Programme Area: Energy Storage and Distribution

Project: 2050 Energy Infrastructure Outlook Multi Vector Integration Analysis

Title: Multi Vector Integration Study (Assessment of Local Cases)

Abstract:

This report presents the analysis of each of the Case Studies. In each case, detailed simulation of the proposed multi vector and counterfactual single vector energy system configurations has been undertaken. The technical simulations inform an analysis of the resource costs associated with the multi vector solution compared to the single vector counterfactual, in order to identify cases where the multi vector solution delivers a benefit. Alongside the analysis of economic benefits, the key engineering and operational challenges associated with the multi vector configuration are introduced. The work on engineering challenges and barriers, and a consideration of potential opportunities for innovation to overcome these barriers will continue in Work Package 5 of the study.

Context:

The project aims to improve the understanding of the opportunity for and implications of moving to more integrated multi vector energy networks in the future. Future energy systems could use infrastructure very differently to how they are employed today. Several individual energy vectors - electricity, gas and hydrogen - are capable of delivering multiple services and there are other services that can be met or delivered by more than one vector or network.

Multi Vector Integration Study

D3.1 – Assessment of Local Cases

for

The Energy Technologies Institute

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1 Executive Summary

This study considers how greater integration between energy vectors, principally electricity, gas, heat networks and hydrogen, could lead to a more flexible and resilient energy system in the future that is able to deliver carbon reduction objectives in a more cost-effective manner. Using a Case Study approach and considering a range of over-arching energy system evolutionary pathways, the study aims to identify circumstances where a multi vector approach to energy system development and operation will lead to a better outcome than evolution of today's largely independently operated energy networks. The study provides insights into identification of the system conditions and geographies that create opportunities for multi vector systems and the timescales over which these systems are relevant. These early insights will help to plan investment in key infrastructure that will be in place for the long term.

This report presents the analysis of each of the Case Studies. In each case, detailed simulation of the proposed multi vector and counterfactual single vector energy system configurations has been undertaken. The technical simulations inform an analysis of the resource costs associated with the multi vector solution compared to the single vector counterfactual, in order to identify cases where the multi vector solution delivers a benefit. Alongside the analysis of economic benefits, the key engineering and operational challenges associated with the multi vector configuration are introduced. The work on engineering challenges and barriers, and a consideration of potential opportunities for innovation to overcome these barriers will continue in Work Package 5 of the study.

A summary of the key findings of the local Case Study analysis is provided below:

Case 1: Retention of the gas network to meet peak heating loads in a future where heat decarbonisation is achieved by high electrification

Multi Vector Opportunity Investigated

Widespread electrification of heat, most likely using heat pumps, coupled to decarbonisation of grid electricity supply is a potential option for the decarbonisation of space and hot-water heating in buildings. However, a number of studies have indicated that the costs of reinforcing the electricity network, and increasing the capacity of the generating fleet in order to cope with the increase in peak loads associated with meeting thermal demands will be extremely high; the Smart Grid Forum estimated a cost of £20-50bn to reinforce the distribution networks in order to accommodate a potential 40 GW increase in peak load associated with high heat pump uptake (this estimate does not include the costs associated with increasing the capacity of the generation fleet).

The multi vector opportunity explored in this case is to retain the gas network to meet peak heating demands, while electric heating meets the baseload, e.g. through deployment of hybrid heat pumps. The alternative single vector configuration is use of demand management to mitigate the extent of peak demand increases on the electricity system, together with the necessary reinforcement of the electricity network.

Scope of Analysis

The modelling has been performed at the scale of a UK city – Newcastle has been selected – and includes consideration of the costs associated with reinforcement of the HV and LV tiers of the electricity network. Heat pump uptake is consistent with the BEIS high scenario used in the Smart Grid Forum work. Parallel Electrical load growth due to uptake of electric vehicles - following the BEIS Central scenario - is included.

Electricity wholesale prices are derived from ESME and PLEXOS models for a scenario of high electrification of heat (e.g. around 65% of domestic heat loads electrified by 2050). Gas and carbon prices are taken from BEIS projections.

The costs associated with operating the gas network at significantly reduced utilisation has also been considered in the analysis.

Main Conclusions

Unmanaged uptake of heat pumps, where these entirely replace gas boilers, necessitates grid reinforcement costing £4,000 per household that switches from gas to electric heating or more. While the peak loads that drive reinforcement occur only for a small fraction of the year, they tend to be clustered into consecutive days during winter cold spells, so building-scale hot-water tanks cannot store sufficient heat to avoid the imposition of large electric heating peak loads on the grid. This suggests it will be difficult to substantially electrify heat without significant grid reinforcement. Further, as heat pump uptake is clustered, rather than uniformly distributed across the city, even moderate heat pump uptake is associated with significant per household network-reinforcement costs.

Multi vector heat supply allows much of this grid reinforcement to be avoided without significantly undermining decarbonisation objectives –over 90% of thermal demand can be met by heat pumps while avoiding substation reinforcement. Increased running costs due to consumption of gas in the multi vector case are far outweighed by the saving in electrical grid reinforcement costs, even in a high carbon price scenario (at a £200/tonne carbon price an annual increase of £11 per household has been identified).

In the unmanaged single vector heat pump uptake scenario, the LV electrical network reinforcement costs dominate HV costs, and LV feeder upgrade costs dominate those of substation upgrades; multi vector heat supply where gas is used to avoid substation overload may still incur significant feeder upgrade costs. A more sophisticated control system, which monitors feeder loads and dispatches gas boilers to avoid overloading of individual cables, could increase the grid reinforcement saving; this analysis has identified a saving of £2,000 per household in the substation monitoring case, rising to more than £3,000 per household if feeder loads were managed, although the greater monitoring and control capability would come at a larger control system cost.

The main system saving of multi vector heat supply accrues to DNOs; central policy may be required to incentivise them to realise the value of the avoided reinforcement, and create a platform for information sharing with required parties, most obviously; gas distributors, aggregators and manufacturers/installers of heat pumps.

The operational impacts of the multi vector configuration on the gas network are expected to be manageable – potential ramp-rate and pressure drop issues associated with highly correlated firing of gas heating plant could either be managed as part of the multi vector control system or, alternatively, by introduction of storage on MP networks (this has not been costed in this analysis). The required revenue of gas network operators is not expected to fall proportionally with reduced throughput, due to depreciation and fixed opex, hence significant increases in the gas price per unit are likely as gas demand drops (we estimate that at 75% reduction in gas consumption results in a three-fold increase in gas network charges on a per volume basis, or around a 40% increase in the total gas price, assuming other components remain the same). Changes to the gas charging structure will be required to ensure the network costs are fairly distributed across gas users. Pricing incentives may also be required to ensure that multi vector customers do not use gas at times outside of the periods of electricity system stress, as this could result in significant additional CO_2 emissions.

Case 2: Gas-fired CHP and electric heat pumps supplying heat networks

Multi Vector Opportunity Investigated

In this Case Study we consider a multi vector arrangement in which a gas-fired CHP works in tandem with an electrically powered heat pump to provide heat to a district heating system. The hybrid multi vector mode, in which the gas CHP generates electricity to power the heat pump, with both contributing to thermal demands, is equivalent to a gas engine heat pump with a similar overall efficiency. (A hybrid multi vector system, in which a gas CHP generates heat and electricity to run a ground or water source heat pump, will have an overall system CoP of between 1.3 and 1.6 and may offer a cost-effective and environmentally beneficial means of integrating cogeneration plant into the energy system - a gas-only CHP scheme has a thermal CoP of around 55%, while a heat pump powered by a CCGT will have a thermal CoP of around 2, but higher capital and (due to the network usage premium) electrical generation costs).

The multi vector system will also have the potential to alleviate stresses within the electricity system - through the import of oversupply, or the export of CHP cogeneration - and to provide ancillary services. Depending on the power purchase arrangements, the multi vector system may be able to respond to price signals by varying the dispatch mode; at very high electricity prices the heat pump may be turned down and the CHP electricity exported to the grid, while at very low (or negative) electricity prices, the heat pump may run on grid electricity alone.

The case aims to identify under what future energy system scenarios a multi vector solution lowers the supply cost of heat; assessing the potential for multi vector energy centres to:

- make cheap low-carbon heat
- lower exposure to gas and electrical price movement.

The multi vector system configuration has been compared to two single vector alternatives:

a. a gas CHP based district heating system and
b. a heat pump based system.

Note that in the single and multi vector cases gas boilers are included to meet peak demand.

Main Conclusions

The analysis finds that for a district heating scheme developer selecting a low carbon thermal plant option today, the multi vector configuration is the lowest cost heat supply option for a range of medium to long-term future energy system pathways, with the majority of savings due to the lower capital cost of CHP engines compared to heat pumps per MWth of output.

As the multi vector operation inherently hedges against fuel price movements, multi vector DH schemes are not exposed to significant price risk and, indeed, the benefit of the multi vector scheme increases as a function of electricity price volatility.

However, where carbon or electrical export prices are very high, other options may compete with multi vector schemes. Specifically, under very high carbon prices heat pumps outperform multi vector systems, and where cogenerating export price are high CHP-only schemes do better; this includes scenarios where cogeneration displaces local demand, and offsets electrical import.

For a multi vector DH scheme, hybrid operation - in which CHP cogeneration is used to power a heat pump - is the lowest cost heat supply option for over 90% of the year at carbon prices below £90/tonne. Above this price, the scheme operates increasing in heat pump only mode (drawing power from the grid). As prices this high are not seen in any of the scenarios considered here before 2030, multi vector operation is likely to be a sound heat supply option for DH schemes built in the next 10 years. Depending on future carbon prices and environmental policy, it may be worth decommissioning the CHP engine and replacing it with an additional heat pump at the end of its 15-25 year lifetime.

While it has higher running costs and lower emissions savings than a heat pump scheme, the multi vector configuration also provides the cheapest means of decarbonisation compared to gas heat supply.

Such configurations include, for example, the connection of a CHP engine which supplies a heat network to one or more large heat pumps in nearby facilities through private wire, indeed the operator of a given CHP engine can lower their overall cost of heat supply through the purchase of a large heat pump, even given the substantial investment required. The case study analysis is applicable to all such multi vector configurations, providing all plant is connected to sufficient thermal demand, and that the capital and operating costs of the private wire are included.

Case 3: Plug-in hybrid electric vehicles switching between electric and liquid fuel running modes at times of tight electricity supply margins

Multi Vector Opportunity Investigated

Widespread adoption of electric vehicles coupled to decarbonisation of the electricity grid is a pathway to decarbonisation of road transport (cars and vans). Most forecasts of the uptake of electric vehicles envisage a significant role for plug-in hybrid vehicles that have both an electric motor and petrol or diesel combustion engine. Element Energy modelling using ECCo, for example, produced scenarios that include 8 million plug-in hybrid cars and a further 1 million plug-in hybrid vans by 2050.

As the electricity generating fleet transitions toward increasing levels of renewable energy generation, much of it in the form of offshore wind, there is a potential vulnerability to extended periods of very low wind speeds, in terms of capacity margins. The installation of fossil-fuelled back-up generating capacity, for example in the form of low load factor gas or diesel engines, is one potential response to this risk. This Case Study explores whether shifting the fleet of plug-in hybrid vehicles off the electricity system onto the liquid fuel network is an alternative solution to these prolonged low wind speed events.

The Case Study analysis considers the system level benefit of moving the energy demands of 8m PiV users off the electricity network during a two-week period of low wind speeds in January 2050. We note that given the expected increasing sophistication of electric vehicle charging, this multi vector solution is only likely to be beneficial during prolonged periods of electricity system constraint, where single vector demand management (i.e. time-shifting the electric vehicle demand) and electricity storage are insufficient to overcome the constraint.

Main Conclusions

The case analysis has found that the opportunity for fuel-switching of hybrid electric vehicles to liquid fuels at times of electricity system stress is limited. The modelling has shown that the spikes in electricity price under a high grid decarbonisation scenario in 2050 are for the most part too low to justify a switch to liquid fuels and, when sufficiently high price spikes do occur, they tend to be of short duration such that a single vector load management strategy would be an effective means of shifting EV load away from the constrained period.

The analysis uses an oil price scaled to the BEIS gas price projection; the oil to gas price ratio would need to shift considerably from current levels to alter this conclusion, however we note that oil prices are already at a historically low level. Variations in the carbon price also do not materially affect the findings, as liquid fuel for transport and fossil-fuelled generating plant are impacted by the levy in the same way.

The analysis has not included a quantitative analysis of the impact on cost of liquid fuels of the reduction of demand as transport is increasingly electrified. The ETI Consumers Vehicle Energy Integration (CVEI) project has found that around 6,000 petrol stations are likely to be required to serve the UK population to 2050. As throughput per station drops, the fixed operating costs of the fuel distribution and retail networks will contribute a larger component to the pump price per litre. This is likely to further squeeze the marginal opportunity for fuel-switching to provide a system benefit.

Case 4: RES electricity generation to gas (hydrogen or methane) for injection into the gas system

Multi Vector Opportunity Analysed

This Case Study investigates the potential for electrolysis - converting power to hydrogen – to mitigate the curtailment of renewable electricity generation, by examining 2050 scenarios in which the installed capacity of UK of wind generation is very high – around 90GW. Two variants of this multi vector solution have been assessed, one in which hydrogen is injected into the gas transmission system, subject to allowable concentration limits, and an alternative in which hydrogen is fed into a methanation process to produce SNG, which can be injected into the gas grid without concentration limitations. The system benefit of the multi vector configurations is then compared to the benefit of using economically sensible single vector counterfactual solutions – grid reinforcement and electrical energy storage.

Main Conclusions

The analysis has shown that power-to-hydrogen is not an economically competitive solution to system level renewable oversupply even at the levels forecast in the 2050 scenarios studied; rather it was found that selective reinforcement of the local transmission network - the single vector counterfactual - is likely to deliver greater net benefit to the system, while reducing the levels of curtailment.

Despite the amount of renewable generation (up to 94GW) on the system, the duration curve of capacity curtailment leads to low annual capacity factors which, combined with the high LCOE of hydrogen generation driven by the high electrolysis capex and efficiency losses, make the investment in electrolysis less appealing than its single vector counterfactual. The alternative multi vector case of methanation (Power-to-SNG), seems to be even less economically attractive, due to its higher capital and operational fixed costs and further efficiency loss.

The only case where methanation brings significant system benefit at a price competitive with the single vector alternatives is where it leads to net carbon reduction by removing CO_2 that would otherwise be emitted in the atmosphere.

Reduction of investment costs and further efficiency improvements could help make electrolysis an economic system level option for dealing with renewables curtailment.

The economic viability of methanation as a system-level solution to renewables oversupply would require significant reduction of cost and improvement of efficiency.

This Case Study adopted the system-level perspective, assessing the advantage of power-to-gas over traditional solutions for the reduction of renewable energy curtailment for the whole energy system.

However, from a private ownership perspective, building electrolysers may be a viable option, especially in regions with significant levels of renewable curtailment. Regulatory drivers (such as feed-in tariffs for renewable hydrogen) would further improve the attractiveness of power-to-gas using renewable surplus to generate hydrogen.

Case 5: Grid electrolysis to produce hydrogen for a hydrogen distribution system

Multi Vector Opportunity Analysed

The potential for hydrogen to become a main vector for the provision of heating and cooking energy in the UK, by replacing natural gas in gas distribution networks, is attracting significant attention - not least through the H21 Leeds City Gate project, which has assessed the implications of such a transition in the city of Leeds.

The H21 Leeds study has focussed on steam methane reformation (SMR) with carbon capture and storage (CCS) as the principal means of generating hydrogen. The ability to store hydrogen in salt caverns has been assumed as a means of managing the significant inter-seasonal and intra-day demand fluctuations - especially given the low ramp rate of the primary H_2 production technology.

In this Case Study a multi vector configuration has been assessed in which hydrogen is supplied by the combined operation of SMR with CCS and electrolysis powered using grid electricity; electrolysis supports the matching of intra-day demand as it is more flexible than SMR due to its faster ramping rates and may therefore partially replace the requirement for hydrogen storage.

The Case Study examines the benefit of this multi vector configuration as a function of total investment and operational cost compared to the single vector approach (i.e. SMR/CCS as the only hydrogen production route).

The analysis is based on heating demand for a city of the scale of Leeds - 6.4 TWh annually - and uses 2050 projections for the hourly electricity price profile and shadow price for natural gas (derived using ESME 2050 Scenario 3 and PLEXOS modelling). In the base case the average electricity price is £47/MWh, while natural gas is costed at its ESME shadow price at £28/MWh. Sensitivities to electrolyser capex, electricity prices and maximum dispatch rates of hydrogen storage have been assessed.

Main Conclusions

Under the base case assumptions, the modelling has shown that the single vector solution of SMR and hydrogen storage is preferred to the multi vector configuration, i.e. the model determines that building electrolysis would not provide a net cost benefit.

The multi vector solution begins to deliver a benefit if the electricity prices drop significantly below the 2050 forecast used in the base case – the more the average electricity price is reduced, the larger the capacity of electrolyser built in the system and the greater the cost saving. At an average 2050 electricity price of £32/MWh (a £15/MWh reduction on the base case), the multi vector solution delivers a cost benefit of around 3% compared to the single vector case. It can also be observed that when electrolysis is built in the system, the need for SMR capacity and the volume and rating (deliverability) of hydrogen storage are reduced.

Therefore, electrolysis competes in demand matching not only with SMR but also with storage, since electrolysis - being more flexible than SMR with faster ramping rates - can match intra-day demand swings, a function which would otherwise be provided mainly by storage.

Lower deliverability of hydrogen storage, i.e. a longer discharge time or volume to power ratio, also favours greater electrolyser capacity being built in the multi vector solution; as the discharge time is increased, larger levels of electrolysis are built to replace diurnal storage, which would come at a greater cost. This suggests that there may be scope for electrolysers to provide some of the required flexibility if access to the appropriate geology for hydrogen storage is limited, with resulting higher costs or lower deliverability.

Case 6: Renewable Electricity Connection Constraint Mitigated by Domestic Thermal Demand

Multi Vector Opportunity Analysed

Many areas of the UK's electricity network have become congested, leading to the imposition of limits on the connection of further renewable generation capacity, such as PV and onshore wind. Non-firm connection offers are becoming increasingly common in these areas, which can result in significant curtailment of export to the electricity network at times of local network constraint.

In this Case Study we investigate the potential for aggregated local domestic electric heating demand to match renewable electricity generation and reduce curtailment due to network constraints; two variants of this Case Study have been assessed:

a. A wind farm subject to network constraints and a nearby district heating system which is supplied primarily by a grid-connected electric heat pump - on a different HV electricity network to the constrained wind farm - and thermal storage. In the multi vector scenario, these are coupled together via an interconnector cable, which enables electricity generated by the wind farm that would otherwise have been curtailed to supply the heat pump.

b. Households connected to the same network as the constrained wind farm (i.e. on the same side of the network constraint) use electric storage heaters or boilers and hot water tanks as a distributed energy store; their thermal demand is managed to balance the output of the wind farm.

In each of these cases we determine whether multi vector configuration delivers a benefit over the single vector options of grid reinforcement and/or curtailment, and continued supply of thermal demands by the counterfactual system. In the former case, multi vector benefit depends on the cost of the interconnecting cable, which scales with the distance of the heat pump from the wind farm; we therefore calculate the benefit before accounting for the cable costs in order to identify a limit on this distance.

Main Conclusions

a. Wind Farm Linked to A Nearby District Heating System via an Interconnector

At the scale of wind farm assessed in the base case (15MW), curtailment was found to be a more cost-effective solution than investing in a higher rating transformer to overcome the grid constraint. For larger wind farms experiencing higher levels of curtailment, reinforcing the transformer becomes a sensible solution.

The benefit that the multi vector configuration brings is that the district heating system can utilise the excess of electricity for the supply of heat, reducing reinforcement and at the same time allowing the system to avoid the costs incurred from network losses when electricity is instead imported from the transmission system. The multi vector benefit was found to increase with the size of wind farm, i.e., with the level of energy curtailed, by being able to supply more energy to the heat pump offsetting the imported electricity and thus avoiding more network loss costs. However, at the sizes of wind farms tested, the multi vector benefit only outweighs the cost of the interconnecting cable for distances of around 1km.

b. Renewable Generation balanced by Demand Managed Storage Heaters – (SETS)

Smart Electric Thermal Storage (SETS) can unlock grid areas for renewables, particularly where generation is correlated with heat demand (for wind and hydro plant), though the benefit is lower for solar PV.

The ability to demand manage local domestic thermal loads is worth between £30 and £50 per household per year, commensurate with the new, commercial scale control system and telemetry costs of around £20 per device per year.

However, the control and monitoring retrofit costs associated with managing the existing 12-15GW of electric space heaters may be several times higher than this figure. Smart Electric Thermal Storage may therefore be a community specific, rather than system level, solution for unlocking renewable generation on constrained grids.

One possible model for scaling this solution up involves the inclusion - at no additional user cost – of immersion heating elements in new gas and oil boilers, allowing users to switch from fossil fuel to electric heating when electricity prices are low, and giving aggregators a large source of flexible electric demand; the viability of this model depends on aggregators creating sufficient value to cover the costs of the element and the control infrastructure and platform.

Case 7: EfW Flexing Between Producing Electricity and Gas for Grid Injection

Multi Vector Opportunity Analysed

Bio-gas and syngas can be produced by anaerobic digestion and gasification (respectively) of biodegradable waste material. These gases can be burned to generate electricity (and heat) in a gas engine, but also have the potential to be processed further to produce biomethane or bio-SNG of a quality that allows injection into the gas grid. In this Case Study we consider whether there is a benefit in providing the capacity to flex output between generating electricity and producing biomethane / bio-SNG in response to price signals, given the capex and opex associated with the additional processing steps.

The single vector configuration is a single delivery system, either generation of electricity in a CHP plant or injection of gas into the gas grid. For both the AD and waste gasification cases, we consider the benefit of adding the multi vector capability to each of these single vector configurations.

In the multi vector configuration, the plants can flex their output responding to price signals as follows:

a) The AD plant produces biogas which can be injected into a biogas CHP to produce electricity and heat. Alternatively, it can be fed into a clean-up and upgrading plant and subsequently into a grid entry unit - ensuring that the quality of biomethane is acceptable for grid injection.
b) The waste gasification plant produces syngas which is then post-processed (for the removal of contaminants, CO_2 etc.), to be converted to bio-SNG that can substitute for natural gas. At that point, it can either power a standard natural gas CHP or pass through a gas grid injection unit for further processing and quality analysis for grid injection.

For each pre-existing single vector configuration (either CHP or gas grid injection), the system will need to be equipped with additional technology to enable multi vector operation. We assess the conditions under which the ability to respond to relative electricity and gas price signals justifies the additional investment in this plant. In particular, the impact of the volatility in electricity and gas prices for varying levels of average gas and electricity price has been assessed, and the impact of varying degrees of correlation between electricity and gas price is also explored.

Main Conclusions

This analysis suggests there are price projections under which an existing single vector facility might build the plant required to flex between electricity and gas output. It is however only rational to build the plant required for this option under a very narrow range of future system prices at the outset – it is more likely that one route will be initially preferable, but that over time relative prices may shift to justify the investment in additional plant.

Given that the gas and electricity cost drivers may become increasingly uncoupled, and that their relative prices vary substantially over time – both in the short (volatility) and longer term (more structural shifts) –there may be value in reducing barriers to allowing biogas/biomethane projects to deliver both electricity and gas; such barriers are discussed in the accompanying report, *Barriers to Multi Vector Energy Supply.*

2 Introduction

Traditionally energy transmission and distribution networks have largely been considered as separate systems to be designed and operated independently, and subject to independent regulatory and market arrangements.

An alternative, multi vector, approach considers greater integration between energy networks, which enables synergies between different energy vectors to be exploited. To an extent these interactions already exist, through technologies such as combined heat and power, although they remain relatively niche. These interactions could, however, be increased significantly through greater uptake of technologies such as micro-CHP, hybrid heat pumps, power to gas via electrolysis, the integration of electricity with district heating networks through electric boilers or large-scale heat pumps, plug-in electric hybrid vehicles and so on. These ‘coupling’ technologies can enable greater coordination between networks, and thereby deliver benefits such as:

- Greater integration of intermittent renewable generation.
- Relief of peak loads on the electricity network, which strongly drive investment.
- Increased resilience and security of supply.
- Improved overall efficiency of the system, with resulting reduction of carbon emissions.

