needs, capabilities, and co-benefits. Localness can lead to fewer losses and transportation costs since the generation is geographically close to consumption.

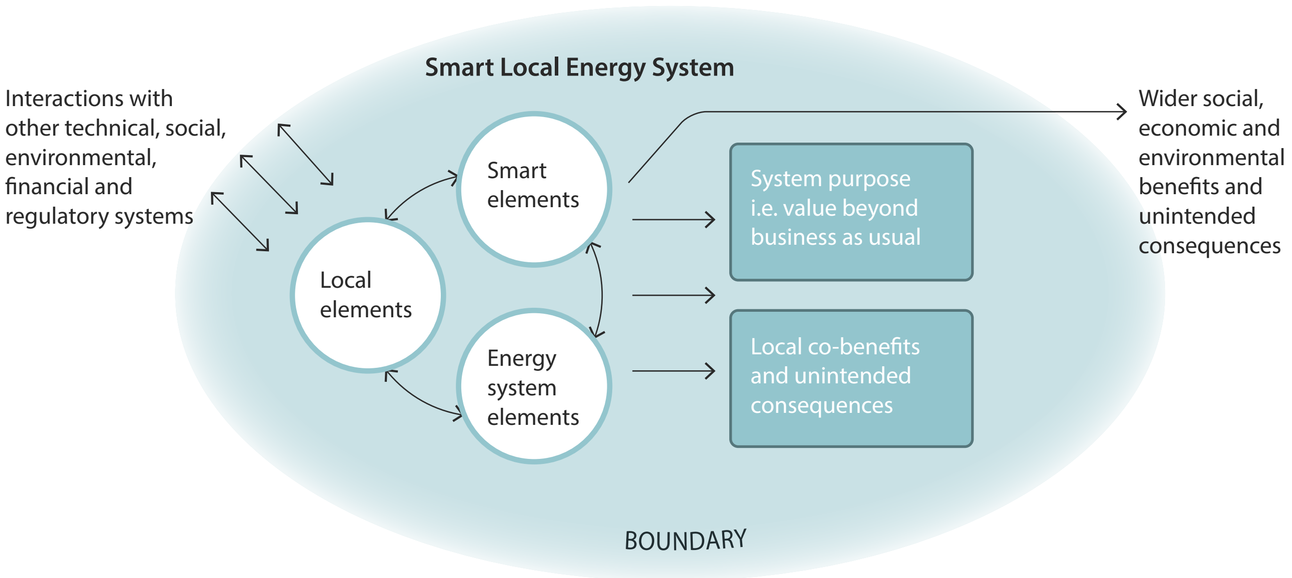

Figure 2: Components of SLES (Ford, Maidment, Fell, Vigurs, & Morris, 2020)

For the Scottish Borders, SLES can be applied to coordinate various locally distributed energy units, such that the risks caused by electrification of heating and transportation can be moderated. SLES can also coordinate local energy units to match the spike generation of renewables (e.g., the spike of wind and solar generation), which then improves the renewable hosting capacity.

A.i.a Local flexibility market

The SLES option evaluated in this report is the Local Flexibility Market (LFM). LFM is a market where the Distribution Network Operator (DNO)[1] can buy flexibility from various local energy resources (LERs) e.g., HPs and EVs. A simple example of the structure of LFM is given in Figure 3, a simplified version from Designing Decentralized Markets for Distribution System Flexibility (Morstyn, Teytelboym, & McCulloch, IEEE Transactions on Power Systems, 2019) . The flexibility of an energy resource refers to its ability to reduce/increase consumption/generation. In the market, the DNO can negotiate a set of flexibility contracts for each LER, each representing a reduction/increase of demand/generation at a particular period. The DNO can utilise the flexibility for various purposes, like reducing the peak demand to reduce the network upgrade costs, or making the demand better match renewable generation spikes to enable more renewable connections. LFM is now an emerging technology that DNOs are adopting in the UK (Piclo, 2022).

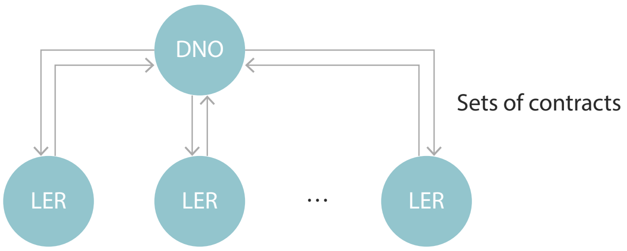

Figure 3: A simplified structure of a LFM between DNO and various LERs. In the market, DNO can negotiate a set of flexibility contracts of each LER, each representing a reduction/increase of demand/generation at a particular period.

A.ii Seasonal thermal energy storage

There are a number of types of Seasonal Thermal Energy Storage (STES) which are used to store heat for long periods from weeks to months, and are categorised as above or below ground, see Figure 4. The STES options explored in this analysis require connections to a district heating network.

Above ground

- Tank – typically of metal construction and externally lagged
- Pit – typically utilising space excavated previously for quarrying activities

Below ground

- Borehole – reliant upon ground types and permeability
- Aquifer – reliant upon existing subterranean flow rates and temperatures

STES can help manage the mismatch between the supply and demand of renewable energy systems which can occur over seasonal and inter-annual periods. It has often been installed to increase the utilisation of solar technologies which produce useful energy with a high degree of seasonal variability. However, solar thermal is not the only heat source which can be used. Multiple energy sources such as stochastic renewable power generation and waste heat can be utilised.

1 A distribution network operator (DNO) is the operator of the electric power distribution system which delivers electricity to most end users. For the Scottish Borders, the DNO is SP Distribution, a part of SP Energy Network.

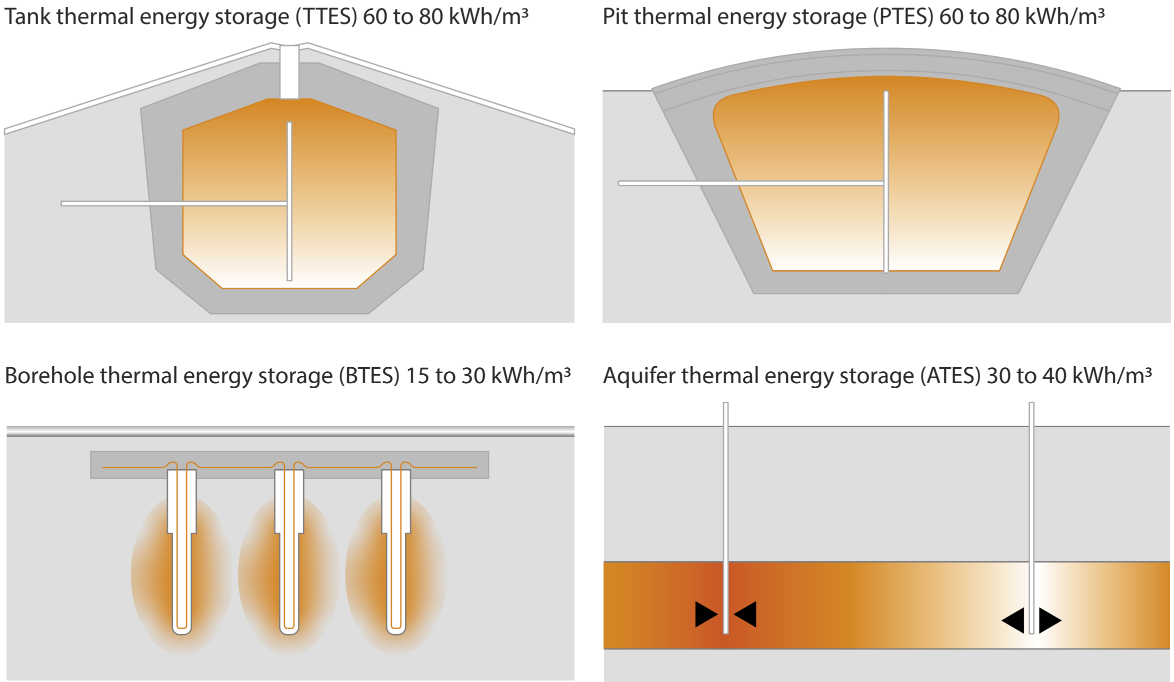

Figure 4: Schematic of different large-scale TES. Source Solites.

In the UK, there is an ongoing energy transition driving a growing installed capacity of wind power which is increasingly curtailed due to mismatch with demand or network constraints. Payments to wind farms to turn down generation in the UK have risen between 2015 and 2021 from £90 to £140 million (National Grid, 2022). Additionally, there is a large potential for untapped waste heat from the electricity generation sector, and the industrial and commercial sectors. The UK industrial sector alone is estimated to have a waste heat potential of 10-40 TWh/year (McKenna & Norman, 2010). It is possible that STES can provide value to the wider energy system by reducing the curtailment of wind power and using untapped waste heat.

A.iii Hydrogen

Hydrogen has been described as the "Fuel of the Future" since at least the 1970s; most of the basic principles of the technology were established even longer ago. Now, the possibility of actually using it is beginning to mature.

Given the 21st century requirement to remove carbon dioxide emissions, hydrogen has the potential to be used in a number of ways – any of which could be useful to SBC:

- As a vehicle (or railway engine, etc) fuel through a fuel cell. The fuel cell uses the reaction between hydrogen and oxygen to produce electricity, with the waste product being water (Cano, et al., 2018).
- As a vehicle fuel in a combustion engine. This replaces diesel or petrol in a similar type of engine (Eichlseder, Wallner, Freymann, & Ringler, 2003); it is possible in principle to convert an existing petrol engine to run on hydrogen (Page, 2021).
- As co-combustion in a diesel engine. Here hydrogen replaces up to 70% of the diesel fuel used – although less is currently standard – but does not replace it completely. This does allow the use of 100% diesel as a backup service provision (ULEMCo, 2022).

- In combustion for heating or industrial purposes, to replace natural gas (SGN, 2022).
- As an energy storage medium, where it can be produced using electricity and readily stored, then can be used to generate electricity (Scafidi, et al., 2021).

B. Project target

This project aims to provide an initial assessment of three categories of decarbonisation options (SLES, STES, and hydrogen) in alignment with the following targets:

- The net-zero goal: how could the options contribute to net-zero?
- Economic benefits: how could these options bring economic benefits for residents, the energy system and the council? We see two types of benefits:
    * For residents. This includes fuel poverty or fuel costs that are related to residents' interests.
    * For the energy system and council. This could be the network upgrade costs or other necessary financial investments that are related to the energy system and the council.
- Renewable hosting capacity: how could these options help increase the renewable hosting capacity?
- The feasibility/credibility of these options.

C. Evaluation metrics and organisation

We evaluate the SLES, STES, and hydrogen options to match these project targets. To do so, we have designed different evaluation metrics corresponding to each of the project targets, as listed in Table 1. The SLES options and associated scenarios are modelled and simulated using Open Platform for Energy Networks (OPEN), which is a Python-based toolset for modelling, simulation and optimisation of SLES (Morstyn, et al., 2020) .

Table 1: Evaluation metrics in alignment with the project targets.

Project targets	Evaluation metrics
Net-zero Target	Reduction in greenhouse gas/CO2 emission
Renewable Hosting Capacity	Maximum renewable installation capacity within grid limit
Residents' aspect	Impact on fuel poverty rate; fuel costs
Energy system and council's aspect	Estimation of financial cost of network upgrades; estimation of necessary financial investment.
Feasibility	Analysis of feasibility and mapping to the identified benefits

In the later content, the SLES options are organised into two parts, i.e., smart electric heating (Section II) and smart EV charging (Section III). In smart electric heating, two HP rollout options are evaluated first, and then a SLES option is introduced and evaluated. A similar structure is followed for EV charging. Section IV assesses the STES options, where the potential for installing STES under current and future scenarios are evaluated. The hydrogen options including vehicle refuelling and natural gas replacement are analysed in Section V. For each option, we provide a definition/description first, and then we conduct a case study to evaluate the metrics identified in Table 1. Depending on the characteristics of the options, the evaluation will be carried out on a local site, the overall Scottish Borders level, or both of them. Finally, we analyse the feasibility and summarise the benefits for each of the three categories of options: SLES, STES, and hydrogen in Section VI. Recommendations are also provided for the three categories of options.

2. Smart electric heating

A. Description of the option

A.i Electrification of heating

Electrification of heating via HPs is important to achieve the net-zero target. Although the current production of electricity emits greenhouse gas (GHG), its carbon intensity[2] is reducing with the increasing penetration of renewables. HP could also lead to lower bills due to its high efficiency. Based on the analysis carried out by Barnes and Bhagavathy, an HP can have a Seasonal Performance Factor (SPF)[3] between 2.5-4.1, meaning it can on average provide 2.5-4.1 kWh of heat by consuming only 1 kWh of electricity (Barnes & Bhagavathy, 2020). Such potential for lower heating bills is especially important for the Scottish Borders. Based on the Scottish House Condition Survey (SHCS) report (Scottish Government, 2019), the fuel poverty rate of SBC ranks 10th in the 32 council areas of Scotland. One reason could be its high non-gas rate (ranks 9th in Scotland (Scottish Government)). The more expensive non-gas heating options like LPG lead to a high fuel poverty rate. Overall, electrification of heating can benefit the Scottish Borders in both reaching the net-zero target and reducing fuel poverty.

A.ii Local flexibility market of heat pumps

The Scottish Borders may not have sufficient local network capacity to support the electrification of heating. In the content of SLES, it is possible to organise a local flexibility market (LFM) to exploit the flexibility of HPs. The flexibility of HPs comes from the fact that the indoor temperature within a small band (e.g., 1 degree) of users' set point is acceptable, meaning HPs can be flexible in terms of delaying their demand for a short period. One HP cannot provide the flexibility needed by the local network, but the coordination and the aggregation of a significant number of HPs can provide the flexibility that matches the scale of the local network. In this study, we evaluate two benefits of the HPs' flexibility exploited by LFM that are related to stakeholder concerns: peak demand reduction and renewable hosting capacity improvement.

A.ii.a Peak demand reduction

When a local flexibility market organiser, like a DNO, forecasts a high demand peak that could threaten the local distribution network, they can seek flexibility products in the market. As illustrated in Figure 3, there could be a negotiation process between the DNO and households with HPs, which leads to a mutual agreement on a set of flexibility contracts. Households with HPs then provide the flexibility as specified by the contract by turning off their HPs for a short time. By doing so, the DNO can successfully reduce the peak demand and the end-users could gain profits from the flexibility offers. The peak demand reduction enables the existing network to host more demand and reduce the financial costs of network upgrades.