There are however significant challenges to achieving greater integration of the energy system, and greater coordination between the various networks:

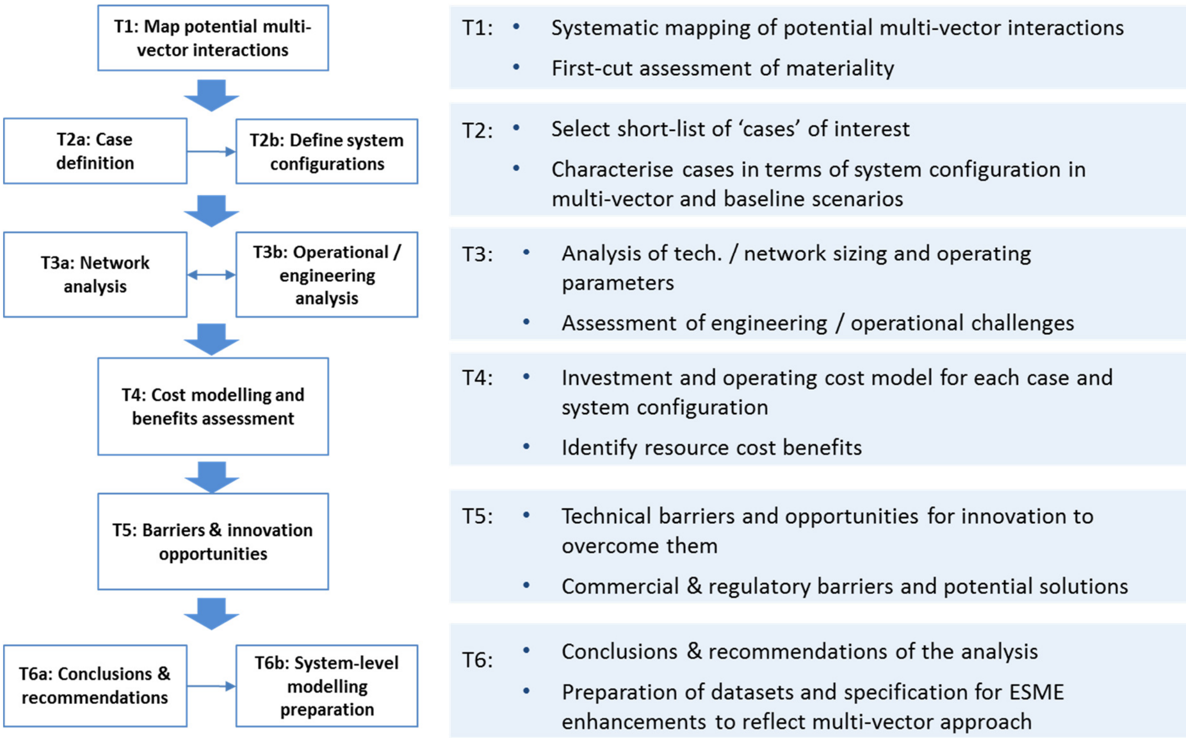
- Commercial and regulatory frameworks for multi vector energy supply do not exist.
- Optimal coordination of the planning and operation of multi vector systems is untried and may be difficult to achieve, both technically and commercially.
- Multi vector operation may result in underutilised network capacity which would affect existing business models; it is also not clear how new networks or control systems would be financed.
- Current sizing standards for electrical networks require sufficient capacity to meet the sum of individual peak demands; this conservative approach would lead to significant upgrade costs as heat and transport are electrified, and therefore preclude many of the benefits of an integrated, more flexible, energy system. These standards may become less stringent however, as demand side response becomes a significant network management tool.

This study seeks to identify the benefits that could be captured through closer integration of energy vectors and to understand the operational and engineering challenges involved in the transition to a more integrated system.

We have taken a Case Study approach to this task; each Case Study examines a potential constraint in the future energy system, and explores the potential for a multi vector system configuration to alleviate that constraint relative to a counterfactual ‘single vector’ approach based on less connected networks. The Case Studies consider issues such as local network constraints, falling generation margins, supply and demand imbalance and renewables intermittency, and solutions involving integration between electricity, gas, hydrogen, district heat and liquid fuel supply networks.

2.1 Approach to the study and purpose of this report

The overall approach to the study is summarised in the diagram below.



This report describes the work undertaken in Task 3 of the project, which includes:

- Technical analysis and economic modelling of the cases
- Discussion of the particular engineering and operational hurdles that will need to be overcome to shift to the multi vector system configuration.

This report includes:

- A detailed definition of each Case Study, including all major input assumptions.
- An overview of the methodologies and analytical tools applied in the analyses.
- Analysis of each Case Study in single vector and multi vector configurations, including quantification of relevant capacity requirements and operational parameters of each of the networks involved.
- Analysis of the cost implications of building and running the relevant networks in single and multi vector configurations and the associated costs and benefits of the multi vector system.
- An assessment of the operational and engineering implications of making the transition to operation of networks in the multi vector configurations[1].
- An assessment of the key findings of each Case Study and their implications for policy and regulatory bodies.

[1] The analysis of operational and engineering implications presented here will be further developed in Work Package 5.

2.2 Short-list of Case Studies

In Tasks 1 and 2, Case Studies were identified and then defined in detail. Following a comprehensive mapping of system constraints and potential multi vector solutions, a filtering exercise was undertaken, supported by the project steering committee, to arrive at a short-list of multi vector integration case studies of greatest interest. The filtering was based on a number of criteria, including:

- The **extent** to which the interaction solves an energy system issue or constraint
- **Materiality** of the issue
- Providing a good **spread of scale and position** in the energy system across the cases
- **Timescale** on which the Case Study is likely to become relevant
- The **existing body of work** done on the topic

On the basis of this filtering process, the following short-list of cases was selected for detailed analysis:

1. Domestic scale heat pumps and peak gas boilers.
2. Gas CHP and Heat Pumps supplying district heating and individual building heating loads.
3. Hybrid electric vehicles switching energy demand from electricity to petrol or diesel.
4. Power to Gas - RES to H_2/RES to CH_4
5. Grid electricity to H_2 for a hydrogen network
6. (a) RES to DH and (b) Smart Electric Thermal Storage (SETS)
7. Anaerobic Digestion/Gasification to CHP or Grid injection

2.3 Case Study Definition

Each of the Case Studies considers a locus within the energy system – a system level or a geographical area, and a set of associated energy demands – where multi vector operation may deliver benefits compared to a counterfactual, less integrated, configuration. The Case Study models do not represent the whole energy system, and for each a boundary is defined that encompasses those elements of the energy system that vary dynamically, and excludes those variables that are considered exogenously.

The following common features of each Case Study are identified:

Context and Setting

A qualitative description of the Case Study and identification of the involved users, system levels and /or geographic location considered, such as a town, or the energy demand of all hybrid cars.

Model boundary

The model boundary defines the variables and sub-systems that are optimised over. Further features of the energy system outside the model boundary, such as commodity prices, the interaction of energy supply and demand and infrastructure availability may be relevant to the Case Study but do not react dynamically within the model.

Exogenous Variables of Interest

For a given Case Study, the effect on multi vector value of specific variables exogenous to the model may also be investigated, in order to determine the scenarios under which the multi vector solution is particularly powerful, or marginal. A Case Study may compare several multi vector and single vector configurations for a variety of assumptions regarding key exogenous parameters, such as EV uptake or the volatility of electricity prices.

Global and system data

System level data, such as gas and electricity price series defined for certain ESME scenarios or carbon price trajectories, have as far as possible has been used consistently across the cases. Some of these variables will be exogenous, some endogenous, to each Case Study.

Timeframe

Most Case Study models are run on an annual basis for a future year. In some Studies, it is instructive to assess how operating parameters change over time, for example over the lifetime of some infrastructure project, and costs and benefits are reported on a whole life basis.

For each Case Study, a single vector and a multi vector configuration are defined on a common basis, such as supplying a set of annual energy demands or managing a network constraint. For both single and multi and vector configurations, care is taken to define an approximately optimal system; this is not a formal optimisation process, but we aim to compare a 'good' multi vector configuration to a 'good' single vector case.

System costs for the multi vector and single vector configurations then define the multi vector value; costs considered in the comparison of multi and single vector cases typically include:

- the **network costs** associated with reinforcement, opex and decommissioning value
- **fuel costs** and the associated **emissions pricing** and
- additional **generation** requirements and other **technology capex** and **opex**
- **revenues from sales** (e.g. electricity, renewable gas), where applicable

Finally the engineering, operational, commercial and regulatory barriers to operating in the multi vector configuration are assessed. This work is developed further in the Work Package 5 report *Barriers to Multi Vector Energy Supply.*

3 Case Studies

In this section, the analysis and modelling carried out for each of the Case Studies is described in detail, and the results presented.

1. A description of the Case Study setting
2. Key case study assumptions
3. The model structure and methodology
4. Model outputs and the associated insights.

3.1 Case 1: Domestic Heat Pumps and Peak Gas Boilers

3.1.1 Introduction

Context

How to decarbonise UK domestic heating, over 85%[2] of which is provided by burned fossil fuels in the home, represents a major challenge in the transition to a low carbon energy system. Heat pumps – powered by low carbon electricity – represent a potential answer; their widespread deployment will however lead to significant growth in peak loads on the electrical distribution system:

- Peak throughput on the gas network is around five times the maximum electrical power flow.
- The *Smart Grid Vision and Roadmap* Report predicts that by 2030 20 GWe, and by 2050 40GWe, of heat pump capacity will be installed in UK homes (6m and 12.5m units) - corresponding to three times the 2015 peak domestic electric demand.

Due to the seasonal variation in heat demand, much of the reinforced grid capacity would be required only during the coldest days of winter, and upgrading the grid to accommodate this demand would be extremely expensive; forecasts range from £20bn to £50bn by 2050 nationally.

Multi vector heat supply represents a potential alternative to infrastructure upgrade; supplying:

- base-load thermal demand electrically using heat pumps, and
- peak demand by gas through the existing gas network.

Aims

In this Case Study, we:

1. Calculate the high voltage (HV) and low voltage (LV) grid reinforcement costs associated with a range of central and high heat pump uptake scenarios.
2. Determine the network upgrade costs avoided through multi vector heat supply,
3. Estimate the increased annual gas and emissions costs, and the reduction in electricity use under multi vector supply.
4. Determine the system benefit delivered by multi vector supply, and discuss the costs of the multi vector configurations.

While the total generation capacity requirements are likely to be reduced by multi vector heat supply, this is not quantitatively assessed here.

[2] 2016 ECUK Data

3.1.2 Scenario Definition and Assumptions

The modelling of this Case Study is based on the City of Newcastle[3]; selected as:

i. Grid topology models built for the ETIs' EnergyPath Networks (EPN) project[4] can be used for the study.
ii. Newcastle comprises areas of varying character – ranging from city centre to sub-urban and semi-rural areas – a broad set of housing archetypes, ranging from small new-build flats to large, poorly insulated detached houses, and a mixture of social demographics.

The model built for this Case Study considers the hourly thermal and electrical demands at each building in Newcastle from 2016 to 2050, and particularly:

- the associated electrical distribution network upgrade costs, given a range of network management options, and
- corresponding fuel and emissions costs,

as heat is substantially electrified.

Methodology

The Case Study model calculates the hourly load on each component in Newcastle's electrical network under of increasing and substantial heat pump uptake, given a range of single and multi vector heat supply alternatives. The city's electrical grid structure - the network topology - and demographic data are taken from the EPN model.

Peak load forecasts are calculated at each network asset; specifically, for each hour across a range of years to 2050, the model:

i. Determines the electrical and thermal demand at each building (domestic and commercial), and the resultant demand on each network component (electrical feeders[5] and substations).
ii. Calculates the share of thermal demand met by heat pumps - as the total number of installed heat pumps increases year-on year - and the corresponding electrical demand.
iii. Identifies those network components which are unable to meet this demand.
iv. Considers the use of gas as a multi vector alternative heat supply; under a range of mooted heat pump control protocols.
v. Assesses the fuel and emissions costs associated with the additional gas combustion.

EPN model data are then used to determine costs associated with the scenario network reinforcement.

We determine grid upgrade costs under two single vector options for heat pump supply:

1. A "Business as Usual" case, in which heat pumps are used much as gas boilers are used now - to meet instantaneous demand - and electrical vehicles (EVs) are charged at the end of journeys.
2. Under more intelligent heat pump operation and EV demand management.

The costs are then compared against their multi vector supply counterparts, where network peak-time thermal demand is supplied using the gas network, with switching controlled by:

3. Real-time smart monitoring of grid loads and substation and feeder line capacities, and
4. Limiting the maximum electrical draw of each heat pump.

[3] Newcastle is a city of around 280,000 inhabitants residing in 138,000 dwellings, and around 19,000 industrial and commercial premises.

[4] EPN is an ETI project, to develop software for use in the planning and pricing of local energy systems.

[5] Feeders' cables connect substations to each other, and to buildings; these will typically be underground in an urban setting.

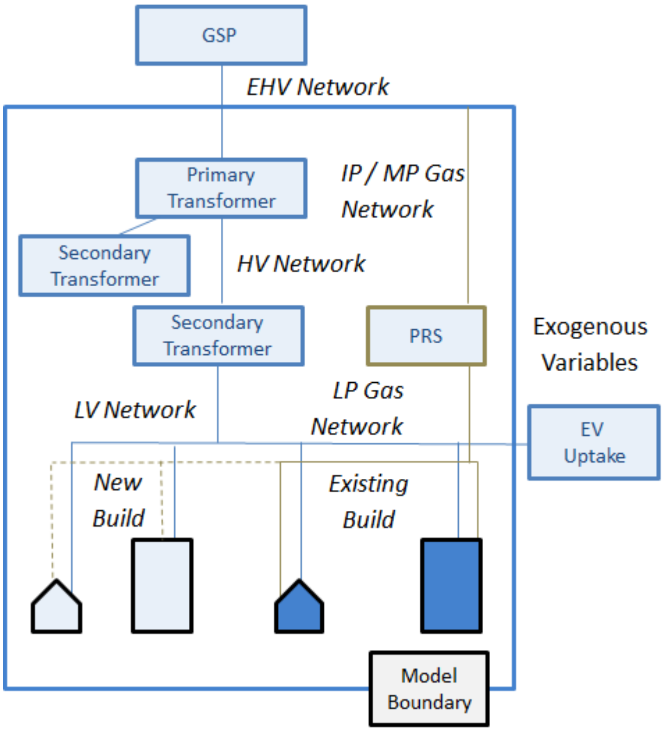


Figure 1 -Model Schematic

Key elements of the modelling methodology are described in detail below.

Fuel and Carbon Prices

Hourly power prices are taken from the ESME / PLEXOS model Decarbonisation Scenario (described in appendix 9.1) in which 65% of UK 2050 domestic thermal demand is met by heat pumps, a similar figure to our reference case heat pump uptake scenario. The electrification of heat drives increasing diurnal power price variation, particularly in winter. A gas price of £30/MWh is taken from the BEIS projections. As the subject of this analysis is the system level benefit, these prices are used to assess the fuel and emissions costs associated with multi rather than single vector operation, and no adjustment is included for domestic or industrial and commercial network connection charges.

A carbon price of £200/tonne[6] is used throughout this analysis, to:

- Reflect a future in which electrification of heat is strongly incentivised
- Discourage gas combustion, even at times of low heat pump CoP.

We note that in this analysis, heat pump uptake is a model level, and we do not consider endogenously consumer response to fuel prices, though the economics of heat pump switching are discussed in the section on Fuel Costs.

Electrical Network Modelling

Newcastle's homes and industrial and commercial premises are served by a network of 16 primary and 760 secondary substations. Each primary substation serves between 20 and 80 secondary substations and around 150 dedicated high voltage (HV) industrial and commercial connections; each secondary substation serves around 180 homes and 20 low voltage (LV) industrial and commercial customers.

[6] The central BEIS carbon price projection rises by £7 per tonne per year from 2030 to 2050 - from £74/tonne to £212/tonne.

We have synthesised the electrical network structure in the EPN model:

i. A nearest neighbour algorithm is used to associate model nodes to their nearest substation of the appropriate voltage – HV industrial and commercial connections connect directly to their nearest primary substations, while LV industrial loads and domestic users connect to secondary substations.
ii. Electrical feeder routes follow the road layout; this determines their length.

Demographic Data

Twenty housing archetypes are defined within the load growth model (16 existing build and 4 new build), derived from analysis of English Housing Condition Survey data and SAP-based energy modelling. Each archetype is described by a set of features which include the size, thermal efficiency and heating technology of the dwelling.

It is assumed that each year, 0.5% of the build stock is demolished and 1% of the total 2016 stock is added as new build; resulting in a decrease in the average thermal demand per household. An assumption has also been made for the rate of improvement in the thermal efficiency of the existing stock, based on government projections and Carbon Trust data.

Total Energy Demand

Aggregate domestic thermal and electrical demands for the housing archetypes are determined in the SAP model for the housing archetype set specified above. Overall industrial and commercial demand is calculated using VOA floor space data and CIBSE benchmarks on gas and electricity use per square metre; the total loads values for Newcastle are calibrated against national postcode and local authority level datasets. The total appliance demand is adjusted by the energy efficiency projections from the BEIS Heat Strategy.

Energy Demand Profiles

Hourly electrical appliance demands for each building are scaled to the load profile of the primary substation to which they connected, taken from the EPN Model. Thermal demand profiles are taken from the Carbon Trust micro-CHP field trial data – for those homes heated using gas and heat pumps – and from the Elexon Class 2 profile for homes which use electric storage heaters. High quality profile data on heating in industrial and commercial buildings is not available, so the model thermal demand of these premises follows the domestic profile[7].

The managed single vector scenario assumes thermal storage can be used to smooth the demand profile of a heat pump; implemented in the model as shown below. The area between the instantaneous and managed curves between 14:00 and 22:00 is around twice the hourly maximum value, and so represents around two hours of peak HP output as storage – between 50 and 150 litres depending on the building thermal demand.

[7] How this affects model finding is explored in the Applicability section.

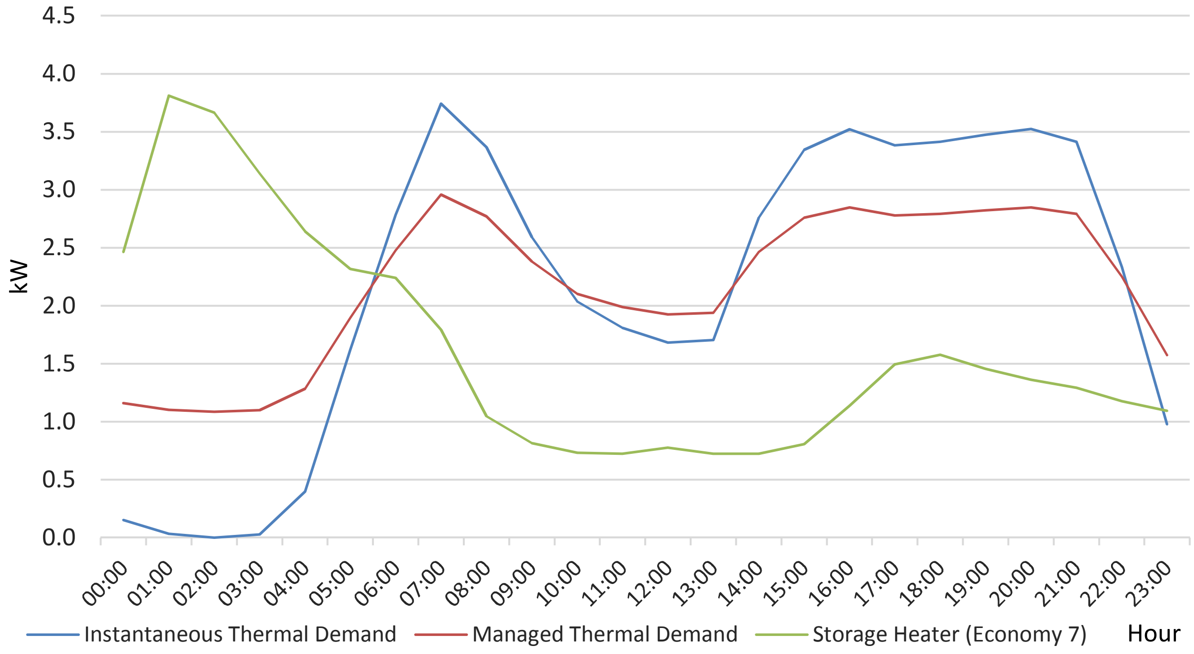


Figure 2 – Heat Demand Profiles Scaled to 2050 Average Total

Conversion of Heat Pump Thermal and Electrical Demand – CoP

Domestic buildings are assumed to use air-source heat pumps; the coefficient of performance (COP)[8] of these varies with the air temperature - between 1.1 at below 0℃ and 4.2 at above 15℃ - for supply to existing building stock at a temperature of 70℃[9]. Future peak electrical demands will therefore occur where peak thermal demand coincides with very low air temperatures; at which point heat pumps run at a CoP of not much better than one. Industrial and commercial units are modelled as water or ground source units, which draw heat from a reservoir at a constant annual temperature of 10℃, at a corresponding CoP of 3.0. CoP data are taken from the Emerson Climate *Copeland* and *Select* models, and shown in appendix 8.2, and their effect on model findings is discussed in the Applicability section.

Heat pumps using transcritical CO_2 as a working fluid must operate at a greater sink-to-source temperature difference, which resolves some of the problems with switching UK build stock to heat pumps; these are explained in appendix 5.2.

Electrical Demand Diversification

Substation electrical load profiles inherit a degree of diversification corresponding to hundreds of connections, with 2016 average peak demands of 800W per house, ranging between 0.4 and 3.8kW. These may be overly diversified for small LV substations, but as the same profiles are used to calculate current network capacity and future requirements, our findings are not very sensitive to this assumption, (for reference, the NPG electrical network diversification factors are shown in appendix 5.3.2).

Thermal Demand Diversification

The Carbon Trust profiles above imply a 2016 peak thermal demand of around 3.3kW per household across the build stock, varying between 1.7kW (for small new build) and 8.3kW (for large, very old houses).

[8] The CoP is a generalised measure of efficiency, given by the total useful heat out over electrical energy in.

[9] The corresponding CoPs for the new build temperatures of 55℃ are 2.4 and 5.4 respectively. An hour's pasteurisation at temperatures above 60℃ using an immersion heater may be required on a roughly weekly basis to make water at this temperature free of Legionella and other bacteria; this is not included in the model.

Given the degree of diversification inherited in these profiles, and the substation and feeder connection numbers, no further diversification is applied to thermal-electrical loads at grid components in this analysis.

Heat Pump Uptake

Each house type is associated with a likelihood of upgrading to heat pump (based on thermal efficiency, existing plant and the socio-economic demographic data). Total 2050 domestic and I&C heat pump uptake are model levers, uptake is distributed across the building stock in proportion to the upgrade likelihood; in the reference heat pump uptake scenario, 100,000 domestic and 5,500 industrial and commercial heat pumps are installed by 2050[10]; corresponding to installation in:

- 39% of homes (and 13% of industrial and commercial premises) by 2030,
- 83% of homes (and 28% of industrial and commercial premises) by 2050.

The thermal demand of heat pump equipped homes accounts for a slightly smaller share (70%) of 2050 total, as newer buildings - built to higher thermal efficiency standards - are more likely to use heat pumps.

90% of heat pumps are installed in houses connected to the gas grid; once heat pumps are installed these households are potentially able to move thermal demand from the electric onto the gas network. These **multi vector households** are the key focus of this study.

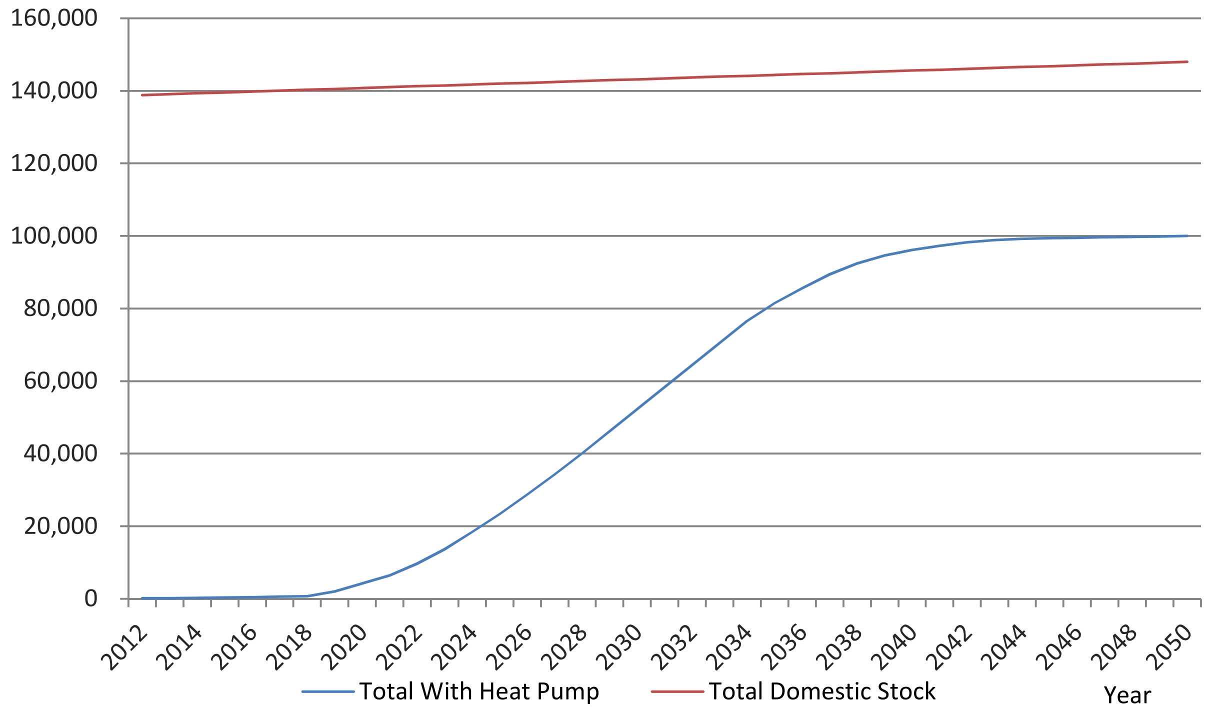


Figure 3 - Projected Housing Stock and Heat Pump Uptake

[10] In BEIS heat pump uptake projections, those generated for the Smart Grid Forum Work Stream 3 modelling and scenarios generated by the ESME model, industrial and commercial heat pump uptake is modest compared to the domestic switchover.

Electric Vehicles

Electric vehicle (EV) uptake projections are based on BEIS central case; the national scenario is scaled to the population of Newcastle, and vehicle demand is distributed across primary and secondary substations by domestic connection share.

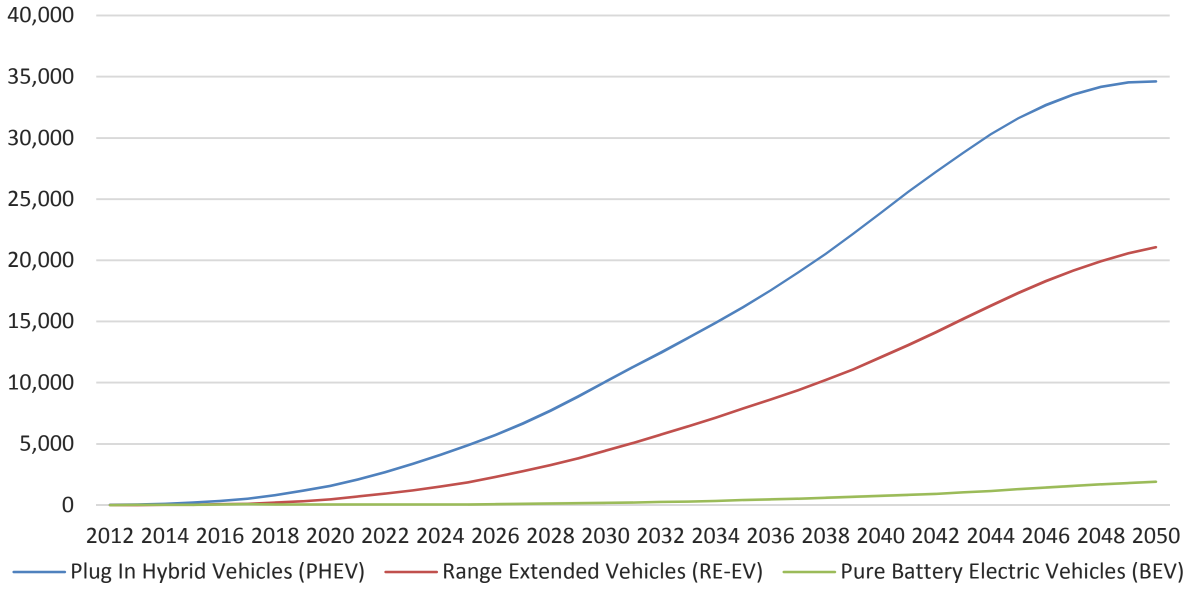


Figure 4 - BEIS Central EV Uptake Scenario Scaled to Population of Newcastle

Two charging profiles - from the *National Transport Survey* and *ETI Consumers and Infrastructure EV Project* – are included:

i. an unmanaged **Charge at end of trip** option, and
ii. a smarter **Overnight Charging** profile.

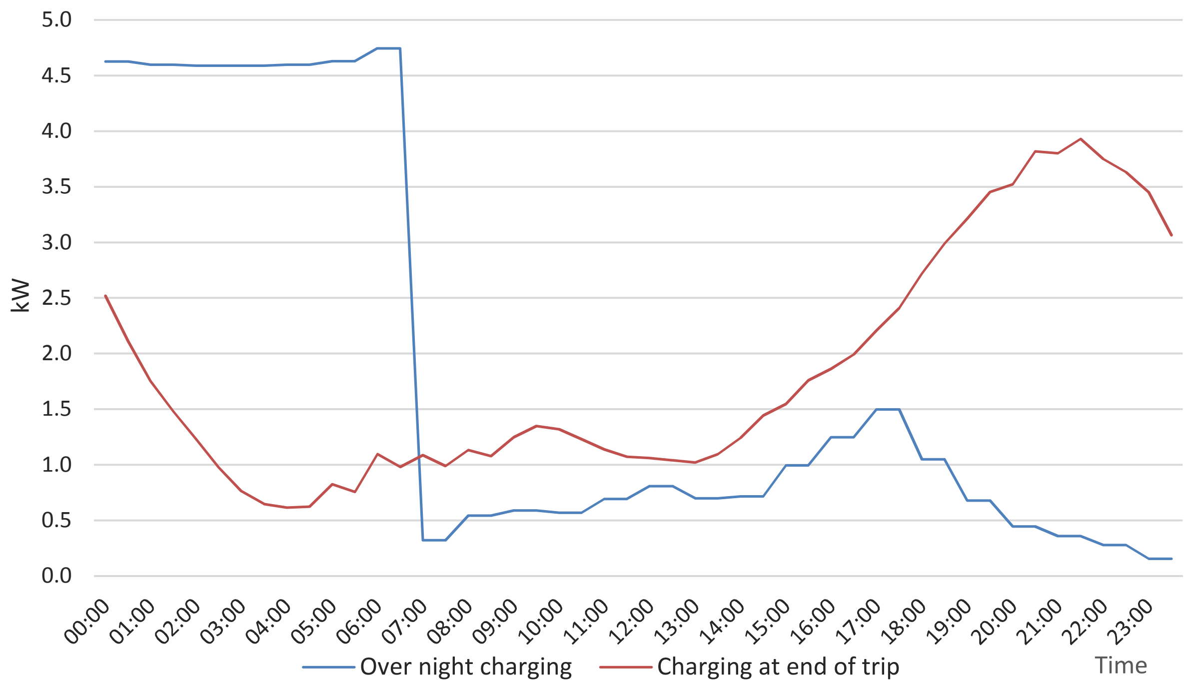


Figure 5 – 2050 Average Vehicle EV Charging Profiles

Grid Component Upgrade Requirement and Cost

Total network upgrade requirement is determined as follows:

i. The 2016 model run determines the current capacity for each component; the size of each component is the smallest sufficient to meet the 2016 peak load with 25%[11] headroom.
ii. The hourly peak out to 2050 determines the capacity upgrade required.

Network costs and capacities are taken from the EPN model, which defines a number of states for each grid component – feeder or substation – with each state corresponding to a maximum electrical capacity. For each component, the upgrade to a larger capacity is associated with a cost; the network reinforcement cost is given by the total transition costs across all network components. EPN model costs and capacity data are explained in appendix 9.2. Primary and secondary substations capacities and costs are shown below.

Table 1 – Primary Substation States and Associated Capacities and Costs

Component State	Capacity (MW)	Materials (£)	Overheads (£)	Upgrade Cost (£)	Capacity Upgrade Cost (£/MW)
0	14.40	925,000	198,800		
1	28.80	1,850,000	198,800	1,123,800	78,040
2	43.20	2,774,900	596,500	1,521,500	105,660
3	86.40	5,549,900	198,800	2,973,800	68,840
4	172.80	11,099,800	397,700	5,947,600	68,840

Table 2– Distribution Substation States and Associated Capacities and Costs

Component State	Capacity (MW)	Materials (£)	Overheads (£)	Upgrade Cost (£)	Capacity Upgrade Cost (£/MW)
0	0.40	61,800	13,300		
1	0.64	65,200	13,300	16,700	69,540
2	0.80	67,500	13,300	15,600	97,440
3	3.20	260,900	13,300	206,700	86,120
4	16.0	1,349,600	13,300	1,102,000	86,090

Substation upgrade costs are cumulative, so that the cost of upgrade from one state to another is given by the difference in material costs of those states, plus the overhead costs. Costs for feeder upgrades are tabulated below; as these costs and capacities vary with feeder length they are indicative only. Unlike substations, feeder upgrade costs are not cumulative; upgrade incurs the whole material and overhead costs.

[11] This figure is taken from discussions with Northern Power Grid (NPG), we note no future headroom requirement is included. In the Sensitivity section, we also review a no future headroom increase scenario.

Table 3– Indicative LV Feeder States and Associated Capacities and Costs

Component State	Capacity (MW)	Materials (£)	Overheads (£)	Upgrade Cost (£)	Capacity Upgrade Cost (£/MW)
0	0.13	13,300	36,500		
1	0.20	16,800	36,500	53,300	761,300
2	0.28	20,000	36,500	56,500	706,260
3	4.46	320,000	36,500	356,500	85,280

Demand Management Solutions

This project investigates to what extent the single or multi vector management of thermal demands can mitigate electrical network upgrade requirements as heat is substantially electrified. To quantify this two single vector cases and two multi vector cases are presented:

i. A **High Electrification** single vector scenario, in which heat pumps supply instantaneous thermal demands – where heat pumps are fitted in gas heated homes the boiler is removed. Households with electric vehicles charge them following the end of their return home.

ii. A **Managed Load Growth** single vector scenario in which thermal demand profiles are smoothed to represent intelligent storage use, and electric vehicles are charged overnight - away from times of high electrical demand.

iii. A **Smart Multi Vector** scenario in which heat pumps can be turned down, or switched off, at times of high load on substations. The required thermal demand "gap" is then met by legacy boilers or hybrid gas and electric heat pumps (the thermal demand of those houses not connected to the gas grid is still supplied electrically)[12].

    This scenario determines the "size of the prize", the upper bound on the grid reinforcement cost avoided by using gas to meet peak time thermal demand. In line with this approach, heat pump demand is taken off the grid in increasing CoP order, so that:

    i. existing stock (high- temperature) heat pumps are the first to be turned down, followed by
    ii. new build (lower temperature) heat pumps, and finally
    iii. commercial and industrial heat pumps.

    Further requirements of the **Smart Multi Vector** control system are discussed in appendix 6.1.1.

iv. A **Constrained Heat Pump Demand** multi vector scenario; an alternative, less control intensive multi vector solution in which heat pumps installed in homes connected to the gas network are sized to 50% of their installation year peak electrical demand, and additional demand is met using gas boilers[13].

[12] Heat pump management is based on substation demand; no corresponding monitoring of feeders is considered. Demand management is considered at substations, rather than buildings; the model does not differentiate between 1kW of turndown at a single connected heat pump and 0.1kW of turndown at 10. Vector switching is not considered where it would reduce the fraction of thermal demand supplied by heat pump to below 65%.

[13] Since thermal demands are highest and CoPs are lowest in winter, and peak electrical demand (rather than thermal output) defines the heat pump size, this limit is breached for only around 1,000 hours annually. A 50% peak sized heat pump supplies around 90% of a property's total annual thermal demand – the same share of electrically supplied heat as in the **Smart Multi Vector** scenario.

Reinforcement costs are calculated to the peak demand between 2016 and 2050, intermediate costs are not considered. Undiscounted reinforcement costs are given in the following analyses, with the difference in required reinforcement costs the key metric of benefit.

Table 4 – Summary of Demand Management by Scenario

	Scenario	Demand Management
Single vector configurations	**High Electrification**	Loads are unmanaged, heat pumps are used in much the same way that gas boilers are used now, and EVs are charged at the end of their journeys.
	Managed Load Growth	HP demand smoothed; peak thermal output is reduced by around 20%. EVs are charged overnight, away from peak system demand.
Multi-vector configurations	**Smart Multi Vector**	Heat pump demand is turned down in response to constraints at upstream substations. EVs are charged as in the **Managed Load Growth** scenario.
	Constrained Heat Pump Demand	Heat pump maximum electric draw is limited to half its potential annual maximum. EVs are charged as in the **Managed Load Growth** scenario.

3.1.3 Case Study Analysis

Evolution of the Electrical System

Before the electrification of heat is included, electrical demand is projected to fall year-on year to 2050; domestic demand remains roughly static out to 2050, with moderate appliance efficiency improvements offset in part by growth in the total building stock. Industrial and commercial demands are projected to fall more sharply.

Taken together:

i. appliance efficiency improvement,
ii. electrification of transport, and
iii. increase in the total building stock

lead to a city-level decrease in annual electricity demand of 300GWh – a fall of 20% – over 35 years, and domestic demand reduction of around 50 GWh – around 10% - over the same timeframe.

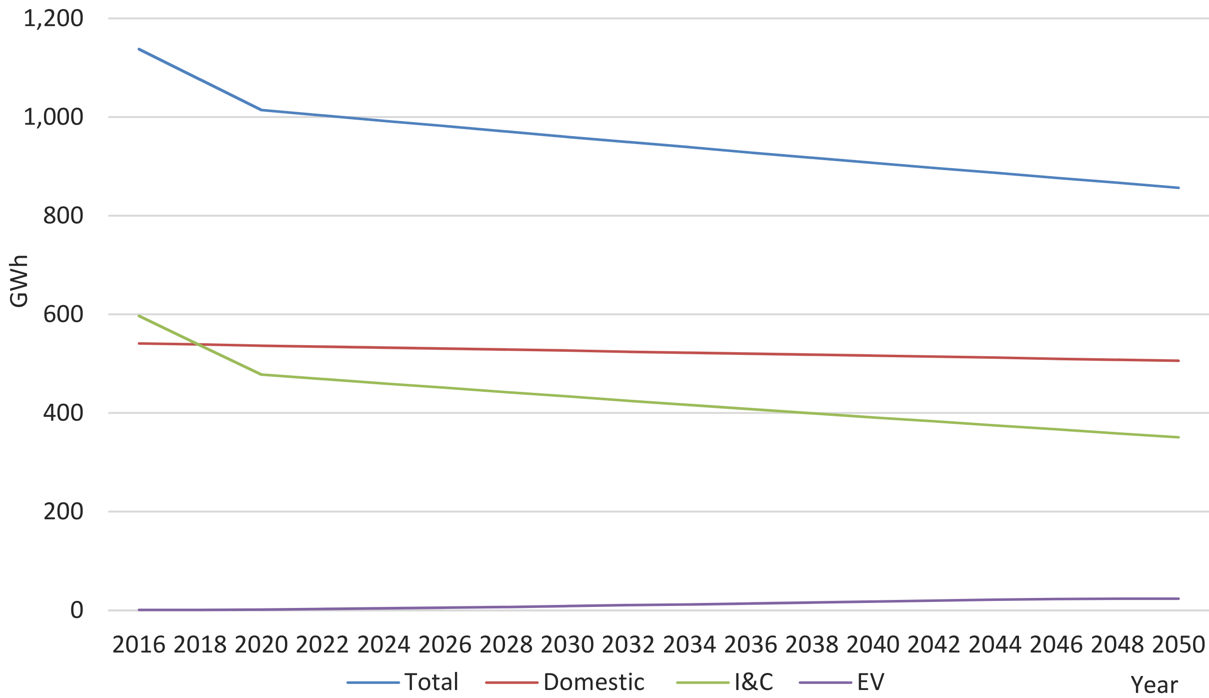


Figure 6 – Projected Newcastle Electrical Demand not including Electrification of Heat

The principal driver of network capacity upgrade requirement then is heat pump uptake; our reference case considers the thermal electrification of 100,000 homes by 2050 – corresponding to a total of 1.0 TWh of heat being provided by heat pumps by 2050, and an electrical system load increase of 420 GWhe - around 40% of the 2016 total.

Then city total peak demand breakdown evolution is shown in Table 5 - Newcastle Peak Electrical Demands to 2050 (MWe) and Figure 7; the seasonal distribution of heating demand, and the associated variation in heat pump CoP, result in a doubling of peak network demand by 2050, even as total electrical system throughput remains roughly constant. Times of greatest heat pump demand coincide other peaks (winter weekday evenings), and heat pump power demand grows to comprise around two thirds of the system peak,

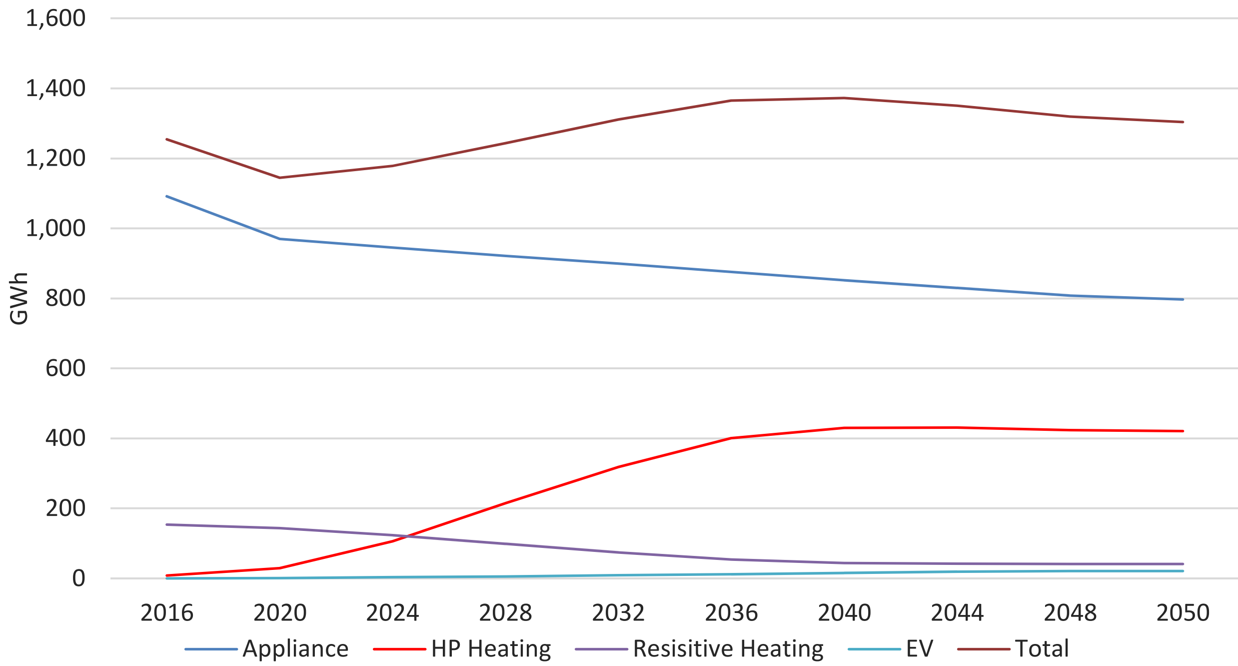


Figure 7 – Total Electrical Demand Breakdown to 2050

Table 5 - Newcastle Peak Electrical Demands to 2050 (MWe)

Year	Peak Demand	Appliance Max	Heat Pump Max	Resistive Heating Max
2020	223.4	191.9	20.8	53.9
2024	256	187.3	82.6	46.8
2028	328.2	182.6	170.5	37.5
2032	407.2	178	262.4	28.1
2036	470.9	173.4	335.4	20.5
2040	493.3	168.9	363.2	16.8
2044	488.3	164.3	361.8	15.8
2048	474.8	159.8	351.4	15.7
2050	468.3	157.6	346.5	15.6

Total electrical throughput rises only slightly, but peak demand doubles, as heat is electrified.

Component Load Growth

HV System

Our model:

i. distributes the heat pump uptake across the city's primary (HV) and downstream secondary (LV) substations,
ii. determines the peak load at each, and the feeder cables that connect to them.

The 16 HV substations and their peak loads for each of the 4 heat supply alternatives, are shown below.

In the **High Electrification** scenario, peak growth factors[14] are not uniform – average HV peak loads increase to around 210% of 2016 levels, with a range of between 90% and 250% (a reduction is seen at the University substation where heat pumps mainly displace electrical resistive heating).

Those substations which require upgrade in the **High Electrification** case –those that see demand management in the **Smart Multi Vector** scenario – are indicated in bold; at half of these – Fossway, Kenton, Longbenton and Westerhope - the **Constrained Heat Pump Demand** peaks also exceed 2016 capacity.

Table 6 – Peak Load Growth on the 16 Primary Substations in Newcastle

Primary Substation Name	# Attached Secondary Substations	2016 Peak Load (kW)	Peak Load (kW) Scenario				Peak Growth Factor[14]
			High Electrification	Managed Load Growth	Smart Multi Vector	Constrained Heat Pump Demand	
Benwell	69	24,200	55,700	46,900	43,200	38,400	230%
Blucher	52	17,600	36,200	31,100	28,800	26,500	206%
Breamish Street	54	19,700	24,300	21,000	24,300	20,500	123%
Close	17	3,700	5,000	4,400	5,000	4,000	135%
Corporation Street	70	26,800	34,600	30,500	34,600	28,600	129%
Educational Precinct	55	14,600	26,900	22,900	26,900	19,900	184%
Fawdon	49	18,600	37,500	31,400	28,800	26,900	202%
Fossway	71	22,800	53,200	44,800	28,800	36,700	233%
Kenton	66	17,900	44,800	37,400	28,800	30,700	250%
Longbenton	75	18,900	43,800	36,800	28,800	30,600	232%
Newburn Haugh	24	5,300	7,400	6,500	7,400	5,800	140%
Newcastle Airport[15]	18	5,600	13,300	11,100	13,300	9,000	238%
Pilgrim	32	8,600	10,400	9,300	10,400	8,900	121%
University	14	4,500	4,200	4,000	4,200	4,000	93%
Walker	31	7,500	19,300	16,100	14,400	13,100	257%
Westerhope	63	21,200	51,800	43,300	28,800	36,700	244%

[14] The peak growth factor is the ratio of the peak demand to 2050 in the **High Electrification** Scenario to the 2016 value.

[15] As 14.4MW is the lowest model capacity for a primary substation, Newcastle Airport operates within its 2016 headroom even as its peak load grows significantly.

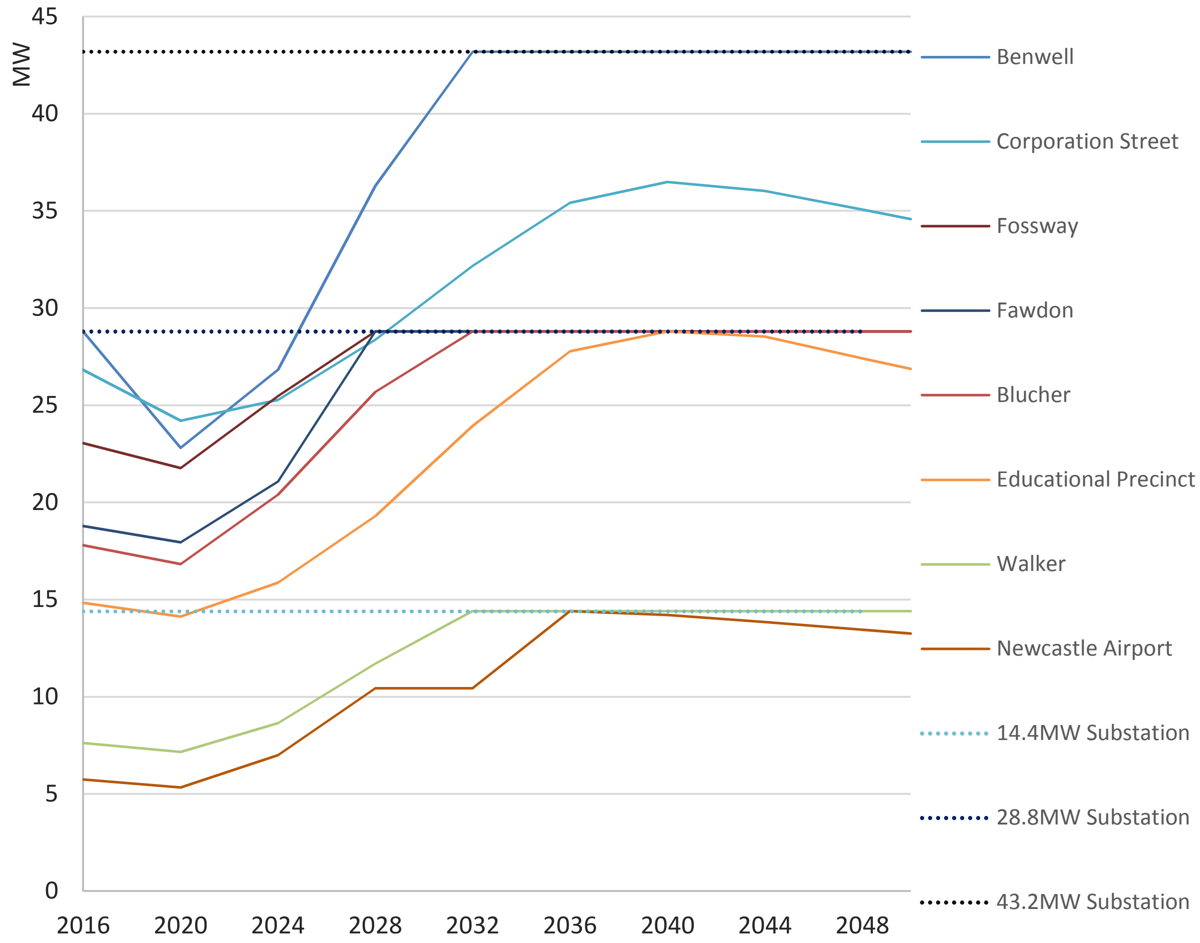


Figure 8 – Smart Multi Vector Load Growth at a Range of Primary Substations

LV System

Housing demographics are not uniform across the city, and secondary substations see a greater range of peak growth factors than their primary counterparts. Average LV substation peak load increases to around 220% of the 2016 value, though it can be as high as 380% where the load is dominated by large houses that transition rapidly to heat pumps.