2 Carbon intensity refers to the amount of GHG emissions per unit of energy production.

3 HPs' efficiency is dependent on the source temperature. SPF seeks to take the variability in performance over temperature ranges into account. It provides an assessment of the overall efficiency of an HP in use, over a given operating period. Therefore, when evaluating the annual heating costs of HPs, we use the SPF.

A.ii.b Renewable hosting capacity improvement

LFM can also increase the renewable hosting capacity. The demand and renewable generation cannot always be matched well. With the help of LFM, HPs now adjust their demand to better match the local renewable generation (especially the spike of renewable generation). The demand and generation are matched locally, such that the burden on the primary substation is released, and thus there could be more renewable installations.

B. Case studies

We evaluate smart heating scenarios for the local-site level and the overall Scottish Borders level. For the local-site level, Newcastleton serves as the case study. Newcastleton is a village in the Scottish Borders, which is not supplied by the gas grid (SGN Gas Network - Scotland, 2022). There is a need for a large-scale HP roll-out and a LFM based on these HPs to release the pressure on the local distribution network.

B.i. Electrification of heating

We first analyse the annual heating bills of different heating options in Figure 5, where we have made the following assumptions:

- "SEH" refers to storage electric heating while "Electric" refers to direct electric heating (Barnes & Bhagavathy, 2020). We assume that SEH follows the economic-7 tariff, with 90% of electricity consumed at a low price and 10% at a high price. Direct electric heating follows the standard fixed tariff.
- The HP has a SPF of 3.3, an average number of 2.5-4.1 based on the BEIS report (BEIS RHI Monthly Deployment, 2018). Gas, oil, and LPG boilers are assumed to have an efficiency of 90%, while coal boilers have an efficiency of 75% (Nottingham Energy Partnership, 2022). SEH and direct electric heating are assumed to have 100% efficiency (Barnes & Bhagavathy, 2020).
- We estimate the mean annual heating consumption per household to be 28427 kWh×87%=24731.49 kWh. The estimation is based on data from SHCS report (Scottish Government, 2019) that provides the mean household energy consumption and the percentage of energy consumption used for heating.
- The fuel price is based on an average over 2017-2019 to match the SHCS fuel poverty data. The 2017-2019 data is extracted from the BEIS report (BEIS RHI Monthly Deployment, 2018).

From Figure 5, we can see that HP is slightly more expensive than gas heating. However, it is cheaper than all the other options including coal, oil, LPG, and two types of electric heating. Therefore, the electrification of HPs could lead to a lower fuel poverty rate, which will be evaluated next.

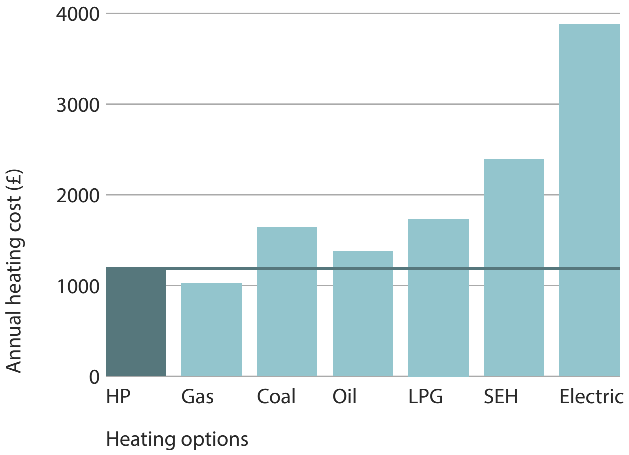

Figure 5: The annual cost of different heating options. The blue line indicates the annual heating cost of HP, which is plotted for better comparison.

B.i.a Fuel poverty

In this report, we judge a household to be in fuel poverty if its annual fuel cost for heating is greater than 10% of its annual net income.[4] Detailed method for estimating the fuel poverty rate is given in Appendix A.

Fuel poverty in Newcastleton

Based on the 2011 Census data (Scotland's Census, 2011), the proportion of households using different types of fuels for heating in Newcastleton is plotted in Figure 6. Note that, in the Census data, there are 2.1% of households without central heating and 9.4% using two or more types of heating sources. We remove these proportions to simplify the analysis. Also, 9.6% of households in Newcastleton use natural gas central heating based on the Census data, but data from the Scottish Gas Network (SGN Gas Network - Scotland, 2022) shows that the gas pipeline is far away from Newcastleton. We therefore deduce that the Census data has some errors, which could be caused by people using bottled-gas heating choosing the "gas" option by mistake. We therefore assume these 9.6% natural gas-heating households have LPG-heating.

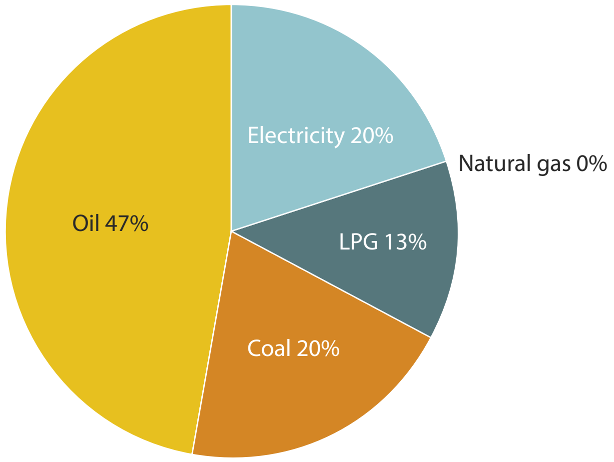

Figure 6: The proportion of households using different heating fuels in Newcastleton.

Table 2 lists the estimated fuel poverty rate in Newcastleton under three options. "Current" refers to its current fuel poverty rate estimation. "HP Rollout Non-gas" refers to replacing all the non-gas heating with HPs, and "HP Rollout All" means replacing all the heating options including gas heating. Since Newcaslteton has no gas connection, these two HP rollout options are the same and the entry for "HP Rollout All" in Table 2 is marked as "-". We see that the HP rollout can significantly reduce the fuel poverty rate in Newcastleton. Under "HP Rollout Non-gas", 29.2% of fuel-poor households are pulled out of fuel poverty.

Table 2: The estimated fuel poverty rate in Newcastleton under the current estimation and two HP rollout options. Since Newcastleton has no gas connection, these two HP rollout options are the same and the entry for "HP Rollout All" is marked as "-".

Option	Current	HP Rollout Non-gas	HP Rollout All
Fuel Poverty Rate	49.87%	35.32%	-

4 Based on the up-to-date definition of fuel poverty in Scotland (Fuel Poverty (Targets, Definition and Strategy) (Scotland) Act, 2019), a household is considered in fuel poverty if i) the fuel cost is greater than 10% of their adjusted net income, and ii) the remaining income is insufficient to maintain an acceptable standard for living. Due to the lack of data, we consider a household in fuel poverty based on the "10%" condition only.

Fuel poverty in the Scottish Borders

A similar analysis is done for the overall Scottish Borders' level and the results are given in Table 3. The two HP rollout options can also lead to a lower fuel poverty rate in the overall Scottish Borders. For "HP Rollout Non-gas", the fuel poverty rate drops to 21.8%, meaning about 25.6% of fuel-poor households are pulled out of fuel poverty. Note that, based on 2017-2019 price data, gas heating is cheaper than HPs, so if we substitute all the heating options including the gas heating with HPs, the fuel poverty rate drops less significantly to 25.00%. This result will depend on future electricity prices and on carbon tariffs which may in future be applied to gas, which could make natural gas more expensive than HPs. At least currently, "HP Rollout Non-gas" is a more economic option for fuel poverty reduction than "HP Rollout All".

Table 3: The estimated fuel poverty rate in the Scottish Borders under the current estimation and two HP rollout options.

Option	Current	HP rollout non-gas	HP rollout all
Fuel Poverty Rate	29.30%	21.80%	25.00%

B.i.b Green house gas emission evaluation

Another benefit of HP is its smaller carbon intensity, i.e., the greenhouse gas emission (GHG) emission per kWh heat. The carbon intensity for fuel-based heating, including natural gas, is almost fixed (although it could be slightly reduced due to the increase in boiler efficiency). In comparison, electrified heating can gradually reduce its emission to zero due to the increasing installation of renewables. The UK National Grid provides forecasts for the UK electricity carbon intensity up to 2050 [5](ESO Future Energy Scenarios, 2021). The Department for

Business, Energy & Industrial Strategy in UK provides the carbon intensity of other heating fuels (DESNZ and BEIS, 2020). Combined with the mean annual household heating demand and the number of households data (available in (Scotland's Census, 2011)), we can estimate the annual GHG emission of an area.

GHG emission in Newcastleton

Since electrified heating leads to different emissions under different electricity generation mixes, we estimate and compare the total yearly GHG emissions by heating under three possible electricity carbon intensities: current carbon intensity, forecasted carbon intensity in 2030, and forecasted carbon intensity in 2050. The results are summarised in Table 4. One can see that both HP rollout options can reduce carbon emissions significantly. For "HP Rollout Non-gas", the carbon reduction is less, but is still up to 90% under the 2050 electricity carbon intensity.

5 Note that there are two kinds of electricity carbon intensity forecasts in(ESO Future Energy Scenarios, 2021). One includes negative emissions from Bioenergy with Carbon Capture and Storage (BECCS) while the other excludes it. We use the latter one as we only consider the emission from the electricity and the potential carbon capture is excluded. The one that excludes BECCS also includes four scenarios where three of them achieve net-zero. We pick the maximum electricity carbon intensity of the three scenarios that achieve the net-zero to give a relatively conservative estimation.

Table 4: Comparison of the estimated total yearly GHG emissions by domestic heating in Newcastleton under three possible electricity carbon intensities.

Option	Current electricity carbon intensity	2030 electricity carbon intensity	2050 electricity carbon intensity
No HP	2778.2 ton	2554.0 ton	2500.2 ton
HP Rollout Non-gas	610.3 ton	301.8 ton	227.7 ton
HP Rollout All	448.1 ton	102.1 ton	19.0 ton

Green house gas emission evaluation for SBC

A similar analysis is done for the overall Scottish Borders (Table 5). The HP rollout of non-gas heating has a modest impact with 32% reduction given current electricity carbon intensity. This is because gas is the main contributor to GHG emissions in the Scottish Borders. However, a HP roll-out for all heating including gas leads to less fuel poverty reduction, and requires much more upfront investment. Other clean energy can also lead to the same environmental benefit. Existing gas boilers are already able to accept a mixture of up to 20% hydrogen and natural gas. Hydrogen-ready boilers which can accept 100% hydrogen are under development, but are expected to reach a similar upfront cost as gas boilers, which is much less than that of HPs (Worcester Bosch, 2022). Therefore, in future, replacing gas heating with hydrogen could be more economic than replacing natural gas heating with HPs.

Table 5: Comparison of the estimated total yearly GHG emissions by domestic heating in the Scottish Borders under three possible electricity carbon intensities.

Option	Current electricity carbon intensity	2030 electricity carbon intensity	2050 electricity carbon intensity
No HP	0.286 MT	0.261 MT	0.255 MT
HP rollout non-gas	0.192 MT	0.175 MT	0.171 MT
HP rollout all	0.061 MT	0.014 MT	0.003 MT

B.i.c Network upgrade cost

We have seen that the HP rollout can lead to lower fuel poverty as well as lower carbon emissions. However, the local electricity network may need to be upgraded to host the higher peak demand, which could lead to a heavy financial burden.

SPEN DFES provides forecasts of the possible number of HPs that will be connected to the local primary substations in Newcastleton under several possible future scenarios to achieve the net-zero target. From the scenarios, we find the maximum (high scenario) and the minimum number of HPs (low scenario) in 2030 and 2050. Based on the recommendation by (Hao, Sanandaji, Poolla, & Vincent, 2015), the rated power of domestic HP[6] is set to be 5.6 kW with a coefficient of performance of 2.5, which is smaller than the 3.3 used in Section II.B.i.

6 Here we consider domestic HPs only.

This is because HPs suffer lower efficiency when the source temperature is low, while the 3.3 used in Section II.B.i. is SPF that represents an average efficiency for temperature ranges. HPs are assumed to have a temperature set point at 19 , the same setting as the work in (Morstyn, et al., 2020).

We simulate the peak demand and, further, the network upgrade cost via methods outlined in Appendix B. The estimated peak demand under different HP scenarios is plotted in Figure 7, where we use a red horizontal line to represent the local primary substation capacity limit[7] (SP Energy Networks, 2022). Bars exceeding the capacity indicate the need to upgrade the local primary substation. It can be observed that the local primary substation needs to be upgraded in 2030 under the high uptake scenario. Note that the number of HPs in the "2050 low" scenario is higher than that in the "2030 high" scenario.

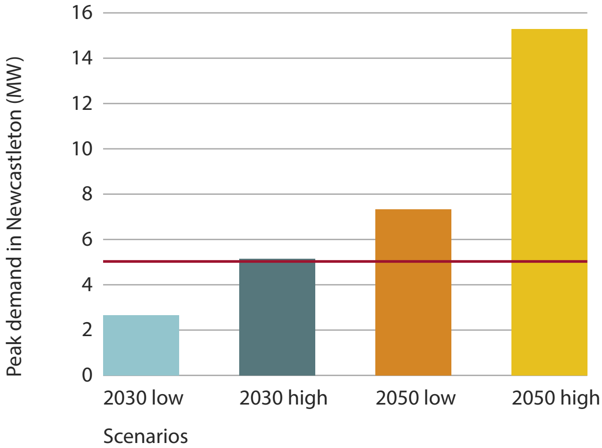

Figure 7: Peak demand in the Newcastleton primary substation under the minimum and maximum number of HPs in 2030 ("2030low"/"2030high") and 2050 ("2050low"/"2050high"). The red horizontal line indicates the capacity limit of the primary substation.

We further estimate the upgrade cost for the primary substations where the peak demand exceeds the capacity limit[8] as in Table 6, where the estimation method is given in Appendix B.ii. To get the results for the overall Scottish Borders, we sum up the upgrade costs of all the primary substations within the Scottish Borders, where the calculation method of upgrade cost for each primary substation is exactly the same as the Newcastleton case. The capacity limit of all the primary substations in the Scottish Borders comes from (SP Energy Networks, 2022). Note that, in this report, we consider the upgrade costs for primary substations only. The upgrade could also be necessary for Grid Supply Points and substations at other levels, which require more data for analysis.

From Table 6, we see that the upgrade cost for Newcastleton and the overall Scottish Borders could be up to £24.29K k£ and £30.26M in 2030, a high financial burden for SBC.

Table 6: Estimated upgrade cost for Newcastleton primary substation and the overall Scottish Borders to host different HP demands. "-" means there is no need for an upgrade.

Scenario	2030 low	2030 high	2050 low	2050 high
Newcastleton	-	£24.29K	£548.62K	£2419.47K
Scottish Borders	£6.54M	£30.26M	£61.41M	£138.43M

7 Note that, in the HP case, the demand of EV is not considered.

8 Note that even if the demand is within the capacity limit, it may be still necessary to upgrade the existing cables. However, this is much less costly than upgrading the primary substations, so we exclude this part in our analysis. Also, we do not consider voltage limits and reactive power compensation.

B.ii Local flexibility market for HPs

B.ii.a Reduction in network upgrade cost

As discussed in Section II.A.ii, HPs are "flexible" in terms of controlling the indoor temperature within a small band of the users' set points. Therefore, it is possible to reduce the network peak demand and thus the upgrade costs by organising a LFM based on the HPs' flexibility. As an example, HPs can slightly "overheat" the house in advance, and then the heating power over the time of the peak demand can be reduced. Here we consider the temperature is allowed within ±1 ºC of the set point, i.e., 18 to 20º. Other parameters are the same as Section II.B.i.c, and we use the OPEN platform (Morstyn, et al., 2020) to simulate the peak demand after the introduction of a LFM.

Figure 8 illustrates the peak demand after the introduction of LFM. Compared to Figure 7, the upgrade of the local primary substation in 2030 is avoided with the help of LFM.

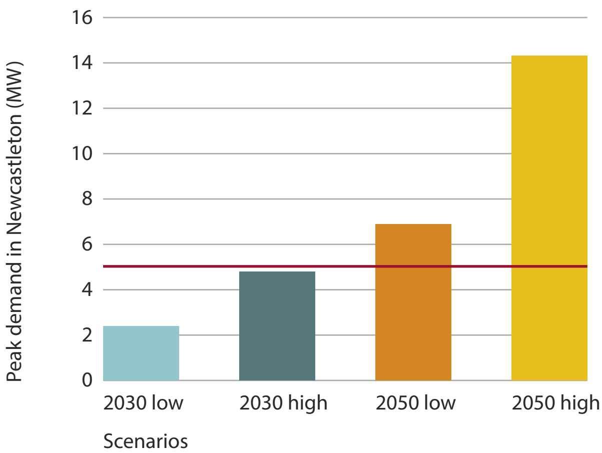

Figure 8: Peak demand in the Newcastleton primary substation under the minimum and maximum number of HPs in 2030 ("2030low"/"2030high") and 2050 ("2050low"/"2050high") after the introduction of HP-based LFM. The red horizontal line indicates the capacity limit of the primary substation.

Table 7 and Table 8 summarise the upgrade cost of primary substations and the reduction rate (compared to no LFM in Table 6) after the introduction of an HP-based LFM. The results for the Scottish Borders is the summation of the results in all the primary substations. For Newcastleton, 100% upgrade cost (£24.29K) for hosting the HP demand is saved in the "2030 high" scenario. The financial savings are also significant in the latter two 2050 scenarios. For the Scottish Borders, the financial saving in network upgrades could be £1.38M (21.1% reduction rate) and £4.14M (13.7% reduction rate) for the two 2030 scenarios respectively, which are still considerable. Note that the reduction rate becomes less when there are more HPs. This is because network upgrades are harder to avoid when there is too much HP demand, despite the flexibility created through the LFM.

Table 7: Estimated upgrade cost and reduction rate (compared to no LFM in Table 6) after the introduction of LFM in Newcastleton primary substation. "-" means there is no need for an upgrade. The reduction rate in "2030 low" is zero as the local primary substation does not need an upgrade before the introduction of LFM.

Scenario	2030 low	2030 high	2050 low	2050 high
Upgrade Cost	-	-	£450.00K	£2192.78K
Reduction Rate	0%	100%	21.9%	9.4%

Table 8: Estimated upgrade cost and reduction rate (compared to no LFM in Table 6) after the introduction of LFM in the Scottish Borders. "-" means there is no need for an upgrade.

Scenario	2030 low	2030 high	2050 low	2050 high
Upgrade Cost	£5.16M	£26.12M	£55.63M	£127.15M
Reduction Rate	21.1%	13.7%	9.4%	8.15%

B.ii.b Renewable hosting capacity

LFM can also help improve the renewable hosting capacity. The renewable hosting capacity refers to the maximum renewable generation that can be installed within the network capacity limit. Improving the hosting capacity reduces the network upgrades required to install more renewables. The detailed method for calculating the renewable hosting capacity is given in Appendix C. Also, note that similar to the upgrade cost evaluation, the evaluation here only considers the renewable hosting capacity connected to the primary substations. Renewables can also be connected to substations at other levels like GSPs.

With LFM, the HP demand can be shifted to the time when renewables have spike generation. The generation and demand are matched locally, which reduces the burden on the local primary substations. In this report, we evaluate two typical renewables, wind and solar.

Renewable hosting capacity in Newcastleton

Similar to the peak demand reduction case, we evaluate the renewable hosting capacity for wind and solar generation under different numbers of HPs. The results are given in Table 9 and Table 10.[9] We see that LFM does lead to an increase in renewable hosting capacity in the local primary substation for both wind and solar generation, which thus saves the costs for upgrading the network to host more renewables.

The increase in solar generation is higher, as solar generation could be less fluctuant compared to wind and is easier to offset locally. The effect of LFM becomes stronger when there are more HPs due to the higher flexibility.

Table 9: Wind hosting capacity in Newcastleton primary substation under four scenarios (corresponding to the lowest/highest number of HPs in 2030 and 2050). The number in the parenthesis is the increase rate compared to "No LFM".

Scenario	2030 low	2030 high	2050 low	2050 high
No LFM	7.04 MW	8.91 MW	12.73 MW	26.16 MW
After LFM	7.24 MW (2.8%)	9.35 MW (5.0%)	13.37 MW (5.0%)	27.57 MW (5.4%)

9 Note that when there is no LFM, the local network may not be able to host too many HPs even with local renewable generation, since they cannot be properly offset without the coordination of LFM. Therefore, we assume the network has been upgraded to host the HP demand when it exceeds the original capacity limit.

Table 10: Solar hosting capacity in Newcastleton primary substation under four scenarios (corresponding to the lowest/highest number of HPs in 2030 and 2050). The number in the parenthesis is the increase rate compared to "No LFM".				
Scenario	**2030 low**	**2030 high**	**2050 low**	**2050 high**
No LFM	7.35 MW	9.45 MW	13.41 MW	27.40 MW
After LFM	7.74 MW (5.0%)	10.23 MW (8.0%)	14.64 MW (8.4%)	30.07 MW (8.9%)

Renewable hosting capacity in the overall Scottish Borders

Table 11 and Table 12 show the results for the overall Scottish Borders, which on a percentage basis are similar to the Newcastleton case. The results for the Scottish Borders is the summation of the results for all the primary substations.

Table 11: Wind hosting capacity in the Scottish Borders under four scenarios (corresponding to the lowest/highest number of HPs in 2030 and 2050). The number in the parenthesis is the increase rate compared to "No LFM".				
Scenario	**2030 low**	**2030 high**	**2050 low**	**2050 high**
No LFM	365.06 MW	561.65 MW	791.21 MW	1356.79 MW
After LFM	378.06 MW (3.6%)	588.84 MW (4.8%)	830.04 MW (4.9%)	1426.57 MW (5.1%)

Table 12: Solar hosting capacity in Scottish Borders under four scenarios (corresponding to the lowest/highest number of HPs in 2030 and 2050). The number in the parenthesis is the increase rate compared to "No LFM".				
Scenario	**2030 low**	**2030 high**	**2050 low**	**2050 high**
No LFM	398.31 MW	603.48 MW	841.19 MW	1429.07 MW
After LFM	417.60 MW (4.8%)	649.09 MW (7.6%)	911.73 MW (8.4%)	1561.45 MW (9.3%)

3. Smart EV charging

A. Description of the option

With a ban on the sale of new petrol and diesel vehicles from 2030 in the UK, the need to support an EV future is more pressing than ever. The introduction of EVs is important to achieve the net-zero target, due to the reducing carbon emissions of producing electricity.

Like HPs, EV integration could also threaten the distribution network, and we understand that EVs will need an extensive and reliable power network to meet the demand for charging. Compared to investing more in network reinforcement, which could be prohibitively expensive, wisely managing the EV demand by SLES is a more economical solution, since some EVs have longer parking periods than their charging periods. The LFM can exploit their flexibility, or ability to delay charging. We will evaluate the benefits of EV engagement within a LFM in terms of reduced peak demand, which leads to lower network upgrade cost, and increased renewable hosting capacity.

B. Case studies

Case studies are carried out for both the local-site and overall Scottish Borders levels. Charlesfield is chosen as the local site for evaluation. Charlesfield is close to the principal depot of the vehicle fleet owned by the SBC. There is likely to be a fleet of electric vehicles and thus the need for smart charging. However, as this is a comparably small region, its nearest primary substation is in St. Boswell. Therefore, in the case study, we focus on evaluating how the increasing number of EVs will affect the St. Boswell primary substation.

B.i EV rollout

B.i.a GHG emissions

The main benefit of EVs is carbon emission reduction. We plot the carbon intensity of EVs and conventional vehicles (CVs) in Figure 9. Here the carbon intensity is defined as the amount of GHG emissions per mile. As we can see, EVs have significantly lower carbon intensity than CVs, even under the current electricity carbon intensity. As the renewable penetration increases, the reduction rate will grow towards 100% in 2050.

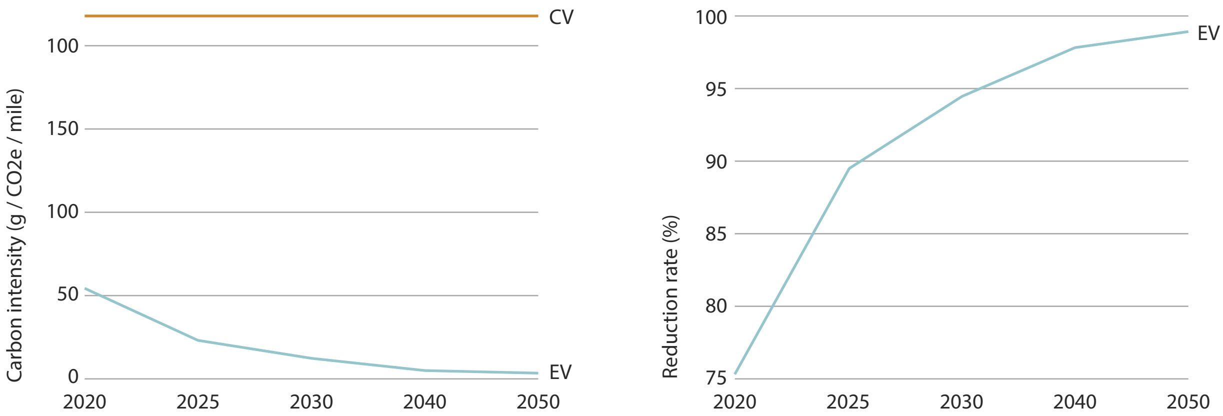

Figure 9: Left: the GHG emissions per mile of EVs and CVs under the electricity carbon intensity in different years; Right: The carbon reduction rate of EVs compared to CVs.

B.i.b Network upgrade cost

EVs could threaten the local network and require significant investment in network upgrades to host the EV charging demand. Similar to the HP case, SPEN DFES also provides forecasts of the possible number of EVs that will be connected to the local primary substations under three possible scenarios to achieve the net-zero target. From the scenarios, we find the maximum (high scenario) and minimum number of EVs (low scenario) in 2030 and 2050, and plot the peak demand under these four cases in Figure 10.[10] Note that the number of EVs in the "2050 low" case is higher than that in the "2030 high" case. Here the demand is the summation of the base demand (current demand connected to the primary substation from SPEN DFES and the EV charging demand. Detailed description of method is given in Appendix B. We assume half of the EVs follow the "day charge" pattern, e.g., EVs charging at the working place. The other half of the EVs is assumed to follow the "night charge" pattern, e.g., EVs charging at home overnight. In the "day charge" pattern, EVs are assumed to arrive at around 9:00 a.m.[11] and depart at around 5:00 p.m. In the "night charge" pattern, EVs are assumed to arrive at about 7:00 p.m. and depart at 8:00 a.m. the next day. We set the EV charging power to 6.6 kW and their battery size to 36 kWh. Their State of Charge (SOC) at the time of arrival is randomly picked from 20% to 60% of their maximum energy levels. All the EVs are required to be charged to at least 90% of their maximum energy level. We suppose all the EVs start charging immediately when they arrive. These parameter settings come from the research work in (Morstyn, et al., 2020).

From Figure 10, we observe an upgrade is required for St. Boswell primary substation to host the EV demand in the "2030 high" scenario. The estimated upgrade costs for both St. Boswell and the overall Scottish Borders are also summarised in Table 13. The method for estimating the upgrade cost is the same as the HP case (Appendix B.ii). The results for the Scottish Borders is the summation of the results for all the primary substations. Note that, in this report, we consider the upgrade costs for primary substations only. Upgrade could also be necessary for Grid Supply Points and substations at other levels, which require more data for analysis.

10 Note that, in the EV case, the HP demand is not considered.

11 We say "around" as the arrival/departure time will be randomly picked around the specified time to make our simulation more realistic.

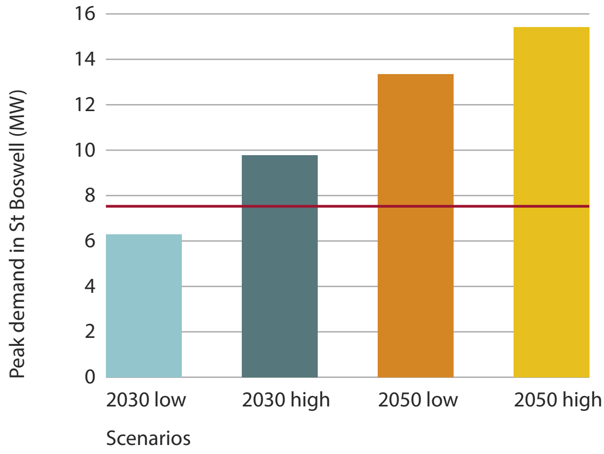

Figure 10: Peak demand under the minimum and maximum number of EVs in 2030 ("2030low"/"2030high") and 2050 ("2050low"/"2050high") in St. Boswell primary substation. The red horizontal line indicates the capacity limit of the primary substation.