Conversely, for substations dominated by:

i. small, highly efficient blocks of flats,
ii. resistive heating, or
iii. industrial and commercial users,

future efficiency savings largely offset the load growth associated with heat pump uptake. At particular, primary and secondary substations dominated by industrial and commercial demand no capacity upgrades are required before 2050, even where thermal demand is entirely unmanaged.

Peak load growth curves indicative of the two ends of this spectrum are shown below for:

i. Forth Bank, a distribution station near the Tyne Bridge serving 680 large, poorly insulated houses in the centre of town, and
ii. Waterloo Square, a substation serving a mixed residential and commercial complex 500m to the northwest.

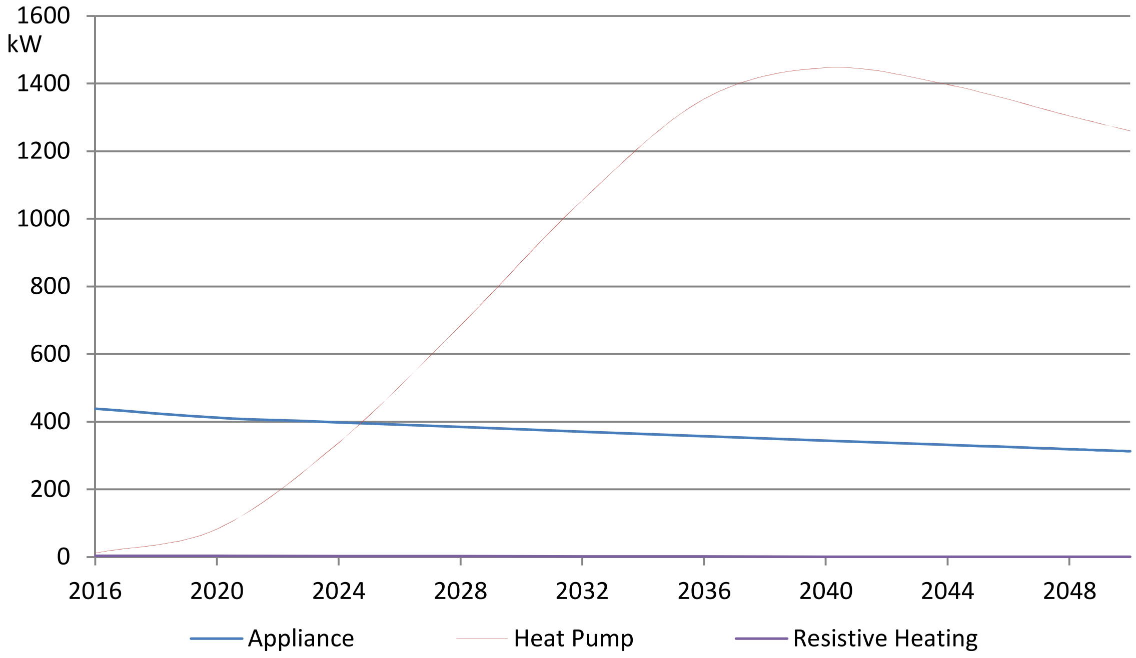


Figure 9 – Unmanaged Peak Load at Forth Bank LV Substation

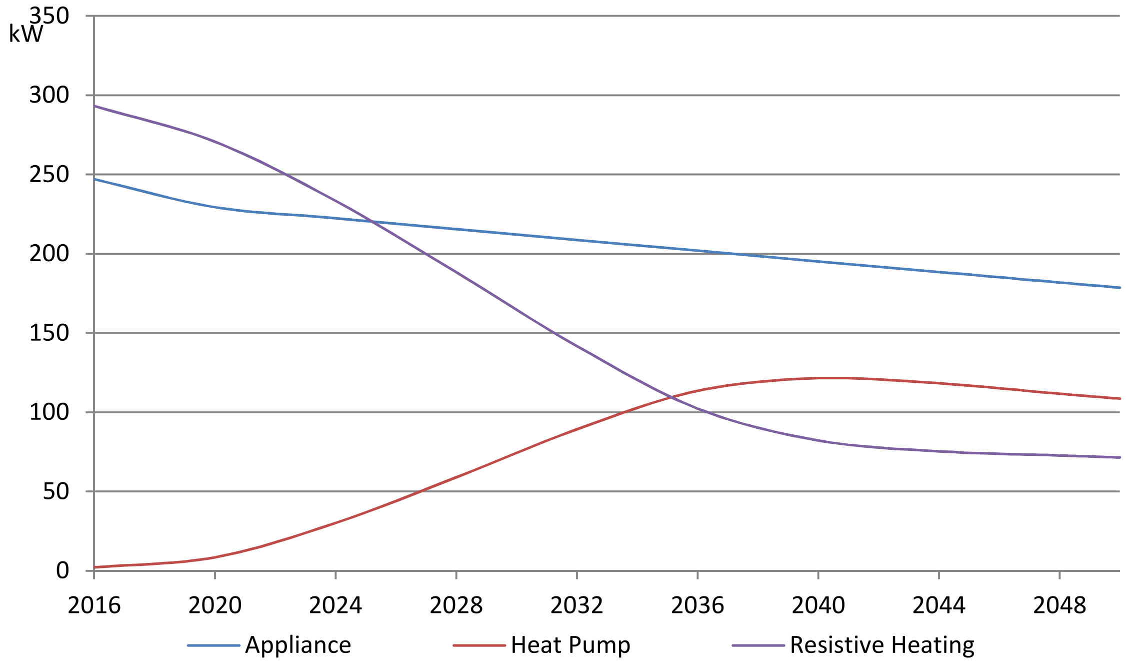


Figure 10 – Unmanaged Peak Load at Waterloo Square LV Substation

As at the city level, growth in substation level peak demand is largely driven by heat pump uptake; some peak thermal demands are over twice the existing substation capacity. Substantial variation across the city in demographics and demand levels means the situation across substations is far from uniform.

Multi Vector Benefit

We present here, for each demand management solution:

i. the network upgrade costs, and
ii. the environmental costs associated with multi vector heat supply.

Control system costs are not included in this analysis, though they are qualitatively discussed in the following section.

Grid Reinforcement Costs

Reinforcement costs by scenario are shown in Table 7.

City level costs associated with grid upgrades in the **High Electrification** scenario are considerable:

i. Over half the HV and 40% of the LV substations must be upgraded, and
ii. 9% of the HV and over a quarter of the LV feeders must be replaced by 2050

at a total cost of £393 million.

In the **Managed Load Growth** single vector scenario, reinforcement is required at around two thirds of the components that are upgraded in the **High Electrification** case. Reinforcement costs are reduced by a similar fraction, to just over £250 million.

The **Smart Multi Vector** solution maintains all HV and LV substations at their 2016 capacities, though 5 HV, and nearly 10% (338) of LV feeders, must be upgraded - at a total cost of £110 million.

Under the **Constrained Heat Pump Demand** implementation, fewer feeders but more substations are upgraded than in the **Smart Multi Vector**, incurring a reinforcement cost of around £140 million.

Table 7 – Summary of Scenario Upgrade Costs

Scenario	HV System Costs (£m and number)		LV System Costs (£m and number)		Total
	Substation Upgrades	Feeder Upgrades	Substation Upgrades	Feeder Upgrades	
High Electrification	24.3 (9)	21.8 (25)	50.3 (327)	297 (1036)	393.4
Managed Load Growth	18.0 (8)	9.1 (8)	32.9 (263)	194.7 (642)	254.6
Smart Multi Vector	0 (0)	6.5 (5)	0 (0)	106.9 (338)	113.4
Constrained Heat Pump Demand	6.1 (4)	6.7 (4)	19.4 (178)	108.7 (324)	140.9

The **Smart Multi Vector** solution saves upwards of £280m in avoided grid reinforcement costs, and the **Constrained Heat Pump Demand** scenario saves around 10% less at just over £250m, compared to the **High Electrification** approach. These figures correspond to savings of £3,000, or £2,700, per multi vector household respectively.

Of the multi vector solutions, **Smart Multi Vector** costs around £32 million - £300 per household - less than the **Constrained Heat Pump Demand** alternative; the latter would however have lower implementation costs due to:

i. the lack of a sophisticated control system and
ii. the smaller heat pump size.

£300 per household therefore represents a lower bound on smart demand management value. However, in each scenario feeder upgrade costs – particularly LV feeders - dominate other upgrade costs, and all the **Smart Multi Vector** scenario upgrade– over £110m – comprise feeder replacement costs. Were feeder, as well as substation, loads and capacities monitored these upgrade costs might also be mitigated – though a more sophisticated monitoring and control system would be required.

The two multi vector implementations presented here are not mutually exclusive; a hybrid solution may be most cost effective depending on relative control system, fuel and carbon prices. Householders who buy an undersized heat pump (and maintain a peak gas boiler) effectively choose the unmanaged over the managed multi vector solution. In so doing, they reduce the potential value of the smart control system, their saving on unit cost may offset this.

Although generation implications are excluded from the scope of this study, at the system level there are likely to be significant benefits to electrical generators associated with the ability to demand management over half of UK thermal demand.

Grid reinforcement costs in the single vector scenarios (£393m and £254m) equate to £4,400 and £2,800 per household respectively, and represent upper and lower bounds on grid reinforcement associated with the unmonitored, completely electrified supply of heat.

Multi vector heat supply avoids between £140 million and the full network upgrade cost - between £1,500 and £4,400 per household. This far exceeds the lifetime cost of installing and/or maintaining a (top-up) boiler, though the multi vector solution implementation will require a sophisticated control system, the costs of which are not included here.

At a network upgrade cost of only £32m more than the smart alternative, unmanaged **Constrained Heat Pump** multi vector heat supply may be the most cost effective grid management option, particularly:

i. if the intelligent control system is expensive, and
ii. if heat pump prices comprise largely marginal unit, rather than installation, costs.

However, a **Smart Multi Vector** system which monitors loads at feeders (as well as substations) could potentially avoid **all** grid upgrade costs; the smart benefit then increases by £115m - from £300 to £1,250 per household.

How best to implement a multi vector solution will therefore depend on the control and monitoring system costs, and whether a smart control system monitors feeder, as well as substation, loads.

In the following section, we review the fuel and environmental costs of multi vector gas use. As the grid avoided costs are substantial, a high carbon price is chosen to emphasise the environmental costs of multi vector gas use, and be consistent with policy drivers of large-scale heat pump uptake.

Running Costs

In this section, we consider an obvious concern with multi vector fuel switching; that it undoes the environmental benefit of the electrification of heat – as electrical generation decarbonises it makes gas heating increasingly carbon intensive relative to heat pump use.

Total fuel costs – at buildings connected to the Fossway HV substation and for the entire city – are tabulated below across supply alternatives. The share of heat supplied through the electrical and gas vectors is also shown. This analysis is calculated using:

i. the BEIS projected wholesale gas price of £30/MWh, and
ii. the PLEXOS derived system level wholesale electrical price time series.
iii. A carbon price of £200 per tonne[16]

Table 8 –Annual Fuel Demand, Emissions and Associated Costs at Fossway Primary Substation

Scenario	Total Electrical Demand (GWh)	Electrical Cost (£m)	Total MV Gas Demand (GWh)	Gas Cost (£m)	Fuel Switching Emissions (tonnes)	Carbon Cost (£m)	Total Cost (£m)
High Electrification	53.0	8.47	0.0	0.00	0	0.00	**8.47**
Managed Load Growth	53.8	8.29	0.0	0.00	0	0.00	**8.29**
Smart Multi Vector	44.8	7.83	13.0	0.39	2,830	0.57	**8.79**
Constrained Heat Pump Demand	49.5	8.20	5.3	0.16	1,160	0.23	**8.60**

Table 9 –Total Annual Heating Fuel Demand, Emissions and Associated Costs across Newcastle

Scenario	Total Electrical Demand (GWh)	Electrical Cost (£m)	Total MV Gas Demand (GWh)	Gas Cost (£m)	Fuel Switching Emissions (tonnes)	Carbon Cost (£m)	Total Cost (£m)
High Electrification	396	68.7	0	0.0	0	0.0	**68.7**
Managed Load Growth[17]	401	67.3	0	0.0	0	0.0	**67.3**
Smart Multi Vector	365	66.3	48	1.5	10,500	2.1	**69.9**
Constrained Heat Pump Demand	369	66.7	43	1.3	9,280	1.9	**69.8**

[16]. The central BEIS carbon price projection rises by £7 per tonne per year from 2030 to 2050 - from £74/tonne to £212/tonne.

[17] As heat pump demand is moved away from peak demand period (afternoons and evenings) average CoPs fall, so that the overall electrical demand is higher in the **Managed Load Growth** than in the **High Electrification** scenario. However, the total electrical spend decreases as demand is moved away from times of peak demand and associated higher prices.

Smart Multi Vector demand management at Fossway is associated with:

i. additional emissions of 2,800 tonnes CO_2 annually[18]
ii. additional fuel and emissions costs of £320,000 per year

compared to the **High Electrification** case. These costs represent 8% of the multi vector substation upgrade saving of around £3.9m.

At the city level the **Smart Multi Vector** fuel and emissions costs total £1.2m more than their **High Electrification** counterparts, the avoided system upgrades – between £115m and £280m - are around 100 times this figure. Indeed, if the additional network required in the single vector case incur operational costs of 0.4%[19] of the capital costs per year, the fuel and emissions savings are offset by the additional maintenance and running costs.

By design, the running costs of the **Constrained Heat Pump Demand** and the **Smart Multi Vector** solution are the same.

City wide, multi vector heat supply avoids 2 orders of magnitude more in network reinforcement than it incurs in annual emissions cost. However, in rare cases, long term savings may be realised by upgrading components rather than moving peak heat demand onto the gas network.

Multi Vector Implementation

In this section, we discuss

i. the capability requirements and likely cost of the control system required for the Smart Multi Vector scenario.
ii. Whether such a system might instead be used to control a single vector storage based solution.

Control System Requirements

Smart Multi Vector heat supply data at Fossway - the primary substation with the greatest degree of heat pump driven peak growth - are shown in Table 10 and Figure 11. Switching is confined to periods of up to a few consecutive hours in winter months, with:

i. Some thermal demand supplied by gas for 1,100 hours in the year.
ii. 85% of multi vector households'[20] thermal demand met electrically.

The peak in the centre of Figure 10 is associated with a load shedding event between 12:00 and 21:00, in which between 25 and 50% of heat demand is moved off the electrical system – this nine-hour event is the longest modelled. Realising the **Multi Vector** savings modelled above through demand management therefore requires that head demand can be moved from the electrical to the gas vectors on an hourly resolution.

Unmanaged single vector peak load exceeds the total 2016 substation capacity at only 7 of the HV, and 420 of the LV substations, so that in addition to a high temporal control resolution on fuel switching, a high spatial resolution is required by the control system (see also the discussion in appendix 6.1.1).

Peak load growth at a range of HV substations is shown in Figure 8; where 2016 capacity is exceeded, this typically occurs around 2030 – this is therefore the latest point at which the fully functioning fuel switching solution would need to be in place to realise the full multi vector savings.

[18] The 2040 BEIS projected carbon emissions associated with the displaced 1.2GWh of electricity - around 50 tonnes - are less than 2% of the gas heating value, and so omitted from this analysis.
[19] Taken from the EPN model.
[20] Those buildings with heat pumps installed that are also connected to the gas network

Table 10 – Multi Vector Fuel Switching at Fossway under the Smart Multi Vector Scenario in 2050

Month	Gas Demand (MWh)	Gas Carbon Emissions (tonnes CO_2)[21]	Gas Emissions Cost (£ '000)	Heat Pump Electrical Demand (MWhe)
January	4,686	1,020	204	7,646
February	4,077	887	178	7,034
March	1,535	334	67	7,227
April	158	34	7	4,580
May	0	0	0	2,540
June	0	0	0	899
July	0	0	0	694
August	0	0	0	999
September	0	0	0	1,150
October	0	0	0	2,882
November	636	138	28	5,188
December	1,403	305	61	6,051
Total	**12,495**	**2,720**	**544**	**46,892**

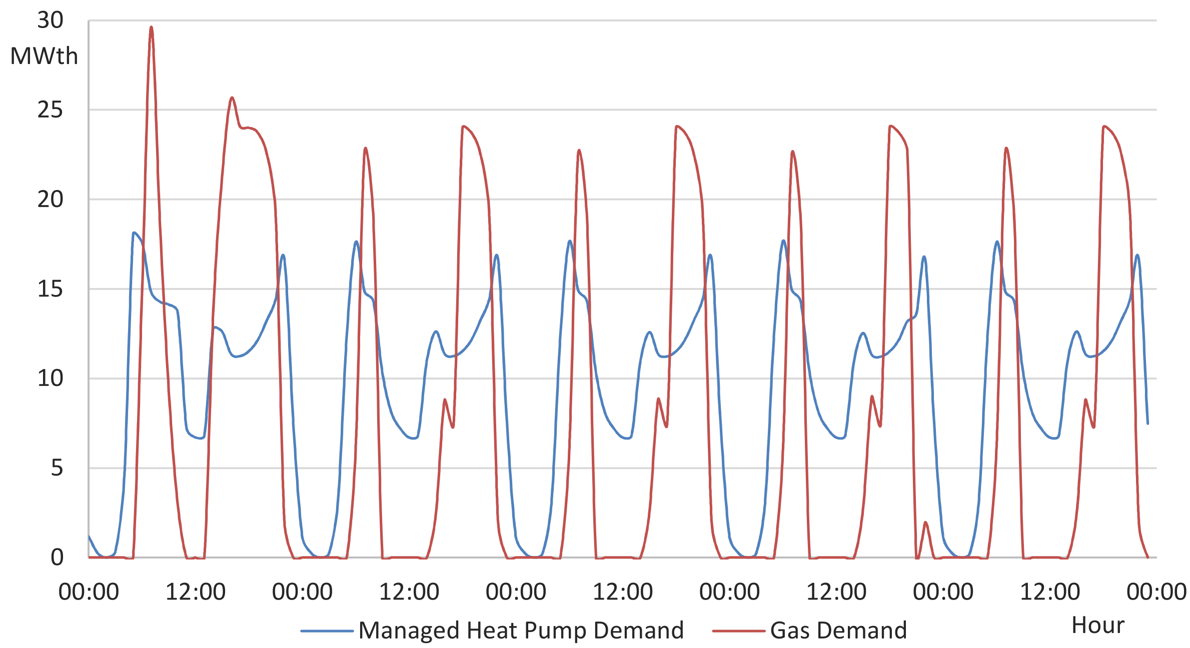


Figure 11 –Smart MV Heat Supply at Buildings Connected to Fossway, 3rd to 8th January 2040

[21] Gas boilers are assumed to operate at thermal efficiency of 85%, and consequent carbon intensity of 220 gCO_2/kWh.

Building energy management systems (BEMS)

The assessed smart multi vector heat supply implementation requires real time communication between network operators and building energy management systems (BEMS). Comparable services are currently used in commercial buildings; managing energy bills by moving demand away from times of high power prices and network usage charges (though not as a means of grid capacity management).

In this section, we focus on the aggregation platform requirements for domestic users, since:

i. Large, commercial buildings with heat pumps are likely to have sophisticated BEMS and temperature control systems (even where these are not aggregator ready; technical, operational and commercial aspects of their demand management are well understood).
ii. Uptake of heat pumps in the non-domestic sector is likely to be modest, and many suitable buildings are already electrically heated.
iii. Peak substation loads coincide with winter demand in most areas of the UK, even before significant electrification of heat; as they are more likely to be cooled, commercial buildings tend to drive summer, rather than winter, peak demand.
iv. Air source (domestic) heat pumps are likely to operate at lower winter CoPs than commercial scale, ground or water source units, and are therefore better candidates for vector switching.

Currently available domestic hybrid gas/electric heat pumps have control systems that can control operation to minimise either the consumer fuel bill, or carbon emissions associated with meeting thermal demand, and either include a third-party control option (i.e. to allow the system to be controlled by an external party), or interface units can be added to allow this function at some additional cost.

As of 2017, control platforms are available from several aggregators and smart energy firms that allow external control of home heating systems, and do not cost significantly more than a smart thermostat – between £250 and £500 installed, (though total costs may be up to £1,000 if additional control interfaces are required). Some firms in this space aim to create sufficient value through network management and price response that they can offer kit to consumers at no upfront cost and no increase in bills.

For comparison, smart meter rollout is scheduled to run between 2016 and 2020; taking 4 years to complete and costing £11 billion - around £500 per household. Smart Metering Equipment Technical Specifications 2 (SMETS2)[22] meters may also allow control of auxiliary circuit connected loads; this feature is intended primarily for EVs, but might be extended to control heat pumps if security of heat supply through an alternative vector (gas) could be guaranteed.

In part due to concerns around security, open protocols are not used for the entirety of appliance control systems; associated vendor lock-in could restrict low-cost access to these devices by external service providers. Despite this, the technical challenges to domestic multi vector heating are relatively minor, and aggregators' marginal service provision costs are expected to be low, though domestic scale DSM is an emerging technology[23]. Structural and commercial barriers are more significant however; particularly as no mechanism exists to share the system value of heat supply flexibility with parties building or renovating new build or existing homes.

[22] Smart Metering Implementation Programme End to End Technical Architecture

[23] Taken from conversations with aggregators.

A **Smart Multi Vector** solution to avoiding heat pump driven peak growth requires the ability to flexibly move heat demand onto the gas network at times, and in locations, of electrical system stress. This will demand a sophisticated control platform, capable of monitoring hundreds of network components and tens-of-thousands of user-demands in real time, to be operational within the next 15 years.

The additional user cost is likely to be between £250 and £500, though as this may disincentivise user uptake, smart energy firms are working to lower the upfront costs.

Smart Storage as a Single Vector Alternative

Rather than supplying peak heat demand through the gas network, a control system like the one described above might intelligently store heat at times of low electrical demand, and discharge at times of grid constraint, thereby both:

i. offsetting network reinforcement and
ii. negating the need for an alternative heat supply vector.

A domestic gas boiler of the scale considered above has an installed cost of between £1,000 and £2,000, multi vector users will also pay:

i. standing charge to connect to the gas network (currently around £100 per year) and
ii. a small fuel premium at high carbon prices (around £10 per year)

above what single vector users might pay; while the former may be difficult to realise from a system perspective (as it would require costless decommissioning of the gas grid) there is some value in pure electric heat supply.

The ability to use heat storage as an upgrade mitigation solution at a substation depends on:

i. the degree of off-peak headroom during the coldest days of winter, and
ii. what the heat pump CoPs are during those times.

To assess a smart single vector approach, we calculate the thermal store capacity – expressed as a multiple of the peak connected hourly thermal demand – required to offset reinforcement at the four HV substations where demand flexing is greatest for a range of hourly hot water tank heat loss coefficients.

Table 11 – Hours of Storage Required to Avoid Substation Reinforcement

Substation	100% Efficient Store[24]	99% Efficient Store	96% Efficient Store
Fossway	29	>72	>72
Kenton	2	2	3
Longbenton	2	2	3
Westerhope	10	>72	>72

The hourly demand levels and total stored heat at connections to Fossway – the substation where smart multi vector gas supply is greatest – is shown below for three days in January 2040 (our model does not resolve the actions of individual buildings; rather we model the total heat demand and store

[24] The efficiency figure indicates the hourly share of heat that is retained by the water tank.

connected to each substation, though true central storage – using a heat network to deliver heat from a dedicated store to individual buildings– is not considered in this Case Study).

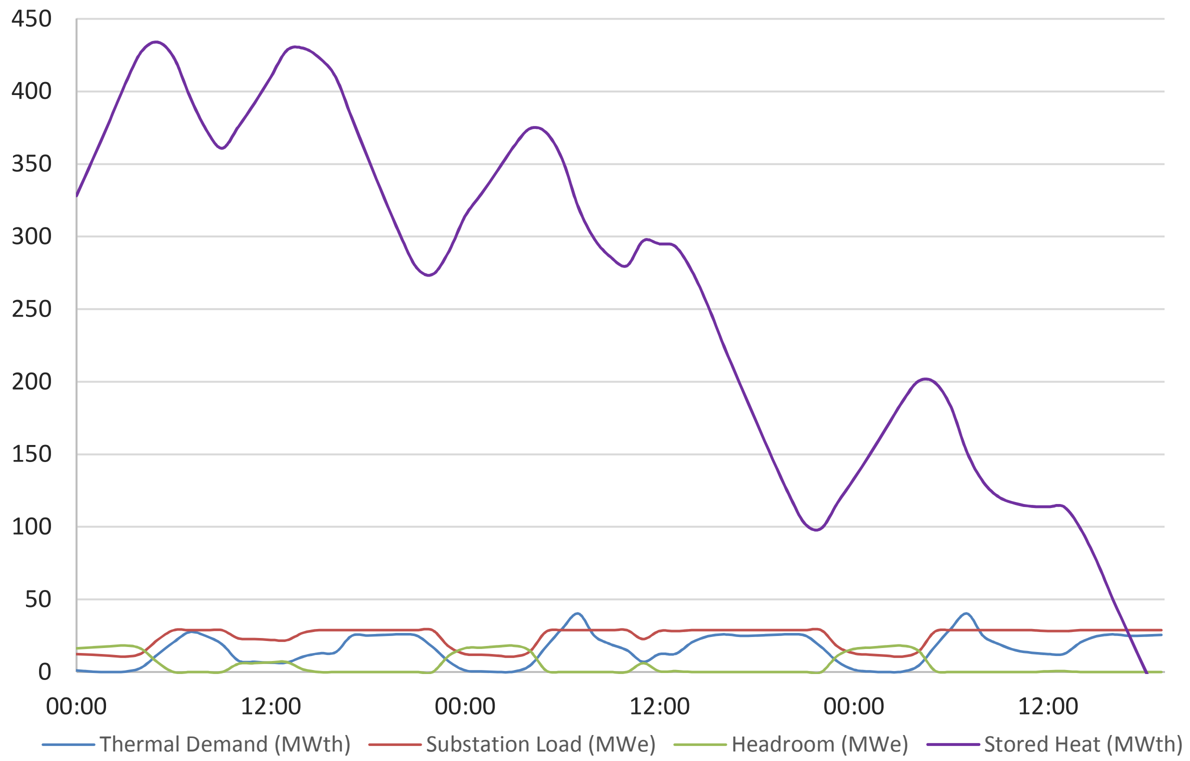


Figure 12 - Single Vector Heat Supply and Headroom at Fossway Substation, 11th - 14th January 2040

By January 2040, single vector demand management requires storage equivalent to over a day's heat pump output at constrained substations - corresponding to a water tank capacity of 500 litres in an average home (at the upper end of domestic water tank sizes), and up to 2,000 litres in larger houses.