Table 13: Estimated upgrade cost for St. Boswell primary substation and the overall Scottish Borders. "-" means there is no need to upgrade the primary substation.

Scenario	2030 low	2030 high	2050 low	2050 high
St. Boswell	-	£534.44K	£1391.26K	£1890.03K
Scottish Borders	£1.62M	£10.24M	£25.71M	£33.63M

B.ii Local flexibility market of EVs

B.ii.a Network upgrade cost

As mentioned, EVs could have longer parking periods than their charging periods, meaning they have the "flexibility" to move their charging demand to other periods. A LFM can be organised to reduce the peak demand by utilizing the EVs' flexibility and moving their charging from the peak time to other slots. The EV parameter settings are the same as Section III.B.i.b. V2G is not considered here. Although it could lead to higher benefits, it may be harmful to the batteries so it is not clear whether EV users will accept it. Also, note that we only consider two EV parking patterns, i.e., the "day charge" pattern and the "night charge pattern" as Section III.B.i.b, in both of which EVs can have long parking periods. In the real world, some EVs may have short parking periods and thus have lower flexibility. In this high-level evaluation report, we do not consider this case and thus the estimated benefits of EVs' flexibility may be overestimated to some extent.

The peak demand after the introduction of LFM in the St. Boswell primary substation is plotted in Figure 11. Surprisingly it is found that there are no upgrade requirements for hosting the EV charging demand in the St. Boswell primary substation up to 2050.

The estimated upgrade cost to host the EV demand for the overall Scottish Borders is given in Table 14. The results for the Scottish Borders is the summation of the results for all the primary substations. The upgrade for the St. Boswell primary substation is avoided for all the scenarios after the introduction of LFM, indicating 100% cost reduction and is thus not explicitly listed as a table here. From the perspective of the overall Scottish Borders, the upgrade cost reduction rate is also close to 100%. Comparing the results with Section B.ii.a, it can be seen that EVs offer more flexibility than HPs.

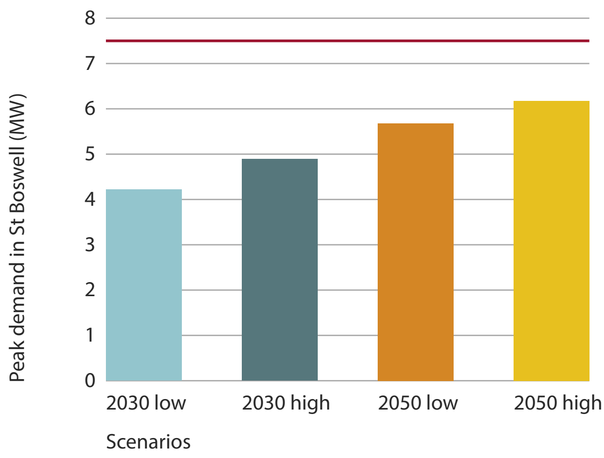

Figure 11: Peak demand in the St. Boswell primary substation under the minimum and maximum number of EVs in 2030 ("2030low"/"2030high") and 2050 ("2050low"/"2050high"). The red horizontal line indicates the capacity limit of the primary substation.

Table 14: Estimated upgrade cost and reduction rate after the introduction of LFM in the Scottish Borders. "-" means there are no primary substations to be upgraded.

Scenario	2030 low	2030 high	2050 low	2050 high
Upgrade Cost	-	£0.004M	£0.58M	£1.22M
Reduction Rate	100%	99.96%	97.74%	96.37%

B.ii.b Renewable hosting capacity

A LFM can also leverage EVs' flexibility to increase the local renewable hosting capacity. For example, the EVs' normal charging demand may not match the renewable generation well, but a LFM could move the EV charging demand to times when there is excess renewable generation. The local offset of demand and generation thus leads to a smaller burden on the local primary substation. The estimation method for the renewable hosting capacity is the same as the HP case and is given in Appendix C. Also, note that similar to the upgrade cost evaluation, the evaluation here only considers the renewable hosting capacity connected to the primary substations. Renewables can also be connected to substations at other levels like GSPs.

The wind/solar hosting capacity before and after the introduction of LFM is listed in Table 15-Table 18. The results for the Scottish Borders is the summation of the results in all the primary substations. With the introduction of LFMs, the renewable hosting capacity sees a significant increase, which is also much higher than the HP case. This result further demonstrates the higher flexibility of EVs compared to HPs. Utilizing the flexibility of EVs can provide greater benefits to the local systems. The customers (EV owners) can also benefit more from selling the flexibility.

Renewable hosting capacity in the St. Boswell Primary Substation

Table 15: Wind hosting capacity in St. Boswell primary substation under four scenarios (corresponding to the lowest/highest number of EVs in 2030 and 2050). The number in the parenthesis is the increase rate compared to "No LFM".

Scenario	2030 low	2030 high	2050 low	2050 high
No LFM	10.52 MW	12.87 MW	16.58 MW	18.75 MW
After LFM	12.27 MW (16.7%)	16.50 MW (28.3%)	22.01 MW (32.7%)	25.50 MW (36.0%)

Table 16: Solar hosting capacity in St. Boswell primary substation under four scenarios (corresponding to the lowest/highest number of EVs in 2030 and 2050). The number in the parenthesis is the increase rate compared to "No LFM".

Scenario	2030 low	2030 high	2050 low	2050 high
No LFM	12.46 MW	15.46 MW	19.71 MW	22.20 MW
After LFM	14.27 MW (14.6%)	19.86 MW (28.5%)	26.62 MW (35.1%)	30.75 MW (38.5%)

Renewable hosting capacity for the overall Scottish Borders

Table 17: Wind hosting capacity in the Scottish Borders under four scenarios (corresponding to the lowest/highest number of EVs in 2030 and 2050). The number in the parenthesis is the increase rate compared to "No LFM".

Scenario	2030 low	2030 high	2050 low	2050 high
No LFM	283.36 MW	321.13 MW	388.58 MW	422.80 MW
After LFM	320.39 MW (13.1%)	393.59 MW (22.6%)	501.92 MW (29.2%)	555.76 MW (31.4%)

Table 18: Solar hosting capacity in the Scottish Borders under four scenarios (corresponding to the lowest/highest number of EVs in 2030 and 2050). The number in the parenthesis is the increase rate compared to "No LFM".

Scenario	2030 low	2030 high	2050 low	2050 high
No LFM	327.64 MW	380.51 MW	460.44 MW	500.38 MW
After LFM	363.98 MW (11.1%)	464.61 MW (22.1%)	600.21 MW (30.4%)	666.16 MW (33.1%)

4. Seasonal thermal energy storage

A. Description of the option

This section looks at the potential for installing seasonal thermal energy storage (STES) for district heating in the Scottish Borders. This analysis is limited to total system costs which consist of capital costs and operational costs.

B. Case study

Galashiels is chosen as the location for modelling a district heating network. It has the highest heat demand density in the Scottish Borders area and includes several existing district heating networks, see Figure 12.

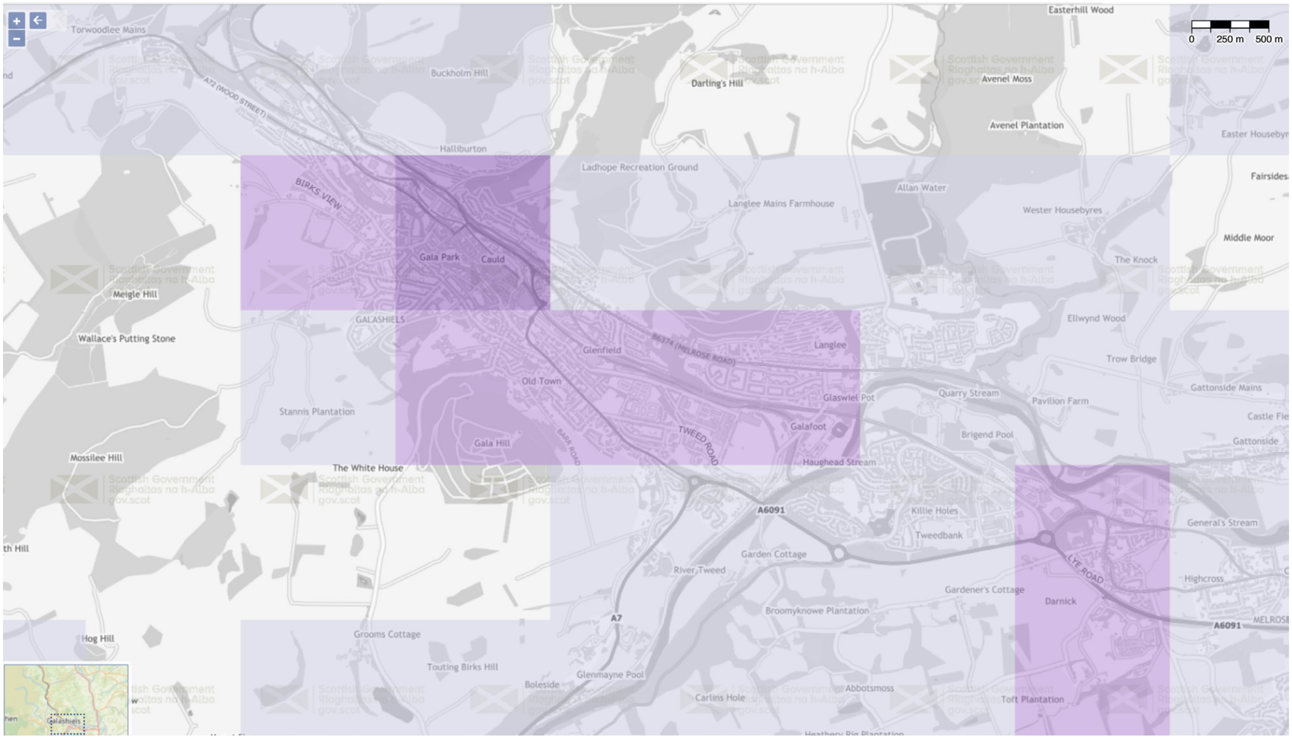

Figure 12: Heat demand and existing heat networks at Galashiels from the Scottish Heat Map.

For the purposes of this analysis an imagined 500 residential dwelling district heating scheme located at Galashiels is modelled.

Analysis is carried out in two steps: 1) scenario analysis to optimise operation and size of components using 2019 as a reference year, and 2) impact of future wind curtailment[12] using a discount based on the curtailed wind energy output from future energy scenario transmission network modelling (ESO Future Energy Scenarios, 2021).

In the first step the following scenarios, with different heat sources and storages for the district heating case study, are investigated:

1. Base case scenario of direct electric heating,
2. Direct electric heating + heat pump,
3. Direct electric heating + heat pump + short-term thermal energy storage,
4. Direct electric heating + heat pump + short-term thermal energy storage + STES,
5. All components of 4 + discount for curtailed wind from Crystal Lea II.[13]

In the second step the following future years are investigated for the STES scenario (scenario 4) in step 1:

1. Curtailed wind discount 2020
2. Curtailed wind discount 2030
3. Curtailed wind discount 2040
4. Curtailed wind discount 2050
5. Curtailed wind discount 2050 plus a 1 MW constraint on network

This analysis optimises the operation and size of components of the district heating case study, based on several input data and assumptions. Direct electric heater and heat pumps are the heat supply options. Short-term thermal storage and STES are the heat storage options. Heat and electricity demands are modelled based on a 500 residential dwelling district heating scheme. Wholesale electricity prices are calculated using the time-of-use Octopus Agile and Export tariffs (Octopus Energy, 2022).

Simulation is carried out for a single year, assuming 20-year lifespan of the components. Capital costs are assumed to be amortized over the 20-year lifespan, meaning the optimisation accounts for 1/20th of the capital cost in the simulation year. Table 19 below lists the modelling assumptions used in the simulation.

12 The curtailment is the deliberate reduction of power output that an electric generator performs to balance the supply with the demand.

13 60 Siemens 2.3 MW turbines are positioned predominantly to the west of the existing Crystal Rig wind farm.

Table 19: Modelling assumptions

Technology	Assumption
Direct electric heater	Efficiency = 1 Capital cost = £130k / MWth
Heat pump	Efficiency = Proportional to air temperature using data of Neatpump (Star Refrigeration, 2022) Capital cost = £400k / MWth
Short-term thermal energy storage	Charging rate = 2.94 MW Discharging rate = 1.26 MW Standing loss = 0.1% / hour Capital cost = £3k / MWh
Seasonal thermal energy storage (STES)	Charging rate = 0.6 MW Discharging rate = 0.6 MW Standing loss = 0.24% / hour Capital cost = £0.5k / MWh
Grid	Indicative wholesale electricity price calculated from Octopus agile and export tariffs
Heat demand	Modelled 500 dwelling district heating scheme using 2019 air temperature from (ECMWF, 2022)
Electrical demand	Modelled electrical demand of 500 dwellings using Elexon standard profiles and adding diversity by smoothing
Wind discount	For step 1 of the analysis 2019 curtailment payment data for Crystal Lea II (sourced from Elexon) is used to discount the electricity price. The discount price is equal to the £/MWh payment to the wind farm, and is assumed for all curtailment events, regardless of volume. For step 2 of the analysis modelled national wind curtailment from transmission model of the GB power system using National Grid's Future Energy Scenario is used to predict curtailment events (ESO Future Energy Scenarios, 2021). Future years are modelled using 2020 as the weather year. Curtailment events of volume above 1GW are used to discount wholesale electricity prices for 2020 by 50 £/MWh.

B.i Step 1

The base case scenario for this analysis is direct electric heaters, as currently most residential buildings in Galashiels use this form of heat supply (National Grid, 2022). Figure 13 shows that a combination of heat pump and direct electric heater reduces total system costs relative to the purely direct electric base case.

Figure 14 shows the optimal sizes that minimise the system costs of short-term and seasonal thermal storage. Total system cost optimisation of component sizing and operation is performed using a Python linear optimisation model built on PyPSA (Brown, Hörsch, & Schlachtberger, 2018). Adding short-term thermal energy storage further decreases total system costs, an increase in capital costs. Adding STES has negligible impact on this reference year. This is also the case with the curtailed wind discount scenario, as there are insufficient curtailment events to incentivise seasonal storage. The replacement of direct electric heaters with heat pumps and short-term thermal energy storage reduces total system costs by 49%, while adding STES further reduces total system costs by 1%.

The benefit of adding storage in this system is to flexibly operate the direct electric heater and heat pump components in response to fluctuations in wholesale electricity prices or wind curtailment events. These are typically intra-day fluctuations, with less variability on weekly or seasonal timescales, therefore the short-term thermal energy storage is sufficient to perform this application.

B.ii Step 2

It is expected in future years that wind curtailment events will be more frequent. PyPSA-GB is a model of the Great Britain power system including the network, loads, generation, and storage. It can model the Future Energy Scenarios set out by National Grid (ESO Future Energy Scenarios, 2021). PyPSA-GB is used to model future curtailment which is used to provide a discount to the electricity prices for the proposed district heating system. This step again optimises all components of scenario 4 from Step 1, i.e., direct electric heater+ heat pump + short-term thermal storage + STES, with different discounted electricity profiles.

Figure 15 shows that for the years 2030, 2040, and 2050 that a discount due to curtailment events gives overall negative costs. This means that the optimised system is able to operate the direct electric heater and heat pump at times of negative pricing, outweighing the cost of operating during times of positive pricing. Note that 2050 sees lower curtailment compared to 2040, and therefore, there is less incentive to install larger heat pumps and storage causing a drop in capital costs.

It is clear from Figure 16 that there is substantially increasing value in installing seasonal storage in the future with increasing wind curtailment. A caveat is this analysis does not capture the higher prices which are likely in the future during periods where there is no curtailment of wind. Therefore, these results should be taken as an indication of the increasing value of electrified heating and STES.

Higher prices when there is no curtailment will further incentivise STES, as there will be a large price differential and more incentive to store larger volumes of heat during curtailment events.

The final part of this analysis is to consider network constraints and impose a 1MW grid import limit on the "curtailed wind discount 2050" scenario, see the last result on both Figure 15 and Figure 16. The network constraint reduces the ability of the system to take advantage of negative pricing, as seen with a reduction in the negative total system costs.

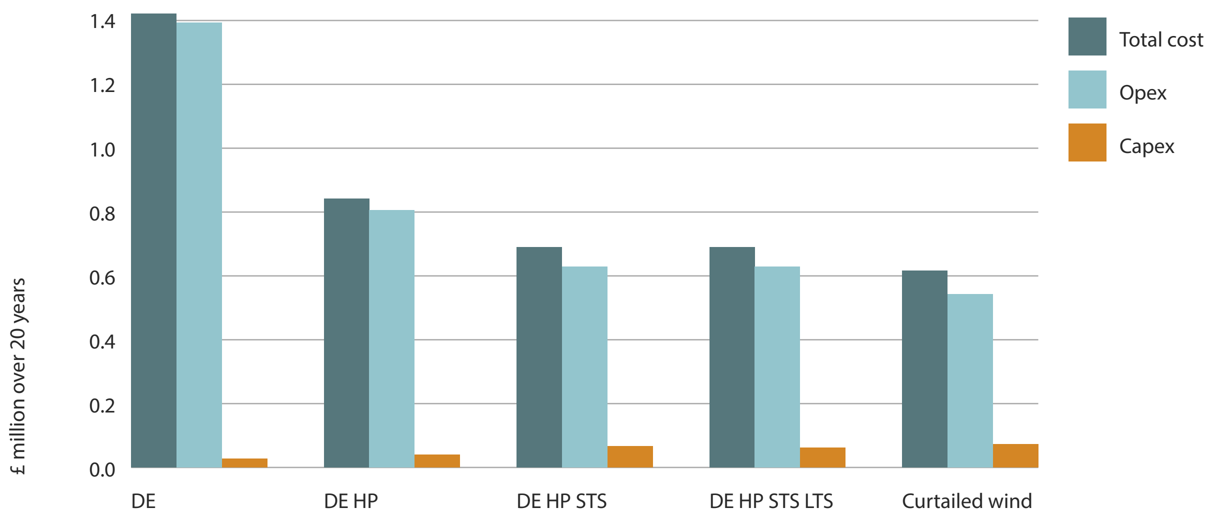

Figure 13: Total cost, opex, and capex of 5 scenarios. DE - Direct electric, DE_HP - Direct electric + heat pump, DE_HP_STS - Direct electric + heat pump + short-term storage, DE_HP_STS_LTS - Direct electric + heat pump + short term storage + long term (seasonal) storage, and CurtailedWind – all components of scenario 4 plus a curtailed wind discount. Opex – operational costs, Capex – capital costs.

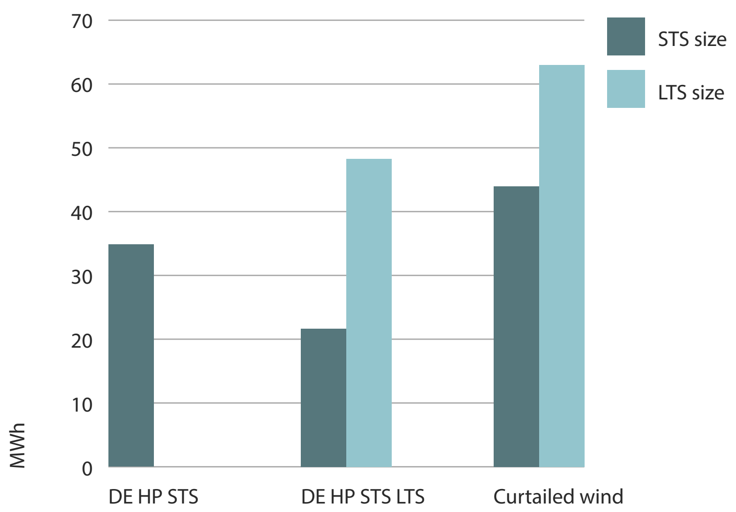

Figure 14: Sizing of short- and long-term thermal energy storage. DE_HP_STS: Direct electric + heat pump + short term storage, DE_HP_STS_LTS: Direct electric + heat pump + short term storage + long term storage, CurtailedWind – scenario 4 + curtailed wind discount. STS_size: Short term storage size and LTS_size: Long term (seasonal) storage size.

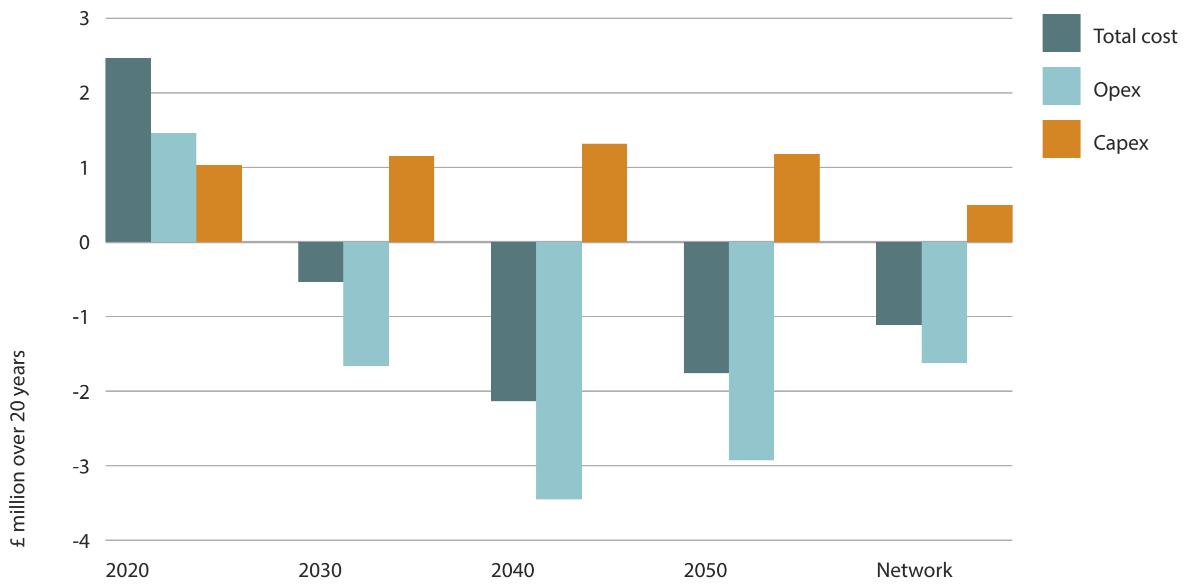

Figure 15: Total cost, opex, and capex for curtailed wind discount in modelled future years. Also includes Network which is a scenario with 1MW limit on electricity import. Opex: operational costs, Capex: capital costs.

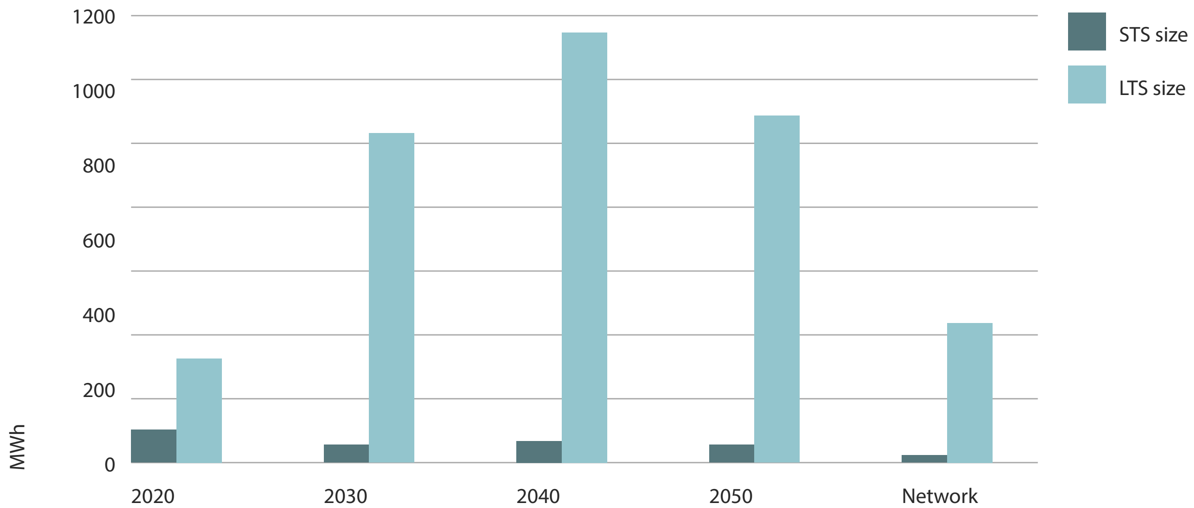

Figure 16: Thermal storage optimal sizes for scenarios with curtailed wind discount in modelled future years. STS_ size: short term thermal energy storage size, and LTS_size: long term (seasonal) thermal energy storage size.

In conclusion, based on electricity prices and wind curtailment events in 2019, the replacement of direct electric heaters with heat pumps and short-term thermal energy storage has the largest reduction in total system costs, while the benefits of STES are marginal. In the near future (2030) and beyond (2040, 2050) wind curtailment events will be more common, and STES provides higher value, with this analysis showing negative total system costs. However, these could be mitigated to a degree by higher non-curtailment event prices which are not included in this analysis. More detailed modelling is required to include more realistic total system costs for the future years modelled. Finally, network limitations will have impacts on the ability of these systems to respond to curtailment events.

5. Hydrogen

A. Description of the option

It will be essential to decarbonise transport fuels and heat to meet climate goals. In the UK, smaller hydrocarbon fuelled vehicles will be banned from 2030, and larger ones from 2035. Hydrogen has the potential to be used in a number of ways to support this – any one of which could be useful to Scottish Borders Council:

- As a vehicle (or railway engine, etc) fuel through a fuel cell. The fuel cell uses the reaction between hydrogen and oxygen to produce electricity, with the waste product being water (Cano, et al., 2018).
- As a vehicle fuel in a combustion engine. This replaces diesel or petrol in a similar type of engine (Eichlseder, Wallner, Freymann, & Ringler, 2003); it is possible in principle to convert an existing petrol engine to run on hydrogen (Page, 2021).
- As co-combustion in a diesel engine. Here hydrogen replaces up to 70% of the diesel fuel used – although less is currently standard – but does not replace it completely. This does allow the use of 100% diesel as a backup service provision (ULEMCo, 2022).
- In combustion for heating or industrial purposes, to replace natural gas (SGN, 2022).
- As an energy storage medium, where it can be produced using electricity and readily stored, then can be used to generate electricity (Scafidi, et al., 2021).

B. Case study

B.i Case study 1 – Scottish Borders Council vehicle fleet

B.i.a Purchase Costs of Hydrogen fuelled vehicles

SBC operates – either owned, leased or rented – a fleet of around 500 vehicles of various types. These are mostly fuelled with diesel, although some battery electric vans and cars are in service.

Broadly, hydrogen lends itself to larger and longer range vehicles due to its low weight, fast refuelling, and bulky fuel tank – as does diesel, albeit for different reasons. Therefore, we have a general expectation that ultimately hydrogen will replace diesel vehicles, and we assess this situation on that basis. However, the actual future out-turn is likely to be more complicated than we can readily foresee or assess at this time – this overlapping complexity is illustrated in Figure 17 below.

Figure 17 Overlapping future uses of renewable fuel types – image from Toyota Motor Corporation. FCEV is hydrogen Fuel Cell Electric Vehicle; BEV is Battery Electric Vehicle.