However, 2 or 3 hours' storage, as required at Kenton and Longbenton, would be straightforward to install and likely simpler than fuel switching to manage; hot water storage may therefore represent part of the grid demand management solution, particularly if heat pump uptake is combined with substantial improvements to building fabric.

Under unmanaged single vector heat supply, Fossway substation is upgraded twice; suppling heat electrically requires an outlay of between 10 and 20 times the annual environmental margin associated with multi vector supply (see the Running Costs section). Even at such highly constrained substations, partial upgrade to enable smart storage may be more cost effective than multi vector supply. Primary cost drivers for the single and multi vector solutions are given in the table below.

Table 12 – Cost Drivers of Single and Multi Vector DSM Solutions to Constrained Grid

Heat Supply	Network Costs	Infrastructure Cost	Control System Cost	Fuel Costs
Single Vector	Substation upgrade	Storage Tanks	Smart control system, capable of monitoring substation load	All heat supplied by heat pump
Multi Vector	Gas network O&M	Gas Boilers		Over 10% of heat supplied by gas, exposed to carbon price

Storage tank and gas boiler costs include significant installation and connection costs – and are therefore likely to be similar – and the gas network is unlikely to be decommissioned in the single vector case.

Cost differences are therefore dominated by:

i. The substation upgrade required to enable storage as a single vector solution,
ii. The carbon price, and associated increase in multi vector bills (see the section on Fuel Costs).

As this analysis weighs capital and operating costs against one another, the associated timescale and discount rates will be significant.

PCMs

The storage volumes above are determined by:

i. the heat capacity of water, and
ii. heat pump output temperatures

Phase change materials (PCMs) – which store energy as latent heat – and thermochemical heat storage, can offer higher effective heat capacities; their use in active storage technologies might allow a domestic sized unit to store sufficient heat even on highly constrained circuits. These materials are however, currently in the developmental stage and used mainly in passive applications; they are therefore difficult to cost, particularly as they would need to operate within a temperature range suited to heat pump operation. Further, storage based mitigation of grid upgrade at highly constrained substations (e.g. Fossway and Westerhope) requires heat to be stored for several days, and requires an order of magnitude improvement on existing storage heat capacities; it is not clear that advance storage can provide the required energy density at a lower cost than gas network connection.

Intelligent use of hot water tanks does not represent a universal solution to managing peak electrical demand management; it may however constitute a lower cost alternative to multi vector heating on a local basis, depending on winter off-peak demand levels. At constrained substations, the relative costs and benefits of smart storage (potentially with limited grid upgrade) and multi vector heat supply will depend on:

- the degree of substation upgrade required
- carbon prices
- what single vector savings, if any, can be realised in gas network O&M
- the timeframe over which investment returns are calculated.

Advanced thermal storage technologies may allow storage to compete with peak gas use as a solution to the network upgrade required by the large-scale electrification of heat, but they are unlikely to singlehandedly mitigate reinforcement requirements on highly constrained circuits.

We note that this analysis includes a minimum 25% headroom at each substation; as the principal determinant of whether sufficient heat can be generated and stored during off-peak hours, these findings are sensitive to this parameter.

Fuel Costs

By 2050, the average household uses 10.2kWh of heat per annum, the associated heating fuel costs are shown below for three heat supply options; these comprise the wholesale fuel costs, and do not include network connection or standing charges, or any retail margin.

Table 13 –2050 Average Domestic Wholesale Heating Fuel Cost by Heat Supply Option (£/year)

Heat Supply Option	Carbon Price (£/tonne CO_2)		
	0	100	200
Single Vector Heat Pump	276.5	290.5	304.6
Multi Vector[25]	272.8	291.3	309.9
Single Vector Gas	360.3	582.4	804.6

At zero carbon price, heat pumps reduce the average heating bills by 23% compared to remaining on gas heating, and by £500/year at £200/tonne CO_2 (a £200/tonne carbon price implies a 140% margin on the price of gas, and roughly equal costs of unit gas and electricity). Heat pump CoP values are always greater than unity, so multi vector fuel switching drives heat pump customer bills up at high carbon prices, however, since:

i. heat pump CoPs are relatively low at times of multi vector gas supply, at around 1.5
ii. the average wholesale power price at times of smart multi vector gas supply lies in the 95th percentile of the annual price time series, since electricity prices are modelled for a highly-decarbonised future in which heat is substantially electrified.

Multi vector fuel bills are lower than single vector heat pump bills at low carbon prices.

At an average carbon price of £100/tonne, the hybrid heat pump and gas boiler system will have a system payback time of over 10 years (assuming gas network connection charges are common to the multi vector and gas heat supply options). We note that hydrogen and biogas blending may reduce the carbon intensity of gas use.

The effect of falling gas demand on the costs and consumer charging structure of gas network operation is discussed in section 3.1.4.

[25] Average fuel costs are virtually identical for both multi vector implementations.

Network Peak Demand as a Function of Heat Pump Size

In this section, we investigate a less control intensive multi vector solution - limiting peak load growth by capping the electrical demand of each heat pump to some fraction of its hypothetical annual maximum and supplying any required additional heat through the gas network.

The thermal load duration curve - the percentage of the year that a given thermal demand is exceeded - is shown below. Air source heat pump CoP and thermal demand are inversely correlated over the year, so heat pump demand is highest precisely when it is least efficient to run; the electrical duration curve is therefore significantly more sublinear than the thermal curve.

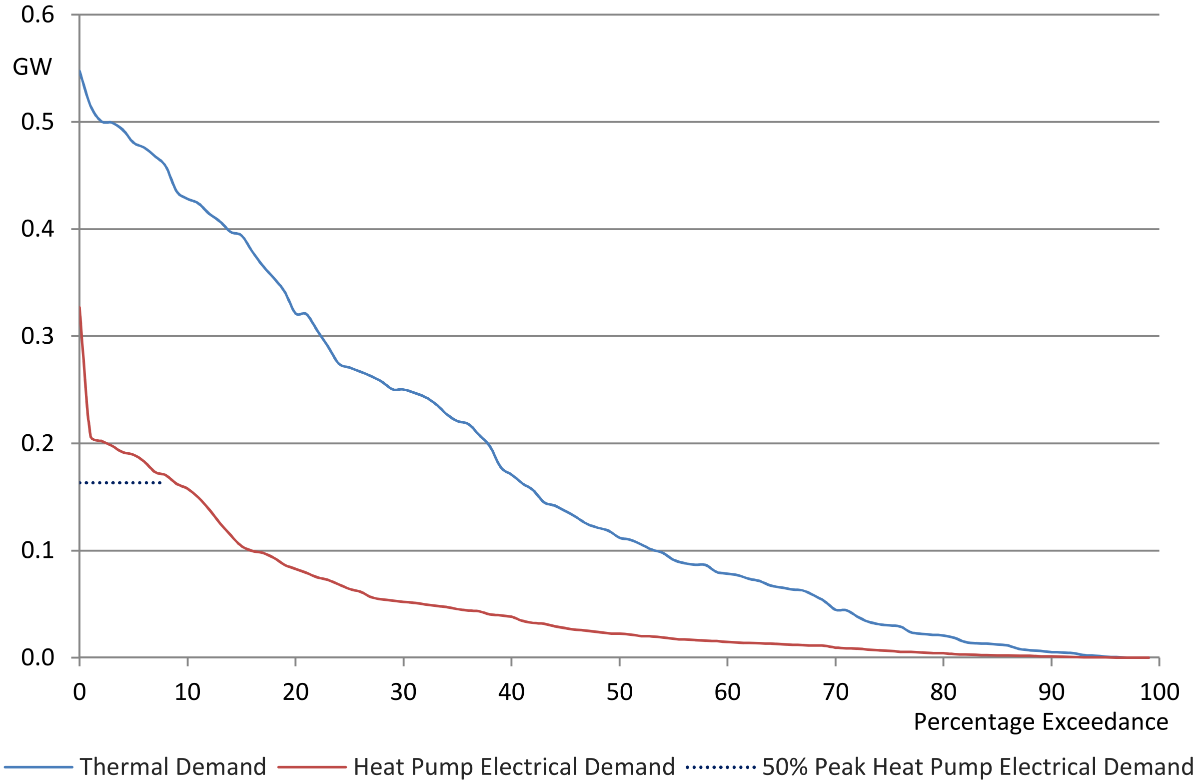


Figure 13 –2050 Total Domestic Thermal and Heat Pump Electrical Demand Duration Curves

75th percentile electrical heat pump demands are exceeded for less than 2% of the year (200 hours), and a heat pump sized to 50% of the maximum electrical demand is sufficient to meet over 90% of the annual thermal demands; the relationship between heat pump size and the fraction of heat supplied electrically is shown below.

Table 14 – Heat Pump Sizing and Associated Electrical Supply Fraction

Heat Pump Peak Size Fraction	Electrical Supply Fraction[26]
20%	62.0%
30%	76.2%
40%	85.8%
50%	93.2%
60%	97.9%
70%	99.2%
80%	99.7%

A 50% multi vector heat pump meets the same fraction of thermal demand on average as the **Smart Multi Vector** solution; with intelligent use of thermal storage, this share could potentially be increased. Scheme grid upgrade and fuel costs are shown below; fuel and emissions costs are calculated as in the previous section.

The **Managed Load Growth** solution reduces the peak thermal demand by 25%; sizing multi vector heat pumps to 70% and 80% of peak demand gives rise to lower and higher grid reinforcement costs than those in the managed single vector solution respectively; scaling heat pump electrical demand and heat output by the same factor have similar effects. The average demand is around 55% of peak, so a flat monthly HP demand profile would be associated with grid reinforcement costs of between £150m and £190m.

Table 15 –Heat Pump Sizing and Associated Network Upgrade Cost

Heat Pump Peak Size Fraction	HV System Costs (£m and number)		LV System Costs (£m and number)		Total Cost (£m)
	Substation Upgrades	Feeder Upgrades	Substation Upgrades	Feeder Upgrades	
20%	0 (0)	0 (0)	1.2 (13)	11.4 (29)	12.60
30%	3 (2)	0 (0)	6.5 (60)	33.8 (96)	43.40
40%	4.6 (3)	2.5 (1)	14.7 (121)	72.4 (188)	94.20
50%	6.1 (4)	6.7 (4)	19.4 (178)	108.7 (324)	140.90
60%	13.2 (8)	7.9 (8)	26.4 (233)	147.1 (481)	194.70
70%	18 (8)	11.1 (9)	32.4 (256)	186.7 (616)	254.30
80%	24.1 (9)	14.3 (13)	37.9 (284)	226.4 (786)	296.50
100%	24.3 (9)	21.8 (25)	50.3 (327)	297 (1036)	393.40

Table 16 – Total Fuel Demands and Costs Associated with Heat Pump Sizing Scenarios

[26] The Electrical Supply Fraction is the share of thermal demand met electrically across multi vector households (those homes connected to the gas networks where a heat pump is installed).

Heat Pump Peak Size Fraction	Electrical Demand (GWh)	Electrical Cost (£m)	Gas Demand (GWh)	Gas Cost (£m)	Carbon Emissions (tonnes)	Carbon Cost (£m)	Total Cost (£m)
20%	244	58.2	272	8.2	59,243	11.8	78.2
30%	301	62.0	157	4.7	34,142	6.8	73.6
40%	339	64.6	91	2.7	19,805	4.0	71.3
50%	369	66.7	43	1.3	9,280	1.9	69.8
60%	387	68.1	13	0.4	2,767	0.6	69.0
70%	392	68.5	4	0.1	952	0.2	68.8
80%	394	68.6	2	0.1	394	0.1	68.8
100%	396	68.7	0	0.0	0	0.0	68.7

For each increase of 10% peak in heat pump size:

i. city grid reinforcement costs rise by around £40m in, while
ii. the annual environmental benefit rises by a decreasing amount; from around £5m to £0.1m.

Total system heat supply costs over 25 years of at a range of heat pump sizes, comprising:

i. the required network upgrade costs
ii. the fuel and emissions premium over totally electrified heat

are shown below:

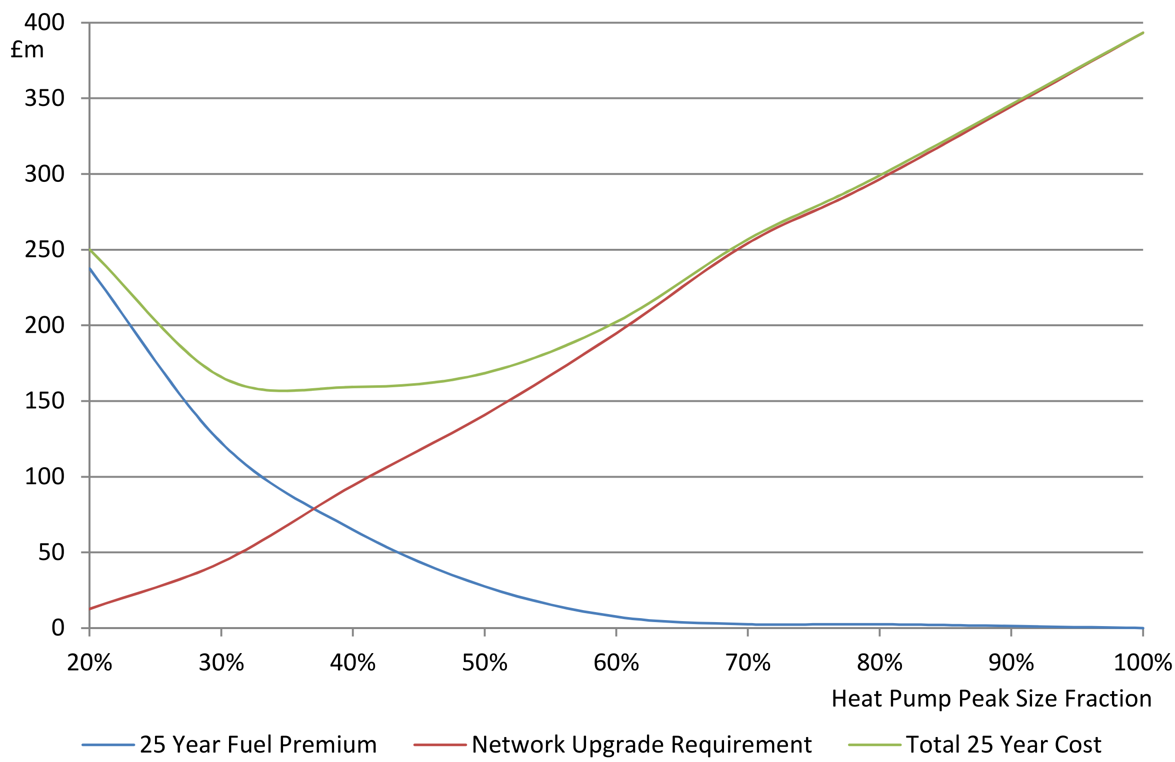


Figure 14 – 25 Year Undiscounted Fuel Premium (at a £200/tonne carbon price) and Grid Reinforcement Costs to 2050 by Heat Pump Size Fraction

We note that:

i. No unit cost reduction is included for smaller heat pumps
ii. A constant carbon price of £200 per tonne is used; these prices are seen only in the BEIS High scenario.

This analysis may therefore underestimate the benefits of under sizing heat pumps and meeting peak thermal using gas.

> Even in a very high carbon price future, unmanaged heat pumps are most economically sized to no more than 50% of the peak load they might draw, with remaining demand met using gas; indeed, this upper bound is likely an overestimate, particularly where intelligent storage can be used, and given non-zero discounting of future costs.

Sensitivities

In this section, we review the effect on our findings of variation in the model assumptions.

Network Capacity Assumption

In the analysis above, we have assumed that all grid components have a minimum 25% headroom above their 2016 peak; this figure is taken from the EPN model, and reflects an operational requirement for redundancy in the network. For future demand management we have included no redundancy requirement; upgrading components only when their full capacity is insufficient to deal with peak demand.

The network upgrade costs under a future 25% headroom requirement across network components are tabulated below. In this case, the savings associated with the **Smart Multi Vector** scenario over each alternative implementation increase, though the reinforcement costs of this scenario also rise, to include nearly £10m of substation upgrades, (as at least 65% of heat must be supplied electrically).

Table 17 –Network Upgrade Costs in Case of a Future 25% Headroom Requirement

Scenario	HV System Costs (£m and number)		LV System Costs (£m and number)		Total Cost (£m)
	Substation Upgrades	Feeder Upgrades	Substation Upgrades	Feeder Upgrades	
High Electrification	34.6 (12)	37.0 (52)	67.3 (387)	435.4 (1537)	574.3
Managed Load Growth	25.4 (10)	25.9 (30)	54.7 (346)	323 (1152)	429.0
Smart Multi Vector	6.7 (6)	9.9 (16)	2.8 (17)	136.5 (453)	156.0
Constrained Heat Pump Demand	18.0 (8)	13.6 (10)	34.3 (284)	204.3 (734)	270.3

> Smart multi vector heat supply saves between £125m (£1,500 per household) and £400m (£4,500 per household) in avoided grid reinforcement costs; this finding is not sensitive to more stringent requirements on network operation. However, the reduction in available headroom increases the value of the smart multi vector solution over the unmanaged alternative - from £25m to over £100m.

Lower HP Uptake Scenarios

In the scenarios above 100,000 heat pumps are installed by 2050. Grid reinforcement costs where a smaller number of heat pumps are installed by this date are shown below for the **High Electrification** and **Smart Multi Vector** scenarios, from 30,000 – scaled from the national BEIS Central HP Uptake Projection - to the reference case total.

Table 18 – High Electrification and Smart Multi Vector Upgrade Costs by 2050 HP uptake totals

Scenario	Total System Upgrade Cost					
2050 HP Uptake	30,000	45,000	60,000	75,000	90,000	100,000
High Electrification (£m)	90.64	123.57	180.38	254.17	323.39	393.40
Smart Multi Vector (£m)	31.99	40.61	65.13	83.70	99.91	113.40
Saving per Multi Vector Household (£)	2,170	2,050	2,130	2,530	2,760	3,110

Due to the network headroom assumption investigated above, per user reinforcement requirements fall as fewer heat pumps are installed. However, clustering of heat pump uptake means particular substations and feeders see a disproportionate share of peak demand increase, so the multi vector savings remain significant.

Per user value of multi vector heat supply falls as fewer heat pumps connect to the network, to just over £2,000 at relatively modest uptake levels; given control system fixed costs, there may be some minimum required level of take up to incentivise a smart multi vector solution.

EV Uptake

The EV uptake scenario presented does not contribute significantly to the overall demand or peak load growth; indeed:

i. Domestic efficiency increases to 2050 more than match the load growth associated with electric vehicles, and
ii. EVs themselves are projected to become increasingly efficient by 2050.

EV charging is also not concentrated in winter and simpler to manage than thermal demand, and therefore does not contribute significantly to instantaneous peaks.

EV demand, particularly for fast DC chargers, may present operational and infrastructure challenges to DNOs, but this analysis suggests these concerns can be largely uncoupled from the network capacity challenge associated with electrifying heat.

Applicability

Our Case Study focusses on the City of Newcastle; in this section, we discuss the applicability of the model analysis and the derived conclusions to the UK energy system.

Network

Structure

The EPN model considers radial networks only. In meshed networks, multiple substations may serve LV networks. This may mitigate peak load growth, particularly where heat pump uptake is clustered in a city district. In the UK however, LV meshed networks are found only in UKPN networks in the south east (these are typically the most constrained) and the Manweb licence area in the North West. The findings of this analysis are therefore likely to be applicable to most UK areas (population density effects are discussed below).

Headroom

In the reference case, a minimum network component headroom of 25% - has been assumed. We have also investigated the effect of more stringent grid requirements; the value of multi vector supply increases as available headroom decreases. Few networks operate at substantially below 75% of their capacity, it is therefore unlikely that undertaking the same analysis for a demographically similar area might return markedly different results.

Single vector smart storage may however represent an alternative to upgrade at more LV than HV substations: substation appliance demand profiles are taken from an EPN model set of 2016 HV substation load profiles. These profiles, and particularly the winter off-peak headroom, affect the potential for storage as a single vector peak shedding solution (they determine whether it is possible to generate and store sufficient heat during periods of low grid use to supply total heat demand). LV substations may see lower off-peak demand – and therefore greater headroom – than the upstream HV substations to which they connect, particularly where LV substations are dominated by domestic demand.

Security of Supply

In this analysis, we determine substation and feeder capacities based on typical annual demand, while gas infrastructure is sized to supply the heat demand of a 1:20 extremal winter. Multi vector heat supply inherits the security of supply, but in e.g. an extremely cold winter between 2040 and 2050, peak single vector heat pump demand might exceed our modelled grid capacity. Under thermal electrification, grid operators might therefore be required to include a significant grid component headroom, at a cost of up to a further £2,000 per household.

CoP and Real World Performance

Model CoP values are unadjusted from manufacturer literature (see appendix 8.2). Field trial data suggests heat pump performance may operate at lower CoPs, due to installation or operational issues. However:

i. Peak network demand is driven by the low end of the CoP range – between 1.1 and 1.6 at ambient temperatures below 5℃ – these are consistent with current operation.
ii. Future domestic heat pumps may be CO_2 based units, which can operate at high flow temperatures at higher CoPs than their R410a or ammonia based counterparts, (CO_2 heat pumps are currently in the initial stages of domestic availability).
iii. Most significantly, peak grid demand is driven by heat pump uptake, so electric heating demand increases until after 2040, by which time heat pump operational performance is expected to meet or exceed 2015 manufacturer data.

Including an optimal operation factor - a linear CoP scaler (below) that converges from unity in 2000 to the manufacturer values in 2050 – does not therefore materially affect the model findings.

$$C'(T,y) = \frac{C(T)-1}{2050-2000}y - \frac{C(T)-1}{2050-2000}2000 + 1$$

Where:

y is the model run year
$C(T)$ is the manufacturer heat pump CoP as a function of air temperature
$C'(T,y)$ is the modified CoP

The design and operation of heat pumps is expected to improve over the next 25 years, and heat pump manufacturers note that reductions of around 15% in flow temperature, and accompanying improvements in CoP are typically possible after a year, given the building heat pump use data. The effect on grid capacity requirement of any decrease in electric heating demand can be taken from the managed single vector or unmanaged multi vector model data.

I&C HP Use

Due to the lack of high quality data, model commercial and industrial thermal demand follows the domestic profile; this likely exaggerates peak heat pump demand. Our analysis includes 5,500 I&C heat pumps, drawing around 7% of the load of their domestic counterparts. However:

- Given their constant year-round CoP, their contribution to the total winter peak is only around 3% of total heat pump demand.
- Around a third of this demand is connected to the HV grid, where reinforcement costs are lower.

It is therefore unlikely that the industrial and commercial profile leads to a significant overestimate in the reinforcement costs.

Population Density

Grid upgrade costs in the EPN model are based on the Urban cost data from the ETI Infrastructure Cost Calculator. Our findings can be applied to less densely populated areas by scaling network reinforcement costs to data for other area types (see appendix 9.2). LV Feeder replacement costs dominate all grid upgrade totals. In sparsely populated areas:

i. material costs of feeder replacement may be larger given the longer networks, but
ii. installation may be cheaper, given lower dig costs.

Rough unit connection costs, taken from the Cost Calculator scalars and by-area housing densities classification from the Committee on Climate Change research on District Heating and Local Approaches to Heat Decarbonisation[27], are shown below. Note that overhead feeder costs are given for

i. underground in urban areas,
ii. overhead in rural areas
iii. an average of the two in suburban areas

Grid upgrade costs per dwelling vary by less than a factor of two; the analysis of this report should therefore be representative for rural areas, though other assumptions, such as the availability of gas network, may not hold.