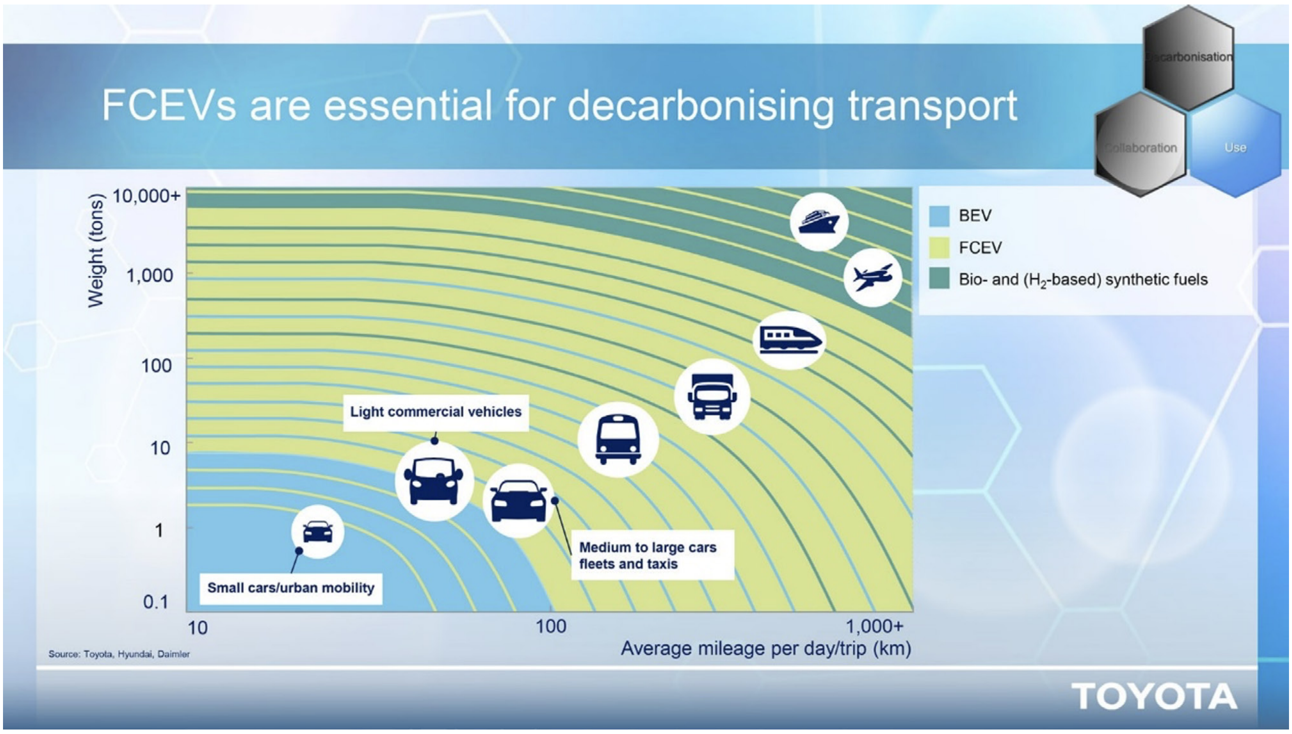

Figure 17: Overlapping future uses of renewable fuel types – image from Toyota Motor Corporation. FCEV is hydrogen Fuel Cell Electric Vehicle; BEV is Battery Electric Vehicle.

We assume here that fuel cell vehicles will be the system of choice to replace existing diesel vehicles, due to the significantly better fuel consumption and complete elimination of emissions in use compared to hydrogen combustion engines. However, vehicles with heavy duty onboard equipment may require a hydrogen internal combustion engine to operate hydraulics and respond to sudden changes in power demand, as developed by JCB (JCB, 2022). Fuel cell powered refuse collection vehicles are available (Hydrogen Central, 2022).

To consider the purchase cost of hydrogen vehicles, we consider the costs of hydrogen vehicles based on a selection of vehicle types, shown in Table 20 below.

Table 20: Comparative purchase costs of hydrogen and diesel fuelled vehicles.

Vehicle type	Make and model	Cost	Diesel equivalent considered	Diesel equivalent cost	Cost uplift
Family car	Toyota Mirai (Toyota, 2022)	£50,000	Peugeot 508 1.5 diesel	£32,000	56%
Refuse lorry	Unbranded (Stewart, 2021)	£368,000	TBC	TBC	TBC
Double decker bus	ADL (Long Branch, 2021)	£350,000	ADL	£230,000	52%

The average extra cost for a hydrogen fuel cell vehicle is approximately 54%, though over time and at large scale, that can be expected to decrease to zero, or even negative, due to the simpler construction of a fuel cell than an internal combustion engine (Pocard, 2022).

B.i.b Hydrogen requirement

The SBC report "Proposed Fleet Replacement Strategy 2022-2027" identifies a total of 1.9 million litres (Ml) of diesel fuel used per year (including around 500,000 litres of low duty red diesel, which is now unavailable).

On the assumption that future hydrogen road vehicles will use more efficient fuel cells rather than combustion, it is relatively straightforward to convert this amount into an equivalent quantity of hydrogen:

Energy content of diesel used = 1.9 Ml × 10.57kWh/litre (Engineering Toolbox, 2022) = 19.7 GWh

Useful energy at wheels = 19.7 GWh × 40% diesel drivetrain efficiency (Kobayashi, Plotkin, & Kahn Ribeiro, 2008) = 7.9 GWh

Energy content required from hydrogen = 7.9 GWh / 60% FCEV drivetrain efficiency (Dalyrmple, 2019) = 13.1 GWh

Quantity of hydrogen required = 13.1 GWh / 33.3 kWh/kg (based on LHV14) = 395,000 kg/year

= 1,520 kg/day (at 5 days/week).

= 1,083 kg/day (at 7 days/week).

This assumes that all current diesel powered vehicles will be replaced with hydrogen vehicles, as discussed above. However, if other factors will change this for SBC, then the hydrogen forecast can be reassessed – this will also require a more detailed breakdown of current fuel use by vehicle or vehicle type.

If the council wishes to facilitate use of hydrogen fuelling by the public or businesses, then clearly the total demand would increase.

To give some context, a small fuelling station in Scotland might sell 2 million litres of mixed petrol and diesel per year; a large one, such as a supermarket, around 11 million litres per year. These are equivalent to around 1,000 and 5,700 kg/day hydrogen (note that less hydrogen is required to replace petrol than diesel).

B.i.c Fuel source – the hydrogen hub and its capital costs

A hydrogen hub, or centralised production facility, could be constructed in the Scottish Borders area. Depending on the fleet operating strategy, a single refuelling site might be enough to support the fleet demand or an additional number of distributed refuelling points might be required.

14 The energy content of fuels can be measured in two ways: Lower Heating Value (LHV) and Higher Heating Value (HHV). For most hydrocarbon derived fuels the difference is below 10%, but for hydrogen the difference is about 20%. HHV assumes that the heat of vaporisation embedded in the water vapour produced can be recovered, such as in a condensing boiler. LHV excludes this, which would be more applicable in a road vehicle (Mazloomi & Gomes, 2012).

A production facility would be most likely to use electrolysis of water to produce the hydrogen. This requires a supply of electricity and water, and an electrolyser. It produces no harmful emissions – only oxygen, which has a commercial value itself or can safely be vented to the atmosphere. There are a number of potential international suppliers of electrolysers, and closer to home Aqualution in Duns aspires to commercialise a high efficiency electrolyser of their own design. The other currently viable source of hydrogen is through steam reformation of methane. That, however, requires natural gas as a feedstock and produces carbon dioxide as a waste product. While capturing the carbon dioxide and sequestering it is feasible, it is unlikely to be viable at a relatively small scale. Also at present it is an incomplete capture process meaning that some carbon dioxide would escape to the atmosphere. A number of other potential production methods are at the research and development stage.

The energy requirement for hydrogen production has two main components: electrolysis of water, and compression of the produced hydrogen gas. The electrolysis energy demand is found from the HHV energy content of the hydrogen (39.4 kWh/kg), divided by the electrolyser efficiency, which we take as 90%. Current installations are closer to 75%-80%, while installations in development are well over 90% as illustrated by (Hodges, et al., 2022). Compression requirements to 700 bar pressure are around 3.7 kWh/kg (Hua, et al., 2011). This leads to a total energy demand of 39.4/0.9 + 3.7 = 47.54 kWh/kg.

Water requirement is based on the molecular weights of water and hydrogen. One water molecule (H2O) weighs 18 Atomic Mass Units (AMU), and after electrolysis it yields one hydrogen molecule (H2) weighing 2 AMU. So the mass ratio of water input to hydrogen output is 9:1.

The resulting approximate quantities of water and electricity are as shown, with cost profiles, in Table 21.

Table 21: Inputs and costs to electrolysers – supply for SBC operated vehicles.

Hydrogen requirement (kg/day)	Water (kg/day)	Electricity input including compression (Assuming 90% electrolyser efficiency and 24-hour operation)	Capital cost estimate including electrolyser, compression, storage and dispensing equipment but excluding electricity source
1,080	9,750	2.1 MW	£2.2M
1,520	13,680	3.0 MW	£2.9M

Capital costs in Table 21 are derived from European estimates by (Tlili, et al., 2020) , combined with announced contract values for electrolysers (NEL ASA, 2020) and sense-checked with Logan Energy, hydrogen fuelling solution manufacturers in East Lothian.

A contribution to the energy requirement could come from curtailed energy from local wind farms, as discussed in Section IV above. As the energy requirement increases, however, it is most likely that a dedicated source of renewable electricity will also be required. A dedicated supply arrangement with an electricity source, or a wholly owned source, should be considerably cheaper than purchasing electricity through the national grid. The balancing effect of the grid would be less necessary due to the ability to store hydrogen in tanks.

If SBC wishes to facilitate the wider uptake of hydrogen vehicles outside the council, then a larger capacity hydrogen hub would be required. Additional capacity could be added on at a later date; this would be easier if the possibility is taken into consideration during the initial planning.

Ideally, the Hydrogen Hub would be located in an area close to good road transport links and to the main centres of operation. The map in Figure 18 below illustrates the key infrastructure and towns in the Scottish Borders area.

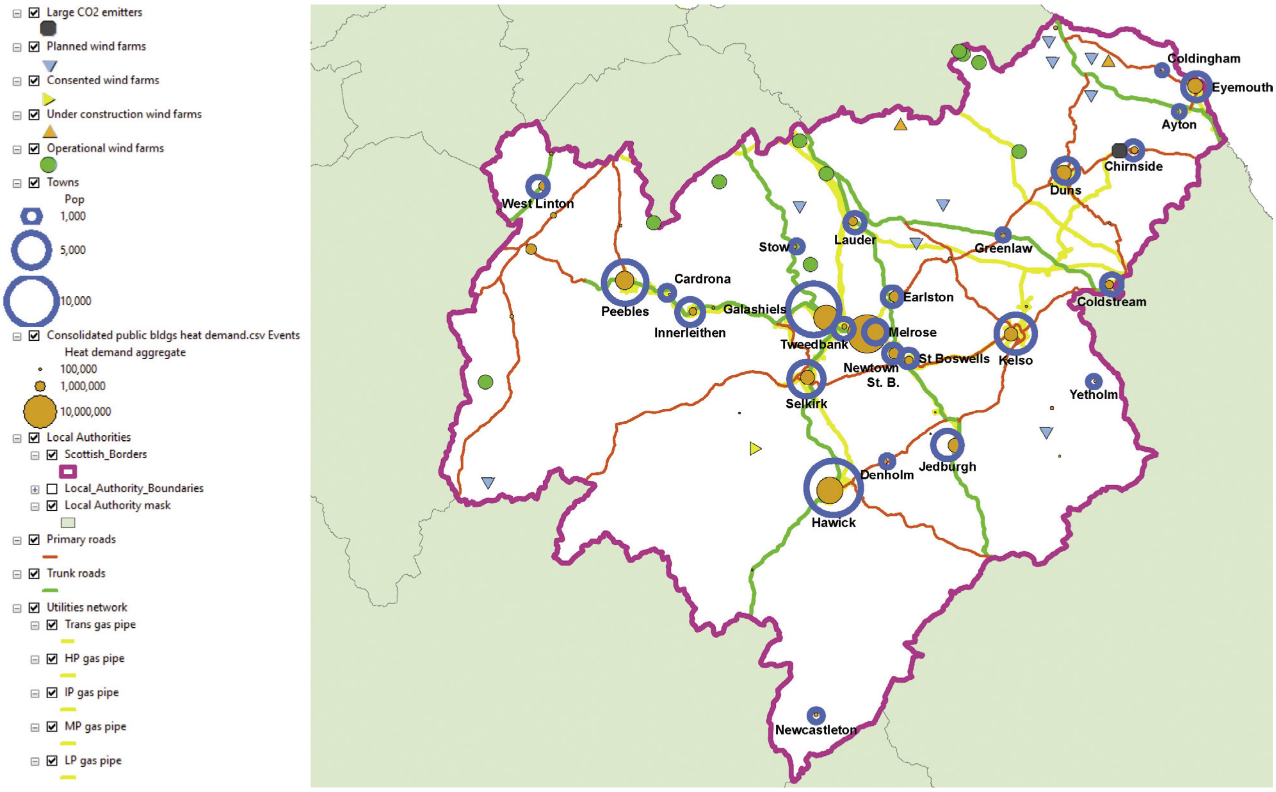

Figure 18: Plan of Scottish Borders Council Area, showing key infrastructure and demand elements.

SBC has previously indicated that suitable land might be available in Lauder, which as can be seen in Figure 18, is reasonably central with good access by road. It is also the location of a pressure reduction station in the natural gas network, which might be a useful injection site in the case that hydrogen is supplied into the gas network (see Section B.ii below). It is also close to a number of established windfarms to the north. However, it is still a distance of around 20km from the key central area around Galashiels, Selkirk and St Boswells, and depending on the number of vehicle movements needed for refuelling, this might become significant– it would be appropriate to conduct a fuller feasibility study into site options.

It would also be appropriate to take account of the operating strategy of SBC vehicles, in terms of whether or not they all return to the same base, or are there often enough to facilitate a central refuelling solution. If they don't, then consideration should be given to establishing one or more remote refuelling points. These could either produce their own hydrogen via on-site electrolysis, or they could be supplied from the hydrogen hub by pipeline or tanker or a combination.

B.i.d Unit costs

On the basis of the capital cost figures above in Table 21, and assuming a 25-year lifespan of the equipment, the unit cost will be approximately as set out in Table 22 below. This is based on a 1520 kg/day capacity installation.

Table 22: Breakdown of capital and operating costs.

Item	Unit cost	Hydrogen produced per unit at 80% capacity	Cost per kg Hydrogen
Capital installation as in Table 21	£2,900,000	11,100,000 kg	£0.26
Electricity for electrolysis and compression, if dedicated source constructed.	£0.04 per kWh (most recent strike price for offshore wind)	1/47 kg	£1.88
Water	£1 per m3 (base cost from Scottish Water)	111 kg	£0.01
Percentage uplift to allow for ancillary works, maintenance and other ongoing costs.			50%
Total unit cost estimate by weight			£3.24 / kg
By energy content at LHV (applicable to road transport)			£0.09 / kWh
Project Net Present Value (NPV), assuming 6% discount rate, ignoring land and tax.			£20.2M
NPV per unit produced			£1.82 / kg
NPV per unit energy content at LHV			£0.05/kWh

Clearly, among the quantifiable elements, the cost of electricity is dominant and water is insignificant; also the uplift for additional costs is approximate and would require detailed analysis for an accurate estimate.

The cheapest source of electricity at a larger scale is likely to be a wholly owned wind turbine, though a contribution from curtailed energy might be possible depending on availability and contract issues. However, if a large proportion of curtailed energy is to be used, that might lead to the need for a larger electrolyser and storage facilities to be able to deal with the increased intermittency of electricity supply.

At the scale of installation above, it is likely that a single turbine could provide sufficient electricity, although in that case consideration should be given to specifying a larger storage tank and electrolyser to improve resilience against periods of low wind. A backup connection to the national grid would also be an important provision, although as the energy cost crisis of 2022 is showing, excessive reliance on that could lead to high and fluctuating costs.

For context, a Toyota Mirai - a hydrogen powered large family car - has an official fuel consumption of 0.8 kg/100km, or 78 miles per kg (Toyota, 2022), with a range of 650km (400miles) and a refuelling time of a few minutes.
This leads to an approximate fuel cost of 2.6p per km or 4.1p per mile (not taking account of taxation or NPV discounting). This is considerably cheaper than any other fuel source at present, including mains supplied electricity for batteries, and could create the opportunity for SBC to create an income stream by selling hydrogen at a profit.

For the council's recent fuel consumption level of diesel at 1.9 million litres/year, the cost at current diesel prices of £1.95 per litre would be around £3.7 million per year (although SBC may be able to purchase bulk fuel more cheaply). Using hydrogen produced in the way described, the discounted annual equivalent cost of the 395,000 kg hydrogen required would be around £719,000 – a substantial saving of around £3,000,000 per year which would very quickly offset the initial capital costs.

B.i.e Greenhouse gas emissions

SBC vehicles typically use around 1.9 million litres per year of diesel. It is then simple to calculate the associated emissions, as burning 1 litre of diesel releases 2.68kg carbon dioxide (Engineering Toolbox, 2022). Therefore, the total fleet annual emissions are slightly over 5,000 tonnes CO2. The renewable hydrogen production system described here would result in zero emissions associated with hydrogen production (other than during construction of the facilities), so those 5,000 tonnes CO2 would be eliminated.

B.ii Case study 2 – natural gas replacement

B.ii.a Scale and cost

Another potential source of demand for hydrogen could be from replacing existing use of natural gas in domestic and commercial / industrial / public sector use. We can estimate the maximum extent of this as follows:

Domestic average annual demand for natural gas in SBC = 803 GWh (although note that winter demand is typically 4 times summer demand) (Scottish Government, 2022)

Industrial and commercial demand = 365 GWh (From private correspondence with SGN, available on request).

Total natural gas demand = 1168 GWh (equivalent to 80,000 tonnes at 14.6 kWh/kg)

Energy content of hydrogen at mean of LHV and HHV = 36.35 kWh/kg (Mazloomi & Gomes, 2012). The mean value of LHV and HHV is used slightly arbitrarily, because some processes are able to recover the heat of vaporisation of the resultant water vapour (such as condensing boilers) making the HHV applicable; some, such as cookers, are not.

Required quantity of hydrogen = 1168 GWh / 36.35 kWh/kg = 32,000 tonnes/year, or 83,000 kg/day.

This figure would only be reachable following full conversion of the gas network to run on hydrogen. At present, this is envisaged to take place from the late 2020s to early 2040s (SGN, 2022). In the meantime, however, it is technically feasible to blend 20% by volume of hydrogen with no modification of appliances or network as analysed by (Isaac, 2019). This requires a UK legislative change, but that is expected within one or two years. 20% by volume, however, represents around 6% by energy use (and a corresponding 6% reduction in emissions) due to the low density of hydrogen. Therefore the potential shorter term requirement for hydrogen in the gas network could be 32,000 × 6% = 1,930 tonnes per year or 5,280 kg/day average. The input and costs of this are shown in Table 23 below, calculated as described above in Section B.i.c and B.i.d:

Table 23: Inputs and costs to electrolysers – supply for replacement of grid supplied natural gas.				
Hydrogen requirement (kg/day)	**Water (kg/day)**	**Electricity input incl. compression. (Assuming 90% electrolyser efficiency and 24 hour operation)**	**Capital cost estimate incl electrolyser, compression, storage and dispensing equipment but excluding electricity source**	**Cost as NPV per kg of hydrogen, assuming electricity at £0.04/kWh, operating at 80% capacity**
5,280	47,520	10.4 MW	£7.9M	£1.75
We have not considered the requirements for 83,000 kg/day; this is a very large quantity and it seems at this stage more likely that it would be served by large offshore plant, distributing the hydrogen through a converted or new transmission grid.				

If developed to the full 20% by volume capacity, this would also require construction of interseasonal storage facilities, as winter demand is around four times summer demand.

B.ii.b Greenhouse gas emissions

Replacing 6% of the natural gas used with hydrogen – that is, 4,800 tonnes - would displace around 13,200 tonnes of carbon dioxide annually, at 2.75kg CO2 per kg natural gas combusted; replacing all the natural gas would displace 220,000 tonnes carbon dioxide per year.

6. Feasibility and recommendations

A. Feasibility study

In this section, the feasibility of all the options is analysed according to the required efforts and costs to deploy them. Their previously identified benefits are also summarised. Three categories of options, i.e., SLES, STES, and hydrogen options, are analysed respectively.

A.i Feasibility study for SLES options

HP rollout non-gas

Feasibility

- The HP rollout requires a large upfront investment. The upfront cost could be up to £8K per HP (Barnes & Bhagavathy, 2020).
- Local primary substations may need an upgrade to host the electrified heating. The upgrade cost could be prohibitively high. The highest estimated cost in 2030 could be £24.29K for Newcastleton and £30.26M for the overall Scottish Borders.

Benefits

- Replacing non-gas heating with HPs can significantly reduce the fuel poverty rate, especially for areas with a high non-gas rate. For Newcastleton, the fuel poverty rate reduces from 49.87% to 35.32%. For the Scottish Borders, the fuel poverty rate reduces from 29.3% to 21.8%.
- It can also lead to reduced GHG emissions. The GHG emissions of domestic heating could see a reduction at around 90% for Newcastleton and 30% for the Scottish Borders under the electricity carbon intensity in 2050.

HP rollout all

Feasibility

- As mentioned, HPs require a large upfront investment. Replacing the existing gas heating with HPs could lead to a higher financial burden and would not make use of the existing gas network.
- As all the heating options are electrified, the local primary substation may need more upgrades, leading to higher financial costs.

Benefits

- The fuel poverty rate can also be reduced. For the Scottish Borders, the fuel poverty rate reduces from 29.3% to 25.0%. The reduction is less than the "HP Rollout Non-gas" option, as HPs have higher annual heating bills than gas heating, based on the fuel price over year 2017-2019. However, this will depend on future electricity prices and on carbon tariffs which may in future be applied to gas, which could make natural gas heating more expensive than HPs.
- It can lead to the highest GHG emission reduction. With the higher penetration of renewables in the UK, the GHG emission reduction rate (for domestic heating) in this option could be more than 90% under the electricity carbon intensity in 2050.

However, other clean energy can also lead to the same environmental effect. Existing gas boilers are already able to accept a mixture of up to 20% hydrogen and natural gas. Hydrogen-ready boilers which can accept 100% hydrogen are under development. These are expected to reach a similar upfront cost to gas boilers, which is much less than that of HPs (Hydrogen-fired boiler, 2022). In future replacing gas heating with hydrogen may be more economic than replacing natural gas heating with HPs.

LFM of HPs

Feasibility

- ICT infrastructure for information exchange among the market operators and participants is required. The control function is needed for HPs such that they can be controlled remotely to provide the traded flexibility.
- A proper market mechanism design agreed upon by the DNO and other stakeholders is needed, along with an incentive mechanism for user engagement, e.g., a price for flexibility products or other financial rewards to encourage user participation.
- Real-time sensors for electricity demand and generation are required (e.g., smart meters, which should be available for DNO (Ofgem2020)).
- Forecasting tools for demand and renewable generation are needed. The DNO will require these to foresee upcoming events like congestion so that they have enough time to procure flexibility from the LFM.

Benefits

- Network upgrade cost reduction: For Newcastleton, if all HPs can engage in the LFM, there would be no need to upgrade the local primary substation up to 2030, corresponding to a cost reduction of £24.29K. For the overall Scottish Borders, the financial cost reduction in upgrading primary substations could be £1.38M (21.1% reduction rate) and £4.14M (13.7% reduction rate) in the two 2030 scenarios (corresponding to the minimum and maximum of the forecasted number of HPs in 2030 by SP DFES).
- Renewable hosting capacity improvement: LFM of HPs can improve the hosting capacity of primary substations for wind generation by 3.6% and 4.8% for the two 2030 scenarios in the Scottish Borders. It can also improve the hosting capacity for solar generation by 4.8% and 7.6% for the two 2030 scenarios.

EV rollout

Feasibility

- Investments in more charging stations are needed to incentivize EV adoption.
- Network upgrades to host the EV charging demand: In 2030, the upgrade cost for St. Boswell primary substation could be up to £534.44K and £10.24M for the overall Scottish Borders.
- The ban on the sale of new petrol and diesel vehicles from 2030 in the UK makes high EV uptake likely.

Benefits

- EV rollout can significantly reduce carbon emissions of the transportation sector. Compared to CVs, the GHG per mile is 75% less than that for CVs for now and could be close to 100% in 2050.

LFM of EVs

Feasibility

- ICT infrastructure for the information exchange is needed among the market operators and participants. A control function is also needed in the EV charging piles/stations for controlling EVs remotely to provide flexibility.
- A proper market mechanism design agreed upon by the DNO and other stakeholders is required, along with an incentive mechanism for user engagement, e.g., a price for flexibility products or other financial rewards to encourage user engagement. As EVs have higher flexibility than HPs, both DNO and EV owners can get more profits than the HP-based LFM. This could make them more motivated to organise and engage in this market.
- Real-time sensors are needed for electricity demand and generation, e.g., smart meters, which should be available for DNO (Ofgem, 2022).
- Forecasting tools are needed for demand and renewable generation. DNO requires them to foresee upcoming events like congestion so that they can have enough time to trade in the market.

Benefits

- Network upgrade cost reduction: For the St. Boswell primary substation, if all EVs can engage in the LFM, there would be no need to upgrade the local primary substation to host the EV demand up to 2050, corresponding to a saving of up to £534.44K in 2030 and £1890.03K in 2050.

For the overall Scottish Borders, the financial costs of upgrading primary substations to host the EVs could be reduced by more than 95% for all the scenarios in 2030 and 2050. The cost reduction is much more significant than the HP-based LFMs.

- Renewable hosting capacity improvement: A LFM of EVs can improve the hosting capacity of primary substations for wind generation by 13.1% and 22.6% (corresponding to 37.03 MW and 72.46 MW) for the two 2030 scenarios in the Scottish Borders. It can also improve the hosting capacity for solar generation by 11.1% and 22.1% (corresponding to 36.34 MW and 84.1 MW) for the two 2030 scenarios. Its improved renewable hosting capacity is more significant than the "LFM of HPs" case.

We classify all the SLES options based on their feasibility and benefits in Table 24. We anticipate the feasibility of LFM is not that low since LFM is now an emerging technology being adopted in the UK by DNOs (Piclo, 2022). The smart meter rollout could also meet the need for the real-time sensors and communication in organising LFMs (Ofgem, 2022). We therefore rank LFM of HPs as "Medium Feasibility". Considering LFM of EVs could lead to more benefits for both the system and the customers, we anticipate both sides could have high motivation to organise and engage in the LFM, so the LFM of EVs is seen to have "High Feasibility".

Table 24: Classification of SLES options based on their feasibility and benefits.

	Low benefits	Medium benefits	High benefits
Low Feasibility	HP Rollout All		
Medium Feasibility		LFM of HPs	
High Feasibility	EV Rollout	HP Rollout	LFM of EVs

A.ii Feasibility study for STES

Feasibility

- Tank thermal energy storage and pit thermal energy storage have high land requirements, but borehole and aquifer thermal energy storage have lower land requirements.
- Borehole thermal energy storage units require suitable geological conditions – drillable ground, favourable groundwater, high heat capacity, and thermal conductivity. They have high drilling costs, but low operating costs.
- Aquifer thermal energy storage units require suitable geological conditions – natural aquifer layer, confining low-permeability layers, no or low groundwater flow, suitable water chemistry. They have low drilling costs and low operating costs.
- A market mechanism is required to access the wind discount, for example, access to the balancing mechanism.

Benefits

- Total system costs for delivery of low-carbon heat are lower, relative to prevalent direct electric heating.
- Network operators benefit from relief from constraint payments to wind farms.
- Network upgrade costs are lower, offset by greater flexibility of operating heat pump/direct electric heating due to short-term and long-term thermal storage.

A.iii Feasibility study for hydrogen

Scottish Borders Council vehicle fleet

Feasibility

- Construct a centralised hydrogen production and fuelling centre – a 'Hydrogen Hub' with a capacity of 1520 kg/day, capital cost £2.9M and input demands of 3MW average electricity supply and 14 m3 water per day. This will provide enough hydrogen to refuel the council's fleet currently fuelled with diesel.

- Convert or purchase hydrogen fuelled vehicles to replace diesel powered vehicles, mostly on the planned replacement schedule. Initial cost is likely to be 50%-60% higher than diesel vehicles.
- Create, or contract for, a dedicated supply of renewable electricity to supply the Hydrogen Hub. This should lead to electricity costs of about 25% of current market rates for grid-supplied electricity. It will also eliminate any GHG associated with existing hydrocarbon fuelled power stations connected to the national grid.
- An extended option is to provide for the creation of a larger fuelling capacity to stimulate the demand for hydrogen fuel from public and businesses in the area.

Benefits

- GHG will be reduced by over 5000 tonnes per year.
- Fuel cost saving could potentially be as high as £3,000,000 per year, depending on tax and current price paid for diesel.