[27] District heating and localised approaches to decarbonisation, Element Energy and Frontier Economics, 2015

Table 19 – Feeder Upgrade Costs by Population Density

Area Type	Buildings per Hectare	Length distribution network per (km/km^2)	2015 Central New LV Feeder Cost (£/km)	Cost Per Building (£)
Urban	>60	23.9	707,000	<£495
Suburban	30-60	16.6	278,000	£370
Rural	<30	8.1	63,000	>£260

It is unclear how control and monitoring system costs are comprised, though as any solution is likely to be based on an internet connection, marginal connection costs are likely to be independent of population density.

Vector Switching

Homes heated using storage heaters on Economy tariffs may shift some of their demand to peak times as they upgrade to heat pumps. In isolated rural areas, where electrical heat supply dominates, it may not be possible to offset peak electrical growth associated with heat pumps uptake through peak supply over the gas network though over 85% of the UK's homes are on gas.

Given this, the grid upgrade associated with large scale heat pump uptake will be driven largely by the electrification of heat in gas heated homes; our analysis suggests that multi vector heat supply represents a cost-effective means of mitigating the scale of the required upgrade at the national scale.

3.1.4 Gas Networks

Both the single vector and multi vector cases described in this Case Study are consistent with a substantial reduction in domestic sector gas demand. In the single vector case, the high levels of heat pump penetration could be accompanied by decommissioning of parts of the gas network, depending on:

i. How the heat pump users are distributed, and

ii. What heating technologies prevail in non-heat pump homes, in this analysis we assume persistence of gas heating, though in practice alternative solutions such as district heating may also play a significant role, particularly in new build.

For multi vector heat supply however, the entire gas distribution infrastructure remains, operating at much lower utilisation. The implications of these usage pattern changes are considered below;

- on the operation and economics of the gas networks
- on gas consumers' costs.

Where heat is aggressively decarbonised through electrification, other low carbon heating solutions may be rolled out in parallel. In the analysis above we assume that existing heating technologies are maintained unless replaced with a heat pump, 30% of 2016 gas use is therefore an upper bound on gas use, where 60% of homes move to multi vector heat supply.

Gas Distribution Network Costs

We have analysed the make-up of gas distribution network costs to understand how these might be composed out to 2050, and what the associated impact on gas consumers, in the single and multi vector cases, might be.

Gas distribution network (DN) operator charges seek to recover their operating costs, depreciation and return on the regulatory value of their asset base (RAV). Ofgem reviews price control periodically to set the allowed annual revenues for each of the DNs; the table below illustrates how these three cost components contribute to a typical DN's cost base.

Our analysis assumes that Ofgem's regulatory approach is the same in 2050 as it is today, and that:

i. The assumed regulatory asset life of 45 years for new investments[28], and
ii. The level of allowed return

remain unchanged.

We do however consider the composition of the DN fixed costs, and the effect of reduced throughput on that customer standing charges, below.

We have used Northern Gas Network's (NGN's) Revenue = Incentives + Innovation + Outputs (RIIO) business plan together with Ofgem's RIIO financial model as the basis for this work. However, given the very great level of uncertainty associated with many of the DN cost components, this analysis is largely illustrative and should not be taken as a forecast of how NGN or any other DN will manage their networks in the future.

Table 20 NGN 2021 Gas Distribution Network Cost Components

Item	Cost (£m per year)	Cost Share (%)
Opex	144	46%
Depreciation	106	34%
Return	66	21%
Total	**316**	**100%**

Distribution Network Cost Drivers

Repex

A key driver of investment in the distribution networks is the long-running programme to replace iron mains; tier 1 of the iron mains replacement programme (IMRP) should be complete by 2032: this covers the replacement with polyethylene pipe (PE) of all iron mains up to 8" in diameter within 30 metres of a property. Beyond 2032, it is likely that tiers 2 and 3 of the programme will remain, involving the remediation or replacement of mains above 8" based on levels of risk and cost, together with the replacement of some associated domestic services.

At present, the bulk of gas network capital expenditure is on mains (and service) replacement (more than two-thirds in the case of NGN's 2021 figures), approximately 90% of which is tier 1, so there will be a significant investment saving in this area beyond 2032 (although it will take some time before this reduction in investment is fully reflected in DN charges).

Assuming all repex stops after 2032 (this is optimistic, since repex tiers 2 and 3 and some domestic service replacements would continue), but that other capex continues at projected 2021 levels (which may be rather pessimistic), by 2050 depreciation would be at approximately 70%, while asset returns would be approximately 91%, of their 2021 levels. Depreciation plus return would be 79% of the 2021 level.

[28] Regulatory depreciation uses the so-called "sum of digits" approach whereby the level of depreciation of an asset reduces linearly over a 45 year period, hence year 1 has a weighting of 45, year 2 has a weighting of 44 etc.

Opex

No robust work has been published on long-term future distribution network operating costs, particularly for scenarios in which future gas throughput is very low compared with today. However, the following general points should be noted.

i. Although most leaky iron mains would have been replaced, a high proportion of reported escapes are inside the house; these will continue.
ii. There will continue to be leakage from the high diameter iron mains that are still in situ, as well as leakage from PE pipes where these are poorly joined, due to ground conditions etc.

A permanent gas network maintenance workforce will therefore always be required to attend reported escapes promptly.[29]

Geography will be a significant driver of these costs. Significant savings are difficult to make with the current level of service obligations, particularly in sparsely populated areas where sufficient staff numbers are required to maintain geographic coverage. Therefore, to drive down costs, a different approach to the workforce may be required, e.g. through multi skilling. Alternatively, a relaxation of service obligations would allow a reduction in the required workforce, although it is not clear that the HSE would be amenable to this.

Many operating costs have significant fixed components, e.g. system control and head office functions such as IT and finance. Overall while it is difficult to quantify the potential for reductions in manpower as gas throughput drops, reducing running costs by as much as 50% with corresponding reduction in network throughput is unlikely unless there is a commensurate change in service obligations. As such, operating costs are likely to represent a higher fraction of bills in a lower gas throughput future.

More broadly, radical approaches such as mergers or the sharing of back office functions might be considered.

Impact on Revenue Requirements

The following table illustrates the potential reduction in the gas DN operator revenue requirement given a range of assumptions about future operating costs and the projected levels of depreciation and return outlined above.

Table 21 - 2050 DN Operator Revenue Requirements Under Various Network Opex Scenarios

Cost Component	2021 revenue requirement (£m)	2050 revenue requirement with opex at these percentages of the 2021 level (£m)			
		10%	25%	50%	75%
Opex	144	14	36	72	108
Depreciation	106	76	76	76	76
Return	66	60	60	60	60
Total	**316**	**150**	**172**	**208**	**244**
% of 2021	100%	48%	54%	66%	77%

The total DN revenue requirement is relatively insensitive to the future opex assumption, as a material level of depreciation and return remains in 2050 in the above assumption set. A change in grid

[29] The DNs aim to attend uncontrolled gas escapes within one hour and controlled gas escapes within two hours.

regulations might mitigate this by allowing DNs to recover the cost of investments more quickly, leading to lower levels of depreciation and return in the longer term (this would of course be at the shorter term expense of consumers).

Impact on Gas Network Charges

Estimating the impact on gas distribution charges is particularly difficult - it involves dividing one very uncertain number (future revenues) by an even more uncertain number (future gas throughput). The following table illustrates this in broad terms, showing the percentage increase (relative to the projected 2021 level) in the unit cost of gas distribution under a range of assumptions.

Table 22 - 2050 Unit Cost of Gas Distribution as a Multiple of 2021 Unit Cost

DN gas demand (share of 2021 level)	Impact on DN unit cost (as multiple of 2021 figure) with opex at these percentages of 2021 level			
	10%	25%	50%	75%
10%	4.8	5.4	6.6	7.7
20%	2.4	2.6	3.3	3.9
50%	1.0	1.1	1.3	1.5
75%	0.6	0.7	0.9	1.0

The table illustrates how sensitive distribution network unit costs would be to the total DN gas throughput. The extent of heat pump penetration, the amount of gas used by consumers with heat pumps and the scale of non-domestic gas demand are critical factors in determining the future level of gas demand and hence the future level of gas distribution network charges in this scenario.

In the case presented above, gas demand falls to 30% of its 2021 level; this represents a likely upper bound to the gas demand in that year as energy policy that drives this degree of heat pump uptake will almost certainly lead to the deployment of other low carbon heating technology.

As such, gas distribution costs in this scenario are likely to be between 2.5 and 4 times their 2021 levels under the current regulatory framework.

Implications for Charging Structures

Distribution networks charge gas shippers for use of their networks, who in turn pass these costs onto gas suppliers. Gas suppliers recover these costs in their charges to end consumers. Hence, in practice, the impact on gas consumers of increases in the unit cost of gas distribution will depend on how distribution network charges are structured, and how they are passed on to consumers by suppliers.

At present, distribution network charges are very heavily based on capacity (i.e. the maximum daily quantity that the consumer will use) with only approximately 3% based on usage. Suppliers charge domestic consumers on a largely commoditised basis, with a typical standing charge comprising 10% of the average gas bill, and the rest charged based on usage (although zero standing charge tariffs are available).

At 10%, the fixed element of the domestic gas bill does not cover the capacity-related components of today's gas transportation charges (let alone any other fixed costs). As distribution charges become a much more significant part of the total gas bill, suppliers would likely reflect this by changing the structure of their charges to incorporate a higher fixed component. This would seem likely in both the single vector and multi vector scenarios as the supplier's costs would become less variable in either case. Clearly, such a move would have a much more significant impact on the multi vector heat pump user, whose higher fixed charge would be spread over fewer units of gas.

Impacts on Gas Consumers

In the single vector scenario, Newcastle's gas demand is only around 25% of what it is today. If this were reflected throughout the distribution network, it would clearly have a significant impact on consumer gas distribution charges in that area, with distribution network charges three times today's average. Since distribution charges currently comprise an average 17% of domestic gas bills, this would equate to a 40% increase in the average price of delivered gas (assuming all other components are constant[30]).

The wholesale fuel costs for multi vector heat supply are at least 25% less than remaining on gas, even before carbon prices are factored in (see the section on Fuel Costs). It is therefore likely that average fuel bills, and per kWh costs, will not rise appreciably under single or multi vector electrification of gas heated homes. There is however considerable uncertainty around network repayments, and though average fuel bills fall, some customers may see significant increases in their total heating costs.

How much the heat pump users pay for their ability to use the gas network is a key question (given their total gas use is very low, a price structure like that of traditional domestic gas users would contribute very little revenue to the gas network, and would likely not repay the costs of maintaining their connections - in this case, it could reasonably be argued that the non-heat pump users would be subsidising the heat pump users). A model to equitably repay gas network costs must be found, and in particular, a mechanism to cover the costs of multi vector required infrastructure without undermining the consumer case for hybrid heat pumps.

Further:

i. The principal savings of multi vector heat supply accrue to the electrical grid operator in the form of avoided infrastructure upgrades.
ii. No extant policy incentivises engagement of DNOs with gas distributors, heat pump manufacturers and installers, aggregators and other parties required to implement a multi vector heat supply system.

Central oversight, and in particularly a multi vector regulatory framework, may be required incentivise DNOs to realise and share savings with other parties, particularly the gas network operators, given their large decrease in throughput and modest reduction in counterfactual network costs.

Operational Concerns

Throughput

Widespread heat pump uptake will lead to a substantial reduction in overall flow through the gas distribution network, particularly the low-pressure sections to which domestic properties are connected. Under multi vector heating, around 90% of heat demand is supplied electrically, and at each building, the instantaneous gas demand is:

i. Non-zero for no more than 1,000 hours a year.
ii. Significantly less than the gas demand before the installation of the heat pump.

As such, the current gas network should accommodate multi vector throughput levels at all points.

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[30] Clearly, the level of residual gas demand will be a key determinant of the viability of the distribution networks in these time-frames. In October 2016, a report by Frontier Economics was published on gas economics for the Committee on Climate Change to support the 5th Carbon Budget. This contained a recommendation to Ofgem to consider the regulatory approach to stranding risks associated with the gas grid.

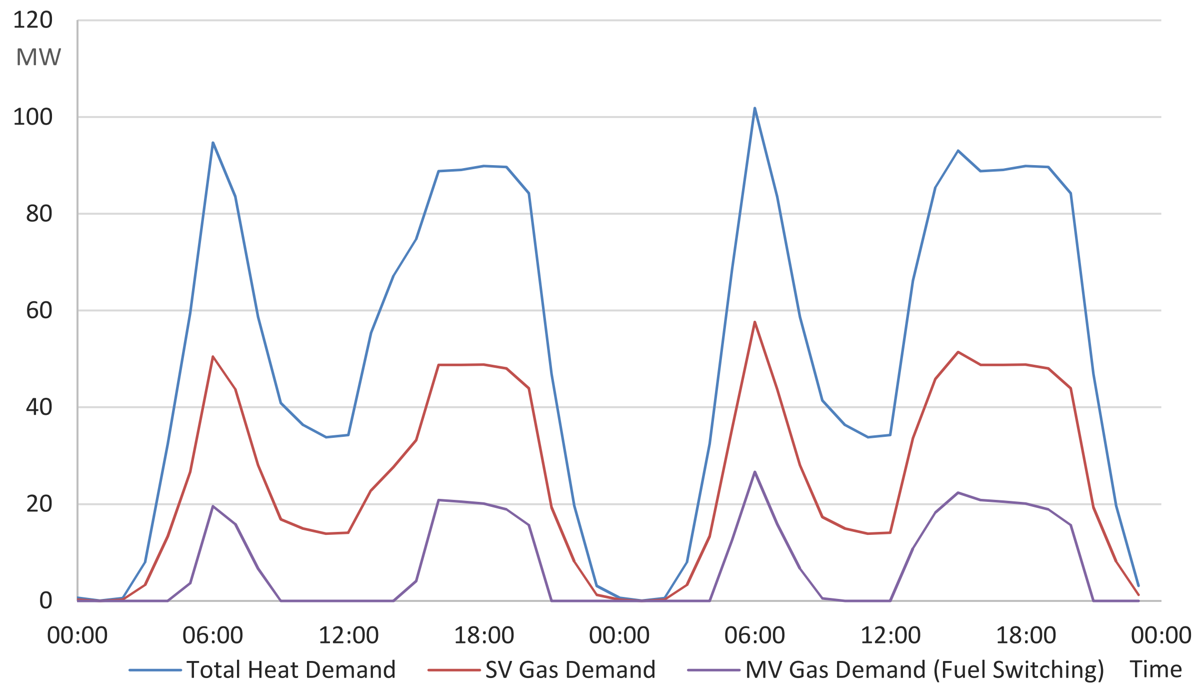

Figure 15 – 48 Hours' 2040 Heat Demand and Share Supplied by SV and MV Gas at Fossway

Pressure Changes

In the **Smart Multi Vector** implementation above, gas demand may spike at large numbers of geographically clustered properties in response to, e.g. a ramp up in electrical demand following the end of a DUoS period, or the simultaneous charging of large numbers of electric vehicles at the transition from a high to a low electrical price half-hour. More generally, the diversification of demand on the gas network may be dramatically reduced as it is tethered to the electrical system.

Following discussions with relevant experts, including National Grid Gas Distribution (NGGD) and project partners Liwacom[31], it is not felt that the ramp rates imposed on the gas distribution network by hourly fuel switching will cause problems, such as unacceptable pressure drops along low pressure pipes. Only in a very extreme case of simultaneous firing of gas appliances was it felt that problems with network pressure would be encountered. Staggering the switch-over from electricity to gas over a period of a few minutes is likely to be sufficient for the gas network to respond (currently the network is designed following a peak 6-minute flow planning criterion). This level of diversity may be naturally retained, or could be ensured by e.g. a time delayed control signal across network areas. Where ramp rates imposed on low pressure networks did cause an issue, NGGD thought it would be possible to resolve using storage at the medium pressure (MP) level. As gas distribution networks have removed gas-holders from the distribution networks, this would need to be new storage capacity, most likely be provided in the form of pipe arrays at the MP level.

That a coordinated ramp-up of gas heating appliances is unlikely to cause a pressure issue is supported by recent modelling, undertaken by Element Energy and Imperial College, into the impact of high uptake of micro-CHP devices on a low pressure gas network, and their operation in a virtual power plant arrangement, which requires highly coordinated turn up and turn down in order to provide services to

[31] Detailed discussions have been held with Liwacom regarding the potential modelling of the gas network under the multi vector conditions described in this Case Study. However, it was felt that the Liwacom model was unlikely to deliver particular insight in this case, as the gas network would have adequate capacity to deal with the multi vector operating mode.

the electricity system (work undertaken in the *Impact of Heat Pump on Gas Networks* NIA project, to be published shortly). This modelling found no pressure drops outside the acceptable operating range, except in cases of extreme combinations of pipeline length and demand density (and even in these cases the pressure deviations were small enough that they could be easily solved by minor adjustments to normal network operation).

Discussions with NGGD did highlight a potential issue due to loss of diversity of gas demand at the very local level, as the low pressure mains in the street will have been sized with a degree of diversity factored in. A drastic loss of diversity at the street level could therefore be an issue, as the main would potentially present a capacity constraint. Again, some degree of switch-over management at this level could resolve this issue.

NTS Linepacking

The operation of the NTS seeks to balance daily inputs to - and outputs from - the system (within an operationally defined tolerance). There is a constant stock of gas within the system which is permitted to rise and fall, to a certain degree, during the gas day in order provide linepack services to the GDNs.

Seasonal throughput variations mean this already happens across wide range of demand levels, including those envisaged in this case study. We therefore do not anticipate any impact on the ability of the NTS to provide such services under multi vector heating - in any case, such impacts would also arise in the single vector scenario. As above, any increase in diurnal storage requirement in the multi vector scenario would likely require a more local storage solution, e.g. through the provision of pipe arrays on the medium pressure system.

3.1.5 Key findings

The modelling presented above gives the following insights into the challenge of aggressively decarbonising heat by 2050 through the widespread deployment of electric heat pumps, and the potential benefits that could be derived from a multi vector energy system.

1. Unmanaged heat pump uptake, where these entirely replace gas boilers, requires grid reinforcement costing around £390m, which equates to £4,400 per house previously using gas to supply thermal demand. A multi vector solution allows much of this cost to be avoided without jeopardising the decarbonisation of domestic heat; heat pumps can to meet over 90% of thermal demands at over 90% of substations by 2050, to supply a total of 92% of the thermal demand of heat pump equipped, gas network connected homes in that year.
2. Although 100,000 heat pumps are installed by 2050 scenario, much of the grid reinforcement is required by 2030, when only 50,000 units have been connected to the grid. As such, a control solution would have to be in place before this date; regulation and commercial arrangements would have to in place to ensure heat pumps installed in the 2020s maintain their boiler and connection to the gas network.

   This is a medium, rather than long term problem; grid reinforcement costs will not be discounted as significantly as if they were not required until the 2040s, and the shape of the heat pump uptake curve will thus affect the NPV of the required upgrade.
3. LV upgrade costs dominate HV costs, and LV feeder upgrade costs dominate those of substations. The smart multi vector scheme can avoid all substation reinforcement costs, but still leads to substantial feeder upgrades. An extension of the scheme in which feeder, as well as substation, capacities are monitored - enabling vector switching to be controlled at the feeder level - is likely to enable additional reinforcement cost savings, worth a further £110m (£1,250 per MV household) over the high electrification scenario, to be captured.
4. In the unmanaged single vector scenario, by 2050 electrical demand outstrips 2016 substation capacity for an average of 6% of the year (550 hours). However, as these hours are collocated temporally in the coldest weeks in winter, domestic hot water tanks cannot, in general, generate and store sufficient heat during periods of lower grid demand to offset the heating demands that occur during peak grid usage periods. It is therefore difficult to substantially electrify domestic heat without substantial grid reinforcement or an alternative supply vector.
5. Due to demographic clustering of the uptake, which is concentrated by householder type, and therefore by city district, particular circuits will see higher load growth than others. Grid reinforcement costs - largely comprising feeder upgrade costs - are therefore significant even in moderate heat pump uptake scenarios, and therefore potentially suitable for multi vector mitigation. Under the BEIS Central heat pump uptake scenario (in which 30,000 heat pumps are installed in Newcastle by 2050), a smart multi vector solution would be worth around £2,000 per multi vector household. This saving represents a solution value lower bound; while at £4,000 per multi vector customer, the total avoided grid costs associated with the 100,000 heat pump uptake scenario represent an upper bound on the control platform and customer incentive cost.
6. The smart multi vector solution requires a high degree of spatial and temporal control; and the ability to remotely monitor and control heat pumps in homes and business attached to particular substations, and potentially feeder lines, in real time. This solution would require significant telecommunications and IT infrastructure, as well the creation of standards around failure modes, service and repair.

7. The main system saving of multi vector heat supply accrues to DNOs who operate their networks as a controlled monopoly. Central oversight or policy may be required to incentivise DNOs to realise the value of the avoided reinforcement, and to share it with the other required parties, most obviously; gas distributors, aggregators and manufacturers of heat pumps.
8. The required grid reinforcement costs mean that even in a high carbon price future, unmanaged air source heat pumps are not viably sized to over 50% of their theoretical maximum electrical demand, even before unit costs are considered. The seasonal variation in CoP produces large electrical demands per unit heat in winter, when thermal demands are highest, resulting in a sub-linear electrical load duration curve; a heat pump sized to half the peak electrical load is sufficient to meet over 90% of the building thermal demand.
9. Since heat pump loads are effectively reduced precisely when they are least efficient, sizing the heat pumps to half their peak electrical demand and using gas to meet peak demands achieves significant grid reinforcement savings with only moderate increases in gas use. The specific network upgrade costs and the corresponding gas use levels are highly dependent on the headroom available on the network.

   Further, although this solution does not require real time grid monitoring, it depends on:

   i. control systems allowing the heat pump and gas boiler to communicate
   ii. control of flow speeds in domestic heating systems
   iii. a combined multi vector heat regulatory framework.

   Creating a pricing or subsidy structure in which customers are incentivised to choose a heat pump sized appropriately to the thermal performance of their homes may also be a complex task.
10. On a system, cost-per-MW-of-heat-supplied basis, reducing the electrical capacity of each heat pump is the most efficient solution - superior solution to flattening the load profile (as this can only achieve a maximum of 45% load shedding), which is superior to installing fewer units (due to clustering). The latter two solutions also require, to increasing extents, the installation of larger units, and therefore associated with higher capital costs.
11. Multi vector benefit increases as available grid headroom decreases, and the value of the smart multi vector implementation - based on real-time monitoring of substation load - increases over the unmonitored alternative. Network and demographic specifics are therefore likely to determine whether a more expensive smart multi vector, or a cheaper unit sizing solution are most cost effective (in the analysis presented here all substations have the same headroom; these are likely to vary significantly).
12. The operational impact on gas networks of the most sophisticated multi vector solution should be minor. However, the business case effects are likely to be significant, with operating costs reducing by less than half, and network throughput falling to at a quarter of 2020 levels by 2050, and to less than 10% at multi vector properties. A substantial, overhaul of the gas network regulations may be required to allow multi vector system operation, including a mechanism under which the grid reinforcement costs are shared with the gas network operators.

3.1.6 Operational and Engineering Implications

Challenges associated with the transition to multi vector operation have been collated through consultation with industry stakeholders and other experts, and are summarised in the table below. Further analysis is provided in the accompanying report *Barriers to Multi Vector Energy Supply.*

	Issue	Impact and Solution / Mitigation
Technical	**Gas demand profile becomes highly seasonal and peaky on diurnal timescales** Multi vector gas boilers are used in a highly-coordinated manner, especially during winter peak morning and evening heating times - this results in high gas demand ramp rates and potential issues with pressure drops along the network.	Given that the network has capacity to meet current, relatively un-diversified peak heating demand, it is expected that the current network would be able to cope with the changed pattern in gas use without significant issues. Element Energy and the Sustainable Gas Institute have recently modelled the impact of highly coordinated dispatch of domestic micro-CHP systems on the low pressure gas network (NIA project on the impact of gas CHP on gas networks, yet to be published[32]) and found few issues with pressure drops across various types of low pressure network, and none that could not be solved by a minor adjustment to network operating pressure. The likelihood that the dispatch of gas heating technology will be highly coordinated depends on the method used to control it; for example, gas heating plant dispatched by direct load control, e.g. by a network operator, could be phased to ensure network pressures remain within an acceptable operating band. This would require monitoring of the gas network low pressure point, and communication between gas and electricity network operators. If control systems to manage fuel switch-over were not in place, and ramp rates on low pressure networks were found to cause network problems, gas storage capacity at the MP level might represent a solution; this would most likely be provided in the form of pipe arrays.
Technical	**DNOs lack of visibility of installation of electric heat pumps on their networks** Currently network operators have little data on which customers have installed heat pumps in their homes; making it difficult to plan network reinforcement or to target demand response strategies to	Network operators are limited to acting in a responsive manner. This limits their ability to plan load growth mitigation strategies or more cost effective reinforcement investments. The roll-out of smart meters should significantly improve network visibility, enabling characteristic heat pump load profiles to be identified. Heat pump installers might also be required to notify the local DNO each time they install a unit.