Natural gas replacement (This option would require development in association with SGN.)

Feasibility

- Construct additional production facilities at the Hydrogen Hub with a capacity of 5,280 kg/day, at a capital cost of around £8M, and supply this into the existing natural gas grid. When combined into the existing natural gas supply, this will be 20% by volume of the total, or about 6% of the energy. The existing network and appliances can accommodate this with no modification.
- Construct suitable inter-seasonal storage. This would be required to allow continuous production of hydrogen through the year, while providing for the considerably greater heat demand in winter. The options for this would require further assessment.
- An alternative would be an arrangement with SGN to accept surplus hydrogen from the vehicle fuelling facility in the event that supply exceeds demand and storage capacity.

Benefits

- Save 13,000 tonnes carbon dioxide per year, that is 6% of the emissions associated with natural gas combustion. This is obtained from a volume mix of 20% hydrogen and 80% natural gas. The lower density of hydrogen means that only 6% of natural gas, and associated emissions, are displaced this way. In practice, the volume flow rate would have to be increased to provide the same delivery of energy.

B. Recommendations

We provide recommendations for the three categories of decarbonisation options: SLES, STES, and hydrogen as below:

B.i Smart Local Energy System

Based on the analysis above, we have the following recommendations:

- Replacing non-gas heating with HPs can lead to high fuel poverty reduction and carbon emissions, especially for areas with high non-gas rate and is recommended there.

- Natural gas heating may need to be replaced to reach net-zero. Replacing the existing gas with HPs could be beneficial for the net-zero goal, but it could lead to higher heating bills and requires significant financial investments to install HPs and upgrade local networks. It is therefore worth investigating alternative clean energy sources like hydrogen in more detail which could replace gas heating.
- HP rollout may lead to prohibitively high financial costs in local network upgrades. Designing a LFM with HP participation can reduce the upgrade costs, and the LFM can also leverage the HPs' flexibility to improve the local renewable hosting capacity.

For areas with a high non-gas rate (indicating high potential electrified heating demand) and weak network infrastructure, organising a LFM with HP participation could be valuable.

- Organise a LFM for the EVs. EVs have higher flexibility compared to HPs. Organising a LFM for these EVs can significantly reduce the network upgrade costs for hosting the EV demand as well as greatly improving the room for local renewables. The flexibility of EVs means system operators could benefit and may be highly motivated to engage. .

B.ii Seasonal thermal energy storage

- It is recommended that more detailed analysis of the benefits of STES alongside a heat pump and direct electric heating be undertaken, particularly in the context of wind curtailment events which will increase in future.
- There needs to be investigation into a market mechanism to enable a discount for responding to wind curtailment events, e.g., participating in the balancing mechanism.

B.iii Hydrogen

- We recommend that detailed planning of a hydrogen hub with a capacity of 1,520 kg/day be progressed. This should be enough to supply the SBC vehicle fleet, with pre-planned options to expand it to serve the non-council demand as it develops. As the council fleet replacement is likely to take several years, there would be scope for such demand to develop within the initial capacity.

  * For context, this would be equivalent to a single medium-small sized fuelling station in Scotland supplying petrol & diesel.

- The Hydrogen Hub location should be identified as part of that detailed planning; an existing council depot at Lauder could be a viable solution with some advantages in terms of its location.
- The Hydrogen Hub should be powered using a dedicated and directly connected renewable electricity source. This will reduce costs substantially compared to grid sourced electricity, and will eliminate emissions associated with legacy hydrocarbon fuelled power stations still connected to the national grid. Curtailed generation might also make a useful contribution.
- The existing council diesel powered vehicle fleet should be replaced with hydrogen fuel cell powered vehicles, on the currently proposed timescale for fleet replacement.
- For natural gas replacement, discussions should be held with SGN with a view to either (1) creating additional hydrogen to supply into the network up to 5,280 kg/day average, or (2) accepting surplus hydrogen from the vehicle fuelling facilities. This last option might be valuable in the early stages, especially before demand has fully developed.

Appendix

A. Fuel poverty estimation

This section describes the methods for estimating the fuel poverty rate of an area. Based on the up-to-date definition of fuel poverty in Scotland, a household is considered in fuel poverty if i) the fuel cost is greater than 10% of their adjusted net income, and ii) the remaining income is insufficient to maintain an acceptable standard for living (Fuel Poverty (Targets, Definition and Strategy) (Scotland) Act, 2019). Due to the lack of data, we consider a household in fuel poverty based on the "10%" condition only.

From the definition, the most straightforward way to calculate the fuel poverty rate is to judge if a household is in fuel poverty one by one and then calculate the proportion of households in fuel poverty. However, this requires income and energy consumption data per household, which is generally not available due to privacy concerns. Therefore, our estimation procedures below will contain some assumptions.

Two elements are needed for fuel poverty rate estimation of a given area: adjusted net income data and annual fuel cost. The Scottish government published gross income statistics at Local Authority (LA) and sub-LA levels (like Newcastleton) (Scottish Government, 2018). We then estimate the adjusted net income data in a way such that the estimated fuel poverty rate of the Scottish Borders matches the existing data on (Scottish Government, 2019) (detailed estimation is given in Appendix A.i). The average annual fuel cost has been estimated in in Section II.B.i. Considering different fuel options lead to different costs and thus affect the probability of being in fuel poverty (e.g., a household heated by oil has a higher risk of being fuel-poor than the one heated by cheaper natural gas), for a given area, we first group the households based on their heating options. Then, we estimate the number of fuel-poor households for each group as the following:

a. Suppose each group has the same income distribution statistics (1st to 99th percentiles) as the whole area.
b. Suppose all the households in the group have the same annual fuel cost, and the fuel cost is the corresponding one in in Section II.B.i.
c. The percentage of fuel-poor households in this group is approximated as a-1, such that the ath adjusted net income percentile is the first one that is greater or equal than ten times the fuel cost.
d. Based on the total number of this group, we estimate the number of households in fuel poverty by multiplying the total number by a-1.

For each of the groups, we repeat the process above and get the corresponding number of fuel-poor households. The total estimated number of fuel-poor households is the summation of the number of fuel-poor households for all the groups. We finally get the estimated fuel poverty rate in the given area by division.

A.i Estimation of the adjusted net income distribution

This section describes how we estimate the adjusted net income distribution from the available gross income distribution. Based on the fuel poverty definition, the adjusted net income is the income after the deduction of housing costs, tax, and national insurance (Fuel Poverty (Targets, Definition and Strategy) (Scotland) Act, 2019). We suppose x% of the gross income is used for paying the housing cost, tax, and national insurance for all the income levels. Considering the choice of x% has a direct effect on the estimated fuel poverty rate, we keep adjusting the x such that our estimated fuel poverty rate matches the Scottish House Condition Survey 2019 data: "the fuel poverty rate in the Scottish Borders is 29% (Scottish Government, 2019)". Our estimated x is 30, meaning 30% of the gross income is used for paying the housing cost, tax, and national insurance.

Note that, our estimated "30%" is applied to all the income levels. In the real world, this number should vary for different income levels, e.g., people with higher income need to pay a higher proportion of tax in the UK. Therefore, the analysis in the report provides only an approximate evaluation. More accurate estimation would require lower-level information.

B. Peak demand calculation and the upgrade cost

B.i. Peak demand calculation

In this section, we describe the methodology for estimating peak demand for a local primary substation. The demand of a primary substation is the summation of the base demand (the current connected demand) and the heating/charging demand of HPs/EVs. SP DFES (SP Energy Networks, 2021) has provided the current maximum connected demand (i.e., the base demand in our case) for all the primary substations, we then multiply the shape[15] of the hourly UK network demand data (Wilson & Godfrey, n.d.) by the peak demand to get the hourly base demand data at the primary substations for one day. The hourly heating demand of all the HPs is simulated by OPEN (Morstyn, et al., 2020). Finally, the peak demand is then calculated as the maximum demand of the 24 hours on the coldest day (since the heat demand reaches the peak) in Newcastleton, where the temperature data comes from an online scientific-quality weather and energy data tool (Renewables.ninja, 2022).

B.ii Network upgrade cost

Data from DNO proposals has provided network upgrade costs (in M£) for installing several levels of additional capacity (in MW). For each of their estimated {cost, new capacity} pairs, we can get the upgrade costs per new capacity (unit cost) in £/MW. We then pick the average value of the unit costs for all the pairs, which is £236.9K/MW. Given these above, to estimate the upgrade cost of a primary substation, we first simulate its peak demand via the method in Appendix B.i. When the peak demand exceeds the capacity limit, the upgrade is triggered and we calculate the costs by multiplying the part of demand exceeding the capacity limit by the unit cost.

Note that, in our estimation, we only focus on the upgrade costs when the demand goes over the capacity limit. In the real world, even if the demand is within the capacity limit, it may be still necessary to upgrade the existing cables. However, this cost is much less than the cost of upgrading the primary substations, so we exclude this part in our analysis. Also, we do not consider voltage limits and reactive power compensation.

15 The shape means the normalised curve, i.e., the original curve is scaled such that the maximum is 1.

C. Renewable hosting capacity

This section describes the method for calculating the renewable hosting capacity of a primary substation. The renewable hosting capacity refers to the maximum renewable capacity that can be installed within the network capacity limit. Improving the hosting capacity reduces the network upgrades required to install more renewables. As the renewable generation can offset the demand locally, the network capacity limit is imposed on the absolute difference between the renewable generation and the network demand (i.e., net demand), which is different from the peak demand case where the capacity limit is imposed for demand only. The renewable generation and system demand is calculated as the following:

- We calculate the hourly renewable generation by multiplying the renewable capacity by the normalised hourly renewable generation curve. Here, "normalised" means that the data is scaled to have the maximum being 1. Renewable ninja provides both hourly wind and solar generation data under a given capacity setting. We divide the hourly renewable data by its capacity setting to get the normalised hourly generation data.
- The demand is also composed of the base demand and the HP/EV demand, which is calculated using the method in Appendix B.i.

Given the above, we calculate the renewable hosting capacity of a primary substation by finding the maximum renewable capacity such that the absolute differences between the hourly renewable generation and the demand over 24 hours of one day are all within the capacity limit. Considering that the renewable generation fluctuates significantly, to make our estimation more accurate we repeat the calculation for 14 days, where the middle of the 14 days is the one when the renewable generation reaches its maximum over one year. The chosen 14 days then represent the "worst period" over the year. In other words, the renewable generation over that period is the highest over the year and thus the network capacity limit is more likely to be violated. In our data, the maximum day for wind is the 347th, i.e., one day in December, and the maximum day for solar is the 119th, i.e., the end of April. Our final estimated renewable hosting capacity is the minimum of the 14 results.

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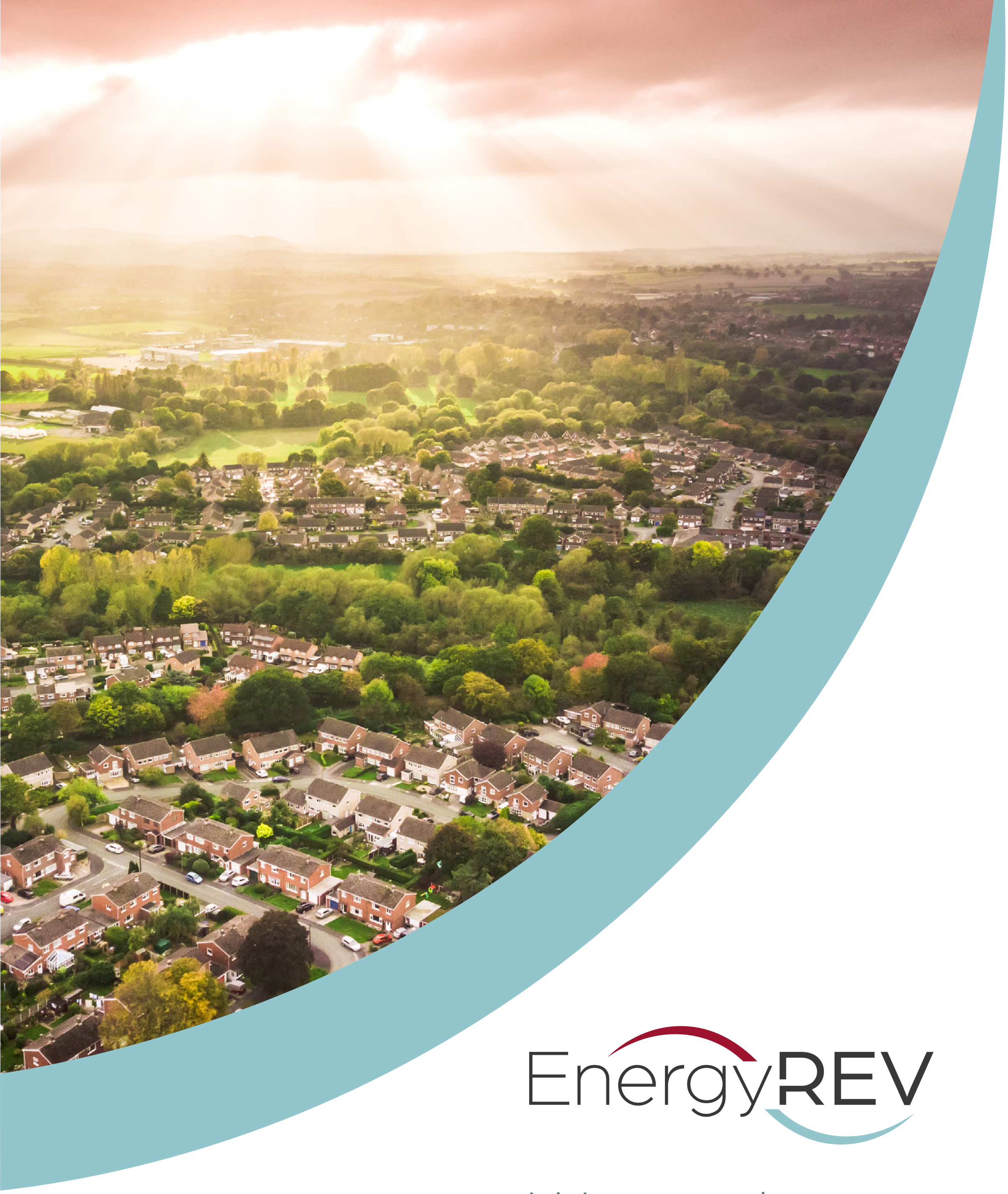

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