[32] Gas CHP Impacts Study, 2017, Wales & West Utilities, Northern Gas Networks, http://www.smarternetworks.org/Project.aspx?ProjectID=1705

	proactively address operational issues.	
Technical	**Requirement to ensure that gas is used at the appropriate time from a system perspective** Where householders have both gas and electric heating plant available, it is necessary to ensure that they use gas at the appropriate time from the system perspective, i.e. at times of peak demand of the electricity network.	Failure of householders to reliably switch to gas heating when there is an electricity network peak or shortfall in generation could negate the benefits of the multi vector system, and require investment in the electricity network; users may for example operate their heating systems to minimise bills, without regard to grid loads. Conversely, over-use of the gas heating capability could result in a reduction of the environmental benefits expected from the deployment of electric heat pumps. The required patterns of use of electric and gas heating could be controlled by price signals, direct load control by a network operator or third-party, or by features built-into the end-use appliance. Time-of-use pricing for electricity has been trialled in the UK at several innovation projects (e.g. Tier 2 Low Carbon Network Fund projects, such as Customer-led Network Revolution (CLNR) and Low Carbon London), as well as in various smart meter trials (e.g. the Irish Smart Metering Trials) and as business as usual in some international markets (such as California). UK trials have demonstrated some success in shifting load from peak times – the Low Carbon London dynamic pricing trials achieved responses of up to 150 W/household, with an average response of around 50W/household to a constraint management pricing event. Widespread roll-out of time-of-use pricing in the UK will require smart meter roll-out and the introduction of half-hourly settlement for domestic and small commercial customers. In order to serve as a network management tool, ToU pricing will need to reflect variation in network charges as well as generation costs. Direct load control of heating systems by network operators or third-parties could deliver a more reliable switch from electric to gas heating at the appropriate times. This relies on roll-out of smart meters or alternative gateway devices within homes to establish a home area network (HAN), broad coverage of a wider area communication network (WAN) to enable communication with individual homes and for the electric and gas heating devices (which may be separate or hybrid) to be able to communicate over the HAN. Limited trials of direct load control have been undertaken in the UK to-date, including the CLNR project, which trialled the direct load control of wet appliances with some encouraging results. Key issues concerning consumer acceptance of direct load control, data privacy and security remain unresolved. A third option is to constrain the electrical load that heat pumps impose on the electricity network by limiting heat pump capacity. Product regulations could be used to ensure that heat pumps are only sold

		for use within a bivalent heating system (either as a hybrid system or alongside an existing gas heating technology). The limit on heat pump capacity constrains the impact on the electricity system while ensuring that consumers use alternative heating technology to achieve comfort during peak heating time. This solution may need to be combined with another mechanism, such as time of use pricing, to ensure additional electric heating (e.g. electric convection heaters) is not used to meet peak demands, and to ensure that gas use is limited to the peak periods. Some requirement that users do not interfere with the control of their heating system may be required; user incentivization might comprise a rebate above the “lowest possible” fuel bill, although the associated costs will not be large (see the section on Fuel Bills).
Control	**Domestic HP and Gas boiler cannot be run simultaneously**	Currently operational systems cannot be run at the same time due to the fixed pump speeds and the difference in boiler and heat pump flow and return temperatures. Domestic central heating systems can, in many cases, be run at the 81°C/72°C or 75°C/60°C flow and return temperatures to which they are designed, or (subject to some improvement of building fabric) at a lower heat pump temperature range (perhaps 55°C/30°C). However, at the higher temperature range, a heat pump cannot supply heat. In commercial scale schemes, this problem can be resolved by changing the flow speed and so the return temperature; this is typically not possible in domestic applications. CO_2 heat pumps, described in appendix 5.2, will operate at higher flow temperatures and resolve this problem
Commercial	**Substantial drop in the utilisation of the gas network** As gas use shifts to peak-load-only use in buildings with electric heat pumps, the utilisation of the gas network drops; this will be the case particularly on the low pressure network, to which most homes and small non-domestic buildings are connected. Despite the significant drop in utilisation, the overall capacity of	Gas network operators must recoup the largely fixed network costs over a much reduced volume of transported gas, resulting in a significantly increased network cost component of the overall gas supply cost. Assuming the IMRP is completed as by around 2030 as planned, leakage from the low pressure network should be significantly reduced. Together with the reduced overall demand, and the seasonal nature of gas demand, this may allow network operators to reduce their headcount, and therefore operating costs, to some extent. However, the presence of significant fixed operating costs associated with meeting service level obligations means that the opex will not fall as much as throughput; decreases in gas DN revenue requirements will not reflect their reduction in turnover. Gas transportation charging is likely to increasingly become dominated by the capacity charge rather than commodity charges. The economics of operating the gas networks depend on overall gas consumption, including consumption for power generation, by larger industrial and commercial sites, and potentially for LPG and CPG

	the network to provide peak heat demands needs to be maintained near current levels. The low utilisation of the networks presents economic issues in terms of cost recovery for the network operators.	vehicles. Consumption in these sectors (which is not considered here) may mitigate the economic impact of the fall in consumption as domestic heating is electrified, but an equitable pricing structure which shares investment and O&M costs of the low pressure network across persistence gas boiler and multi vector (peak only gas) users will need to be determined and agreed by the regulator.

3.2 Case 2: Heat Pumps and CHP

3.2.1 Introduction

Context

By 2030, district heating could provide around 42 TWh[33] of domestic heating demand – around 15% of the UK total[34]. These schemes typically use low-carbon plant to meet baseload, and gas boilers to supply peak, demand - this configuration allows the capital-intensive principal plant to be run at a high load factor, and the cheaper, more carbon intensive boilers to be used for only a few hundred hours each year.

Most currently operational district heating schemes in the UK are heat-led gas CHP schemes which create revenue by selling, or offsetting the import costs of, electricity cogenerated in meeting the thermal demand. Around 5.7 GWe of cogeneration is currently installed in the UK[35] - around 10% of peak system demand - so the potential exists for cogeneration to provide significant electrical generation in the medium term.

However, as energy policy begins to reflect an increasing carbon price - driving a rise in gas prices - and the electrical generation fleet decarbonises, gas CHP will become increasingly expensive to run; and heat pumps may displace CHP engines as the primary plant in DH schemes. A CHP engine runs at a thermal efficiency of around 55%, while a hybrid multi vector system, in which a CHP engine generates heat and electricity to run a ground or water source heat pump, will have an overall CoP of between 1.3 and 1.6, and may offer a cost-effective and environmentally beneficial means of integrating cogeneration plant into the energy system[36]. The CHP engine and heat pump might be co-located in the energy centre of a district heating scheme, though more complex configurations, such CHP cogeneration exported to one or more nearby heat pumps, are also investigated in this analysis.

Concurrently electrical wholesale prices are likely to become more volatile as renewable generation increases in share and heating and transport are electrified; multi vector district heating schemes can flex heat generation mode based on the electrical price; powering the heat pump from the grid at times of oversupply, and exporting CHP cogeneration at times of price spikes.

Case Study Aims

This Case Study reviews the potential for gas CHP and electric heat pumps to operate in concert:

i. exporting cogenerated electricity at times of grid stress,
ii. importing grid electricity during low price periods, and
iii. operating independently of the electrical grid at other times.

This analysis identifies future energy system scenarios under which this multi vector system lowers the supply cost of heat, reviews the potential interaction modes, and investigates whether the technical, economic, operational and regulatory requirements for multi vector, grid balancing heat networks are in place.

[33] Research on district heating and local approaches to heat decarbonisation

[34] ECUK Data 2016

[35] BEIS - CHP Focus

[36] A heat pump powered by a network connected CCGT will have a thermal CoP of around 2.0, but higher capital and (due to the network usage premium) fuel costs.

3.2.2 Scenario Definition and Assumptions

The analysis presented here considers a district heating scheme built to serve a mixture of domestic and commercial thermal demand, and the system level and private developer lifetime costs of different plant options at low and high discount rates. Three potential heat supply options are analysed; two single vector configurations - running a gas CHP engine or electric heat pump – and a multi vector solution – in which the CHP and heat pump are operated in tandem. Each scheme also includes a gas boiler to meet peak demand and cover periods of principal plant downtime, sized to maximum scheme demand.

For each configuration, the model optimises hourly operation of that plant - selecting the energy centre output mode that provides the required heat at lowest total cost, for hourly electrical and annual (or quarterly) gas and carbon prices. Given how these prices are calculated in ESME and PLEXOS, we assume that prices accurately reflect their true system costs. Further, we assume that support payments are determined by marginal carbon abatement costs, and do not consider subsidies explicitly.

Network and capital costs are considered on a capacity (per MW) basis; the energy centre and network capital and running costs are determined by the peak demand - the findings of this analysis are applicable to DH schemes of a range of sizes.

Methodology

The Case Study model represents the energy system economically:

i. hourly thermal demand profiles and building level annual totals are combined to calculate a bottom-up hourly scheme demand profile, which is then diversified.
ii. The model then determines the lowest cost dispatch option to meet hourly thermal demands; for each of the single and multi vector cases.

Interpretation of these results then assumes that hourly costs reflect true system value.

Technical and operational considerations are then assessed qualitatively, and the relevance of the analysis to further potential interactions between CHP and heat pumps are discussed.

Table 23 – Energy Centre Plant Options and Dispatch Modes

<table>
<tr><th></th><th>Primary Plant</th><th>Run Mode</th><th>Dispatch Configuration</th><th>Electrical Prices</th></tr>
<tr><td rowspan="2">SV1</td><td rowspan="2">Gas CHP Engine</td><td>CHP</td><td>Run CHP, export electrical cogeneration, meet additional thermal demand using boilers</td><td>High</td></tr>
<tr><td>Boiler Only</td><td>Boiler only</td><td>Low (or negative)</td></tr>
<tr><td rowspan="2">SV2</td><td rowspan="2">Ground Source Heat Pump</td><td>HP</td><td>HP, boiler for additional load</td><td>Low (or negative)</td></tr>
<tr><td>Boiler Only</td><td>Boiler only</td><td>High</td></tr>
<tr><td rowspan="5">MV</td><td rowspan="5">Hybrid System, including both of the above</td><td>CHP</td><td>As SV1 CHP</td><td>Very high</td></tr>
<tr><td rowspan="2">Hybrid</td><td>Run CHP to power HP, meet additional load using gas boilers</td><td>High</td></tr>
<tr><td>Run CHP to power HP, then any spare CHP or HP capacity, then gas boiler[37]</td><td>Low</td></tr>
<tr><td>HP</td><td>As SV2 HP</td><td>Very low</td></tr>
<tr><td>Boiler Only</td><td>Boiler only</td><td>NA</td></tr>
</table>

In the MV hybrid modes:

i. Onsite supply of power from the CHP to the heat pump occurs ‘behind-the-meter’, and
ii. CHP cogeneration costs comprise the gas resource cost only,

so no grid use (pass-through) charges accrue to the operator for on-site power generation and use. This configuration therefore might also represent a CHP supplying a heat pump in a nearby network through a private wire arrangement.

In this analysis, ground and water source heat pumps are considered, so seasonal variation in CoP is minimal. For the multi vector system, the CHP engine and heat pumps are sized so that the HP draws the full electrical output of the CHP engine; with the multi vector CHP engine sized to 40%, and the HP sized to 60%, of their respective single vector equivalents.

Thermal Demand and Diversification

Scheme demand profiles have been derived using space heating load profiles from the Carbon Trust Micro-CHP Field Trials and hot water demand profiles from the Energy Saving Trust report *Measurement of Domestic Hot Water Consumption in Dwellings*. Unlike in the previous Case Study, diversification of thermal demand plays a significant role in reducing peak instantaneous demand, since:

1. The Case Study considers a much larger population than the number of homes connected to an LV substation.
2. Hot water pumping is less sensitive to short term spikes in demand than electrical supply - the scheme itself will have thermal inertia due to the of the significant mass of water.

Peak diversification is explained in appendix 8.4.1.

[37] Note that this case is not considered in our analysis, as we size the heat pump to the CHP electrical output and there is no seasonal variation in CoP.

As daily hot water demand is roughly constant throughout the year, and as hot water comprises a greater portion of thermal demand for new build than existing, this duration curve is flatter than those associated with existing build.

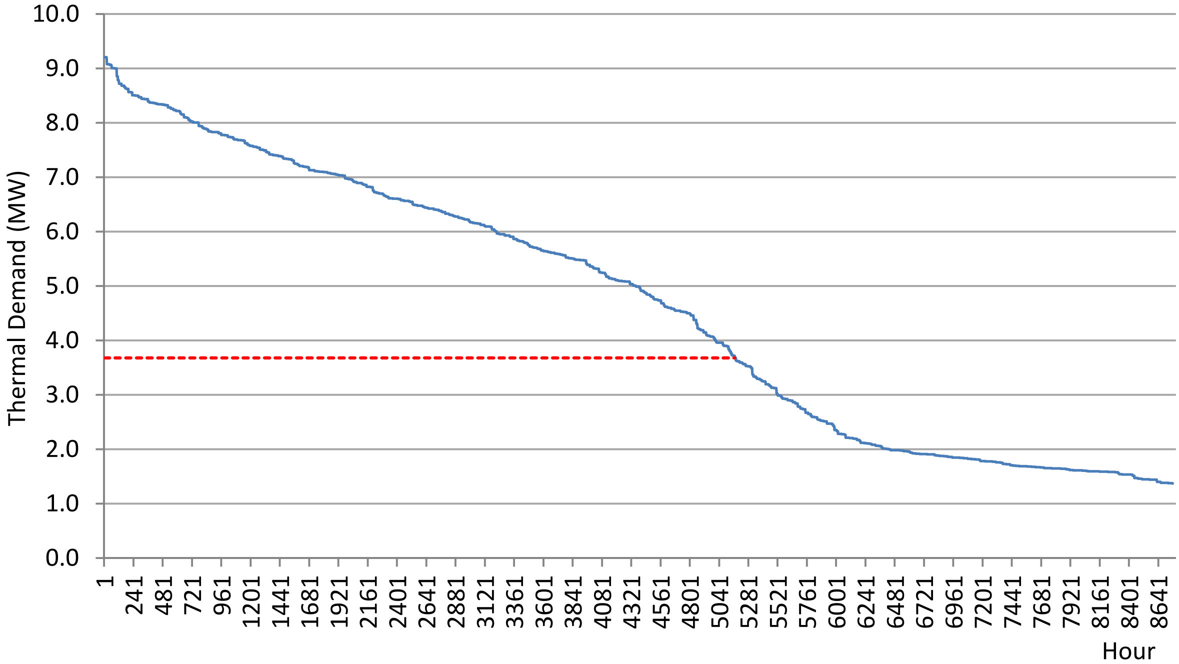

Figure 16 – Thermal Duration Curve with 40% Primary Plant Sizing (in red)

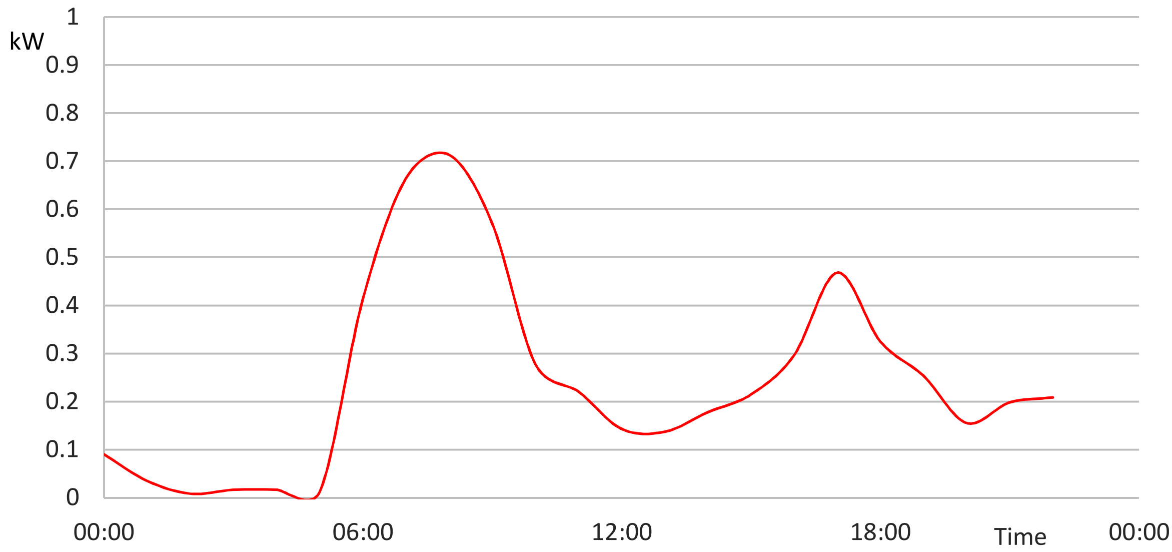

Figure 17- Average Domestic January Diurnal Hot Water Demand Profile

Infrastructure Costs

District heating plant capital and O&M costs are taken from the CCC report *Research on District Heating and Local Approaches to Heat Decarbonisation,* and include a learning curve for heat pumps. Costs are given for a heat pump capable of supplying hot water temperatures (above 60°C) at a CoP of 4 or above. Data and methodology can be found in appendix 5.4.

Heat Network

The network is divided into transmission, distribution and service pipes; pipe diameters are based on empirical maximum flow rates, lengths are based on build densities in existing schemes; these allow the pumping energy and heat loss to be determined. The thermal loss factors of pipes are taken from the literature review described in the CCC report above and verified against manufacturer data.

Fuel Prices

Heat supply optimisation is determined by the quarterly gas and carbon prices and the hourly electrical wholesale prices; these are taken from ESME high and low renewable uptake scenarios. Given the load factors at which peak thermal plant is run in these two scenarios, these correspond to high and low generation price volatility scenarios respectively; the high volatility case is used as the Base Case here.

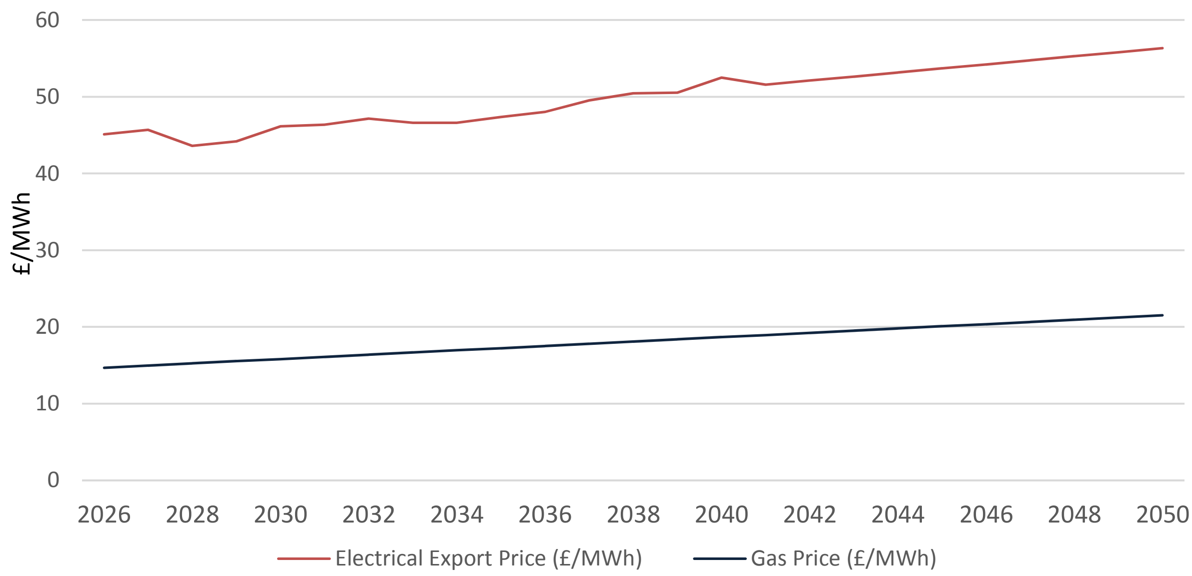

Figure 18- Base Case Electrical and Gas Prices

Electricity Price

Electrical prices from the ESME model are calculated to 2040, and extrapolated to 2050 off-model. PLEXOS, a power market modelling tool that calculates the hourly dispatch of UK generators as well as electricity prices, is then used to create an hourly time series in each case; the 2030 price variation data are shown below for the two cases; these models are explained appendix 5.2.

Table 24 – Standard Deviation of Electrical Generation Price

ESME Power System Scenario	Standard Deviation of Price (£/MWh)
2030 High Renewable Uptake	36.6
2030 Low Renewable Uptake	18.6
2016 Hourly Price Data[38]	31.6

Table 25 - Volatility of Electrical Price

[38] Taken from the N2EX exchange historical data

Total times of high generation Price	2016	2030 High Renewable Uptake	2030 Low Renewable Uptake
Hours above 2 × average	217	131	54
Hours above 4 × average	41	50	28
Hours above 6 ×average	24	31	26
Hours above 8 ×average	14	28	0

The price paid by the DH scheme operator to import electricity includes network usage, balancing, transmission and distribution use of system (TUoS and DUoS) charges and environmental levies. DNOs charge HV network connected consumers through use of system charges, which are levied on electrical consumption depending on time of use (ToU), with the highest charges (red band) applying during peak hours; we assume the structure of these charges reflects the true cost of network use[39][40]. We use system charge data for the WPD East Midlands area; these are higher than most ToU charges, reflecting a relatively congested network – and emphasising the value of diurnal heat supply optimisation. Model data are shown in in appendix 8.7.

Where CHP cogeneration can be used locally, offsetting import, generation value effectively includes these additional grid-use and balancing costs. In such cases the value of CHP will increase significantly, and the CHP load factor will increase as lower electrical export price periods are included[41]. The increased generator value for such private wire schemes is shown schematically below.

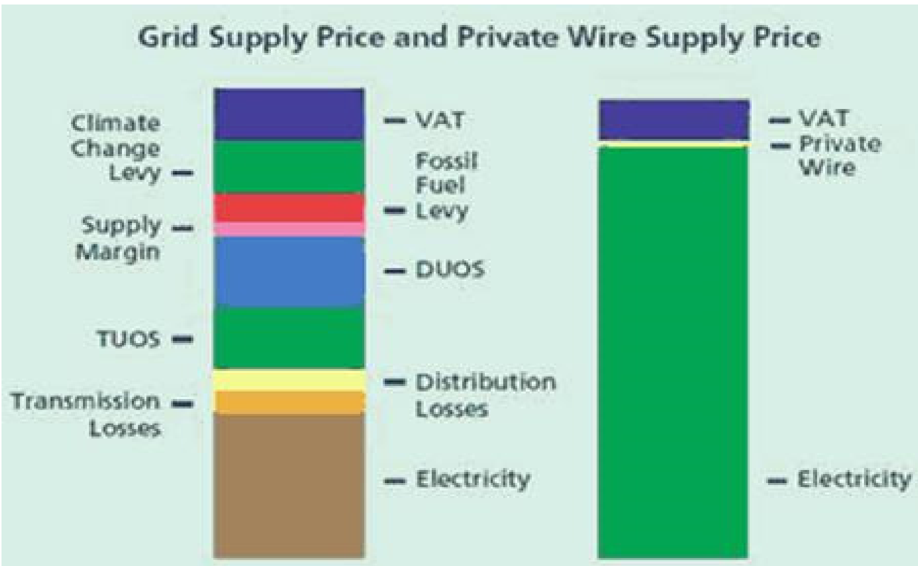

Figure 19 – Relative Grid and Private Wire Supply-Price Components (Link)

[39] TRIAD charges are therefore not included in the model.

[40] As a multi vector DH scheme can run off-grid - powering the heat pump using CHP cogeneration - it draws a lower fraction of its electrical demand from the grid that a heat pump scheme. A multi vector scheme may therefore pay lower total network use charges per MW of connection size; while this may incentivise the development of multi vector DH, it effectively socialises the costs of network use, and is not therefore a whole system benefit.

[41] Generator time of use (GDUoS) revenues are not included however, as intermittent are paid less than non-intermittent generators, and due to their regional variation.

We note that network use charges are on average, roughly equal to the generation costs, and that the average electrical price projections are consistent with the annual prices specified in the CCC report *Research on District Heating and Local Approaches to Heat Decarbonisation*.

Gas Price

ESME gas price scenarios vary from around 30% to 40% of the annual electric price (not including the carbon margin); their trajectories can be seen in appendix 9.

Carbon Price and Grid Intensity

Carbon prices are included from BEIS and CCC projections; those carbon prices for which low carbon primary plant is unviable even at low discount rates are excluded from this analysis.

As its effect on system level DH uptake has previously been investigated, the CCC carbon price forecast is used in the reference case. As the CCC and BEIS electrical generation carbon intensity values are consistent, the BEIS values are used in this Case Study.

Table 26 - Carbon Price Scenarios (£/tonne CO_2)

Year	BEIS Central	BEIS High	CCC
2015	60.0	90.0	46.4
2020	64.0	95.0	55.1
2025	69.0	103.0	65.4
2030	74.0	111.0	77.7
2035	109.0	163.0	141.5
2040	143.0	215.0	205.3
2045	178.0	266.0	269.0
2050	212.0	318.0	332.7

Network Connection Costs

As the DH schemes considered in this analysis use peak gas boilers and import and/or export electricity, all energy centres must be connected to both the gas and electricity networks.

i. The CHP scheme exports electricity only, at a peak export of around 2.5MW
ii. HP scheme imports up to 2MW.
iii. Multi vector DH imports up to 60%, and exports up to of 40%, of the single vector values.

Consumers and generators connecting to the HV network are typically liable for the costs of connecting to a substation, and any upgrades to that substation. The components of these costs are largely fixed, while the gas network connections will be sized to peak gas boiler demand, and are therefore equal across the scenarios. The differences in connection costs to the gas and electrical networks for the single and multi vector energy centre options are therefore not material to this analysis.

Economic Parameters

Total costs are considered over the 25 years following commissioning; as fuel and carbon prices increase during this time, annual costs change over that timescale. The net present value of all project costs, and therefore the breakeven cost of heat, depend on the discount rate. A rate of 3% is used to indicate the societal value, while a higher discount rate - 10% - captures the perspective of private developers and ESCOs.

Thermal Storage

DH schemes can typically store several hours of peak demand worth of heat; allowing:

i. CHP engines to run when electrical prices are high, or
ii. heat pumps to draw power when prices are low,

even when there is little concurrent thermal demand.

Intelligent use of thermal storage is considered in the model, installed at a capital cost of around £1,000/m^3 - around £40,000/MWh. Energy centre plant in this analysis is not sized to over 50% of scheme peak, as thermal demand is highly diversified the principal plant can run at over 90% utilisation throughout the winter, so that storage is deployed primarily in the summer months.

Plant Efficiencies

Heat pump coefficients of performance (COPs) depend upon the source (ground or water) and sink (network flow) temperatures. More thermally efficient new-build can be heated by a lower temperature network, allowing the heat pump to operate at a higher CoP, than when providing higher network flow temperatures required by less efficient existing buildings.

The model DH networks run at a temperature capable of supplying domestic hot water:

- a low temperature network (60℃) suitable new build, and
- a high temperature network (75℃) suitable for existing build stock.

New build will account for 25% of UK build stock by 2030, and 40% by 2050; these buildings represent an opportunity for DH, since:

i. building schemes can be designed for connection to the heat network[42],
ii. securing connection agreements is more straightforward, and
iii. planning policy can incentivise district heating over alternative heating solutions.

Some currently operational or proposed district heating schemes use heat pumps to reclaim heat from gas combustion exhaust, or to preheat water before it is heated to network flow temperatures in a gas boiler or CHP; such low temperature and heat recovery configurations are not modelled in this analysis.

Alternative Heat Supply Options

The economics of heat supply through individual boilers, and through a DH centre using no low-carbon plant are assessed to ensure that the carbon and fuel price scenarios considered are consistent with the uptake of significant district heating; boiler costs are shown in appendix 5.4.

[42] Heat network customer density in this analysis is high, with buildings footprint accounting for 24% of total area, and a distribution pipe length of 23.9km/km2, typical of urban areas. In such areas, the construction of heat networks may be encouraged through building and planning regulations, as well as environmental incentives.

3.2.3 Case Study Analysis

Economic Analysis

We have reviewed the single and multi vector energy centre optimisation for a 2021 DH scheme supplying around 40 GWh annually to 8,000 new build homes and some associated public and commercial buildings for particular choices of the parameters above and determined:

1. The Scheme Cost; the total lifetime expenditure on plant, infrastructure, fuel and O&M at a given discount rate.
2. The associated breakeven price of heat in £/MWh, based on a fixed price over the 25 year project lifetime.
3. Total Scheme Emissions in tonnes CO_2, and the saving relative to a gas-only heat supply option.
4. The Implicit Carbon Price; the Scheme Cost less the total carbon price, divided by the emissions saved.
5. The breakdown by time each DH scheme operates in the modes specified in Table 20, and the corresponding primary plant load factors.

The model also determines the counterfactual cost-of-heat supplied, using in-building gas boilers, and through a gas-boiler-only DH scheme.

Plant Sizing

The effect on lifetime Scheme Cost of sizing principal scheme plant to a fraction of the peak demand is shown below, at a 3% discount rate.

Multi vector and heat pump scheme costs decrease until the principal plant is sized to half the peak demand; carbon prices are sufficient that the low carbon plant capital costs of £1.4m/MWth and 1.9m/MWth respectively are recouped[43].

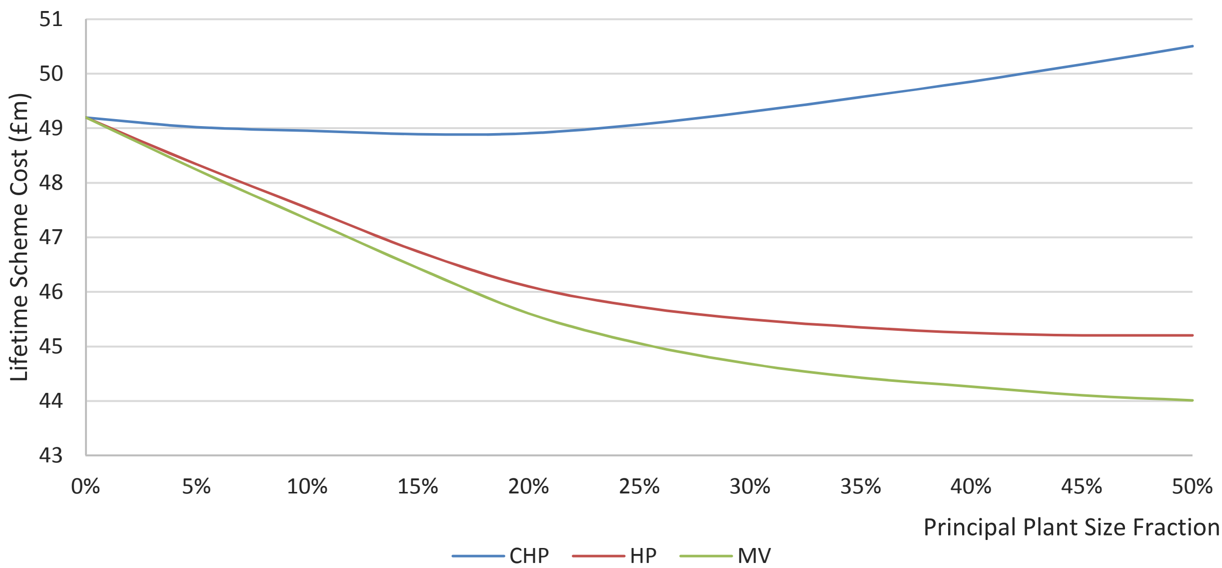

Figure 20 - Effect of Plant Sizing on Total Project Cost at a Discount Rate of 3%

[43]To allow meaningful comparisons, all further analysis is based on principal thermal generation plant sized to 50% of the scheme peak demand, except where otherwise indicated.

Lifetime CHP scheme costs initially fall slowly with increasing thermal size, but increase above 20% peak thermal demand - the additional electrical revenue does not offset the higher upfront capex. Optimum CHP engine size is around 15-20% of peak demand, and not more than 25% of even at zero discount rate. [44]

> The future energy system potential for grid exporting gas CHP appears marginal under these price projections, with multi vector heat supply the lowest cost option.

Total Scheme Cost

The total scheme costs, and the corresponding breakeven price-of-heat, over the 25 year project lifetime are shown below.

At low discount rates, the multi vector configuration provides the lowest cost means of heat supply:

i. the saving over the heat pump scheme - £1.2m – comprises a £1.8m capital cost saving, and an additional £0.6m operational cost, incurred between 2030 and 2042.
ii. Multi vector saving over the CHP scheme is largely comprised of the cost of carbon; the CHP pays around half its (undiscounted) running costs - £33m – as emissions levies; the multi vector scheme pays around £14m.

At higher discount rates increasing carbon prices –starting at £57/tonne and increasing to £269/tonne – are attenuated; the NPV of the emissions levy for CHP or boiler only schemes falls from £550k/year in 2021 to £200k/year by 2045.

A private developer seeking a high rate of return, and taking a short-term view, is therefore likely to prefer to generate all scheme heat in a gas boiler, and install no low carbon thermal plant. Although policy and regulations are unlikely to permit such a heat network operating without low carbon plant, this finding suggests enterprises operating at high hurdle rates will see an incentive to undersize their low carbon heat generators. Although some district heating schemes are built and/or run by local authorities, they may still require projects to deliver rates of return of around 6-8%.

Table 27 – Total Scheme Cost Single and Multi Vector District Heating Schemes (£m)

	DH Primary Plant					
Discount Rate	Local Gas Boilers	Gas Boiler Only	**CHP Only**	**HP Only**	**MV**	**MV Saving[45]**
3%	60.97	49.72	50.51	45.21	44.01	1.20
10%	35.04	29.16	31.68	33.25	31.55	-2.39

[44] The CCC explicitly exclude gas CHP only schemes from their analysis from 2030 onwards due to their carbon intensity.

45 The MV saving indicates how much cheaper the multi vector configuration makes lifetime scheme operation than the cheapest single vector DH configuration, including the gas boiler only option.

Table 28 - 25 Year Price of Heat (£/MWh)

	DH Primary Plant					
Discount Rate	Local Gas Boilers	Gas Boiler Only	**CHP Only**	**HP Only**	**MV**	**MV Saving**[45]
3%	89.4	72.9	74.1	66.3	64.6	1.75
10%	98.4	81.9	89.0	93.4	88.6	-6.72

> Multi vector solution is the lowest cost of the low-carbon heat supply option at both high and low discount rates, though the CCC carbon price projections, if implemented through perfectly efficient policy means, are insufficient to drive the development of low carbon district heat schemes by private developers before 2020.

Plant Use

Both single vector and multi vector schemes optimise their operation based on hourly electrical and quarterly gas prices; so determining the annual run hours for all available heat generation plant. The annual capacity factors of principal plant in the single and multi vector cases are shown below.

The operation of single vector schemes changes little over the 25 year lifetime; increased carbon prices drive heat pump (rather than boiler) use up slightly after 2030, and CHP use falls slightly as median electrical prices fall, and the grid decarbonises – lowering the environmental benefits of CHP.

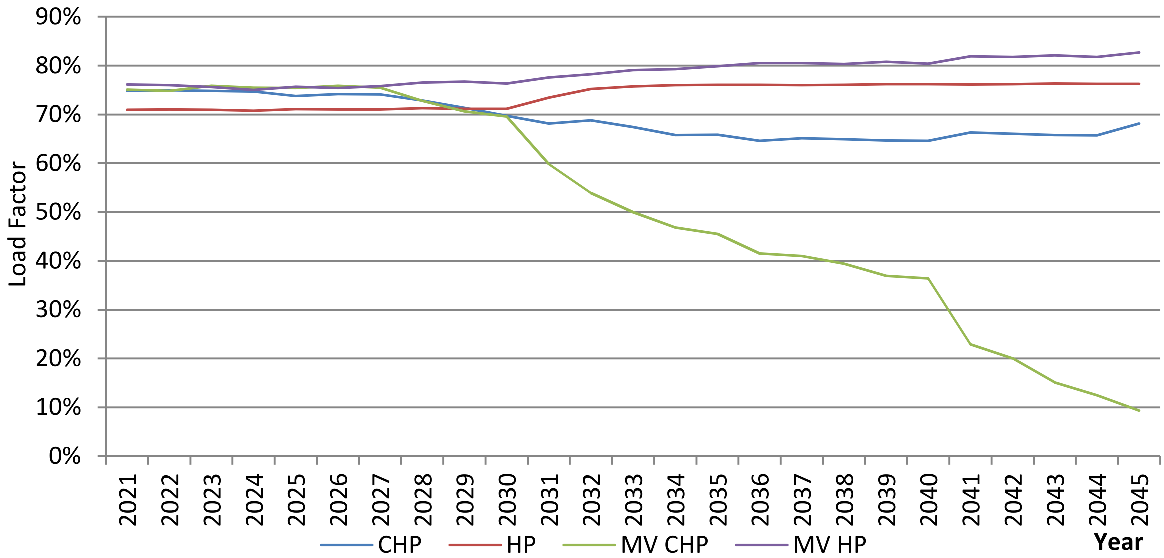

Figure 21 – Single and Multi Vector Load Factors of Principal Plant by Year

Multi vector CHP use falls dramatically as carbon prices increase and the grid decarbonises (making heat pumps more attractive), running less than 10% of 2045, while heat pump load factors remain above 85% for the entire project lifetime. The proportion of run time in each multi vector DH mode defined in Table 20 is shown below.

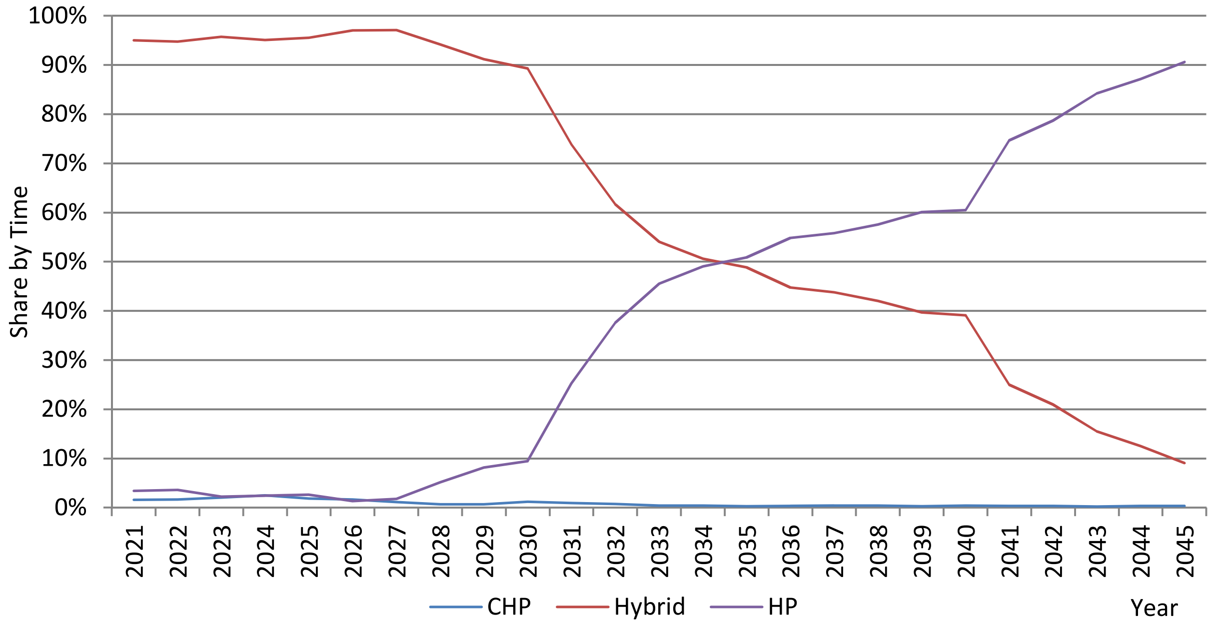

Figure 22 –Multi Vector Heat Supply Mode Share by Time

Hybrid operation is then the lowest cost multi vector heat supply option for over 90% of run hours in the first 10 project years, at carbon prices below £90/tonne. After this the multi vector heat pump begins to run increasingly on grid power.

In hybrid mode, the scheme runs independently of the grid; gas is burned locally in a CHP, the heat is supplied to the network, and cogeneration is used to power a heat pump. The lower power import (HP mode, in Table 19) and upper power export (CHP mode) electrical prices therefore delineate a range in which the multi vector scheme operates on gas only, at an effective CoP of around 1.5. Grid connection costs can be significant; operators may therefore prefer not to connect a multi vector scheme to the electrical network.

Due to the increasing use of grid electricity, the opportunity costs of running exclusively in hybrid mode increase across the scheme lifetime - from £9,000 in 2021 to over £250k in 2045 – and total £0.9m (at a discount rate of 3%); this equates to 2% of the total project lifetime cost, or £0.1m/MWth peak scheme demand. Multi vector grid connection capacity would likely be around 10% peak thermal demand size; where electrical connection capital costs are below £2m/MWe, this is unlikely to be an economic option.

Hybrid multi vector heat supply -using CHP cogeneration to power a heat pump - is the lowest cost heat supply option for over 90% time at carbon prices below £90. Above this it becomes increasingly unviable; multi vector district heat may therefore represent a lower risk, intermediate step in decarbonisation of heat, rather than an end-point.

On highly constrained grid, there may be value in not connecting a multi vector district heating scheme to the grid, running on gas only. The opportunity cost associated with this increases over the project lifetime however, it is therefore more likely that this solution might be used to defer, or reduce the size of, grid connection.

It is apparent from Figure 22 that electrical wholesale prices are rarely sufficiently high for the multi vector scheme to export CHP generation to the grid; the total of CHP mode run hours by year is shown below.

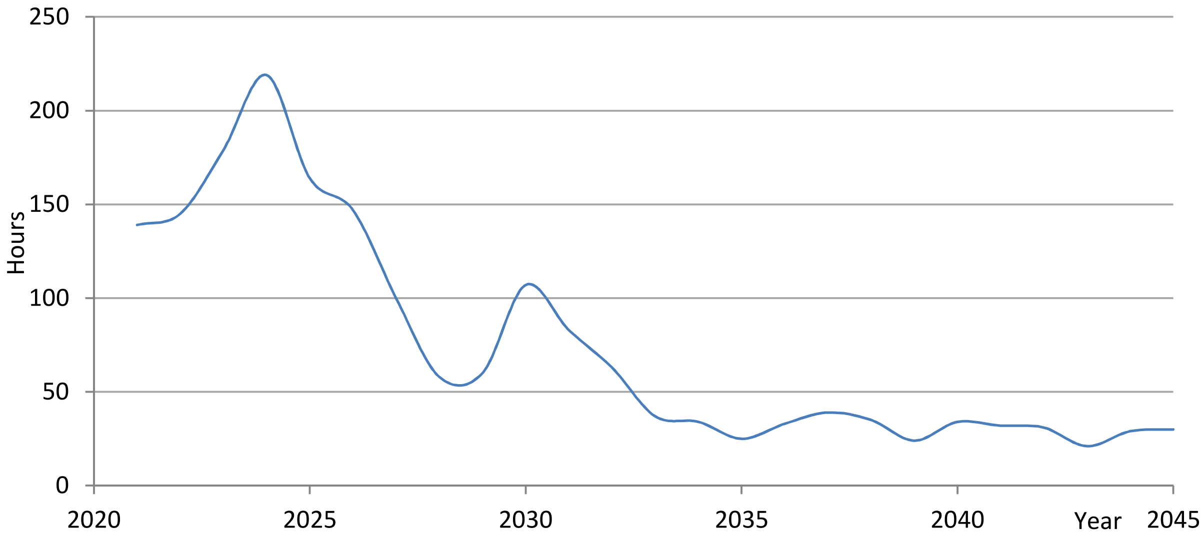

Figure 23 - Multi Vector CHP Cogeneration Export Hours by Year

These totals equate to between 0.25% and 2.5% of the year, corresponding to times of price spikes; despite increasing system level renewable generation - and therefore electrical price volatility - total time in multi vector export mode decreases over the project lifetime, to a steady minimum of around 25 hours of export per year. There may therefore be continuing - if marginal – co-benefit in multi vector schemes providing grid peak shaving and ancillary services to 2050. The minimum electrical price at which CHP exports to the grid is shown below by year single vector and multi vector schemes. We show also the short run and levelised costs of MWhe production for an open cycle gas turbine (OCGT); typically used for intermittent and backup generation.

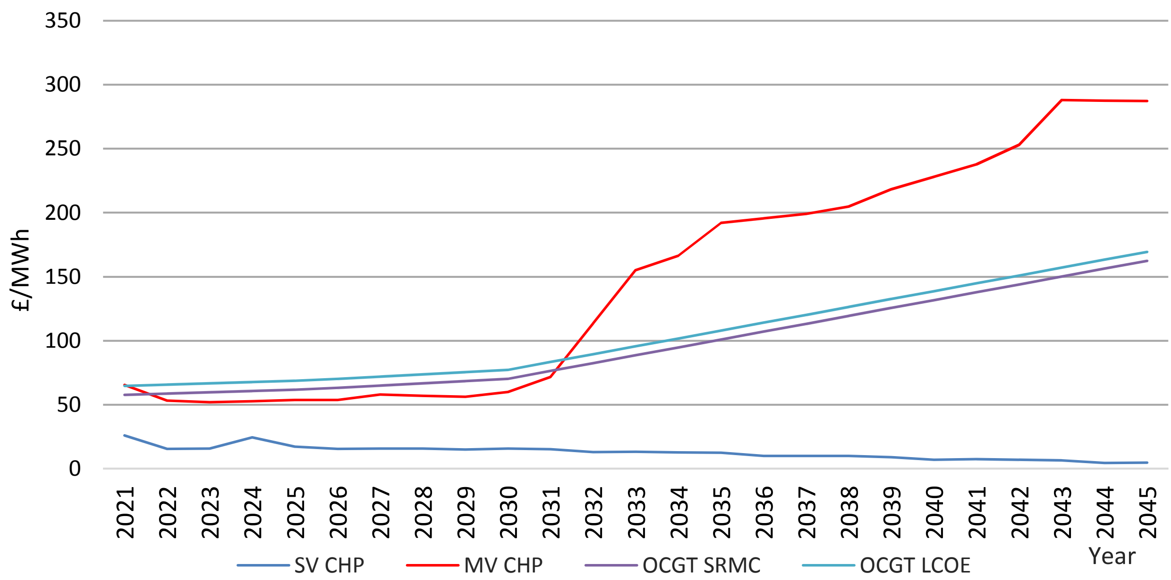

Figure 24 -Minimum CHP Export Prices by Year, and SRMC and LCOE of OCGT

The minimum export price for single vector CHP falls to 2050 - from around £30/MWhe to less than £10/MWhe. The effect of rising carbon prices is to lower export prices - provided CHP cogeneration offsets gas turbine, rather than renewable or nuclear, output (export prices used here are lower bounds, as they include no network operator premium (GDUoS); the effect of higher prices is explored in the Sensitivity section on Cogeneration Value).

Multi vector CHP export prices rise from around 3 to 30 times the corresponding price for single vector CHP, although it represents are a cheaper source of peak generation than both new and existing gas plant until around 2030 - at carbon prices below £90/tonne. Beyond this point, combustion of gas becomes prohibitively expensive due to the low electrical efficiencies of CHP and the decarbonisation of the power grid.

The multi vector gas CHP engine comprises 40% of the total plant, with a thermal capacity of around 20% peak thermal demand and an electrical capacity of half this. Revenues from multi vector CHP cogeneration export - around £25,000 in 2025 and £3,500 in 2040 – total less than 1% of the lifetime scheme cost, and are unlikely to incentivise the choice of multi vector configuration for new district heating schemes. CHP engines may also provide ancillary services to the grid, it is however difficult to assess the future value and associate operating cost increases[46].

Standalone CHP provides a low-cost source of peak shedding, though it may be a more expensive energy system solution overall than a combination of multi vector or heat pump thermal supply and gas turbines. CHP export revenues are insufficient to incentivise multi vector heat network configuration; such heat schemes may however provide services to electrical network operators at around 0.10 kWe/kWth, comprising peak shaving until at least 2030, and potentially ancillary services beyond this.

Implicit Cost of Carbon

The BEIS and CCC Carbon Prices are based on the cost of mitigation, rather than impact[47]; by removing carbon costs from the balance sheet of each scheme and comparing lifetime emissions to those of the gas boiler only scheme, we determine:

i. The total scheme margin paid compared to business-as-usual heat supply, and
ii. The associated emissions avoided.

The ratio of these figures gives the relative social costs of emissions avoidance for each heat supply option; these are tabulated below (network fixed costs are omitted from this calculation, and this metric is not a measure of overall environmental benefit[48]).

Table 29 - Implicit Cost of Carbon

	CHP Only	HP Only	MV
Avoided Carbon Emissions Compared to Gas Only Heat Supply (tCO_2e)	18,147	149,420	107,043
Lifetime Scheme Cost Above Gas Only Heat Supply at 3% Discount Rate (£m)	2.05	9.63	4.40
Emission Saving Cost (£/tonne CO_2e)	113.1	64.9	41.0

[46] Until 2030, multi vector CHP runs over 90% of the time (at a load factor of around 75%); it is therefore likely that at times of potential grid benefit the engine will already be warm, and therefore able to provide short response-time services. After 2030, it may be necessary to keep the CHP in "hot standby" mode, which will increase scheme operational and fuel costs.

[47] The CCC costs are modelled to meet the emissions targets in the Fifth Carbon Budget.

[48]Further, since plant costs are calculated on a per MWth basis the implicit cost of carbon increases as low carbon plant increases in size and runs at a lower load factor.

The multi vector emissions saving cost is less than two-thirds of the heat pump cost; and less than 40% of the CHP only cost (even when the CHP cogeneration is assumed to offset gas fired, rather than grid average, electrical generation).

> While this is not a universal measure of environmental performance, the multi vector configuration appears to most cheaply decarbonise the supply of heat by a substantial margin; rather than decarbonising 1 MWth of DH through the installation of a heat pump, a lower cost environmental policy might decarbonise 2 MWth of DH through multi vector supply.

Sensitivities

Multi vector supply marginally reduces the lifetime costs of heat supply; in this section we review the effect of model assumptions on the multi vector benefit to determine the effect of model parameters on these findings.

Carbon Prices

Substantial take up of district heating as a domestic heating solution will require significant future environmental policy, and particularly carbon prices. In the analysis below, we review the effect of a range of central and high carbon price scenarios on the economics of multi vector heat supply (carbon price scenarios in which low carbon plant does worse than a central gas boiler only scheme are excluded from this analysis).

Heat supply costs by year are shown below for:

i. CHP grid export
ii. HP grid import, and
iii. Multi vector hybrid operation mode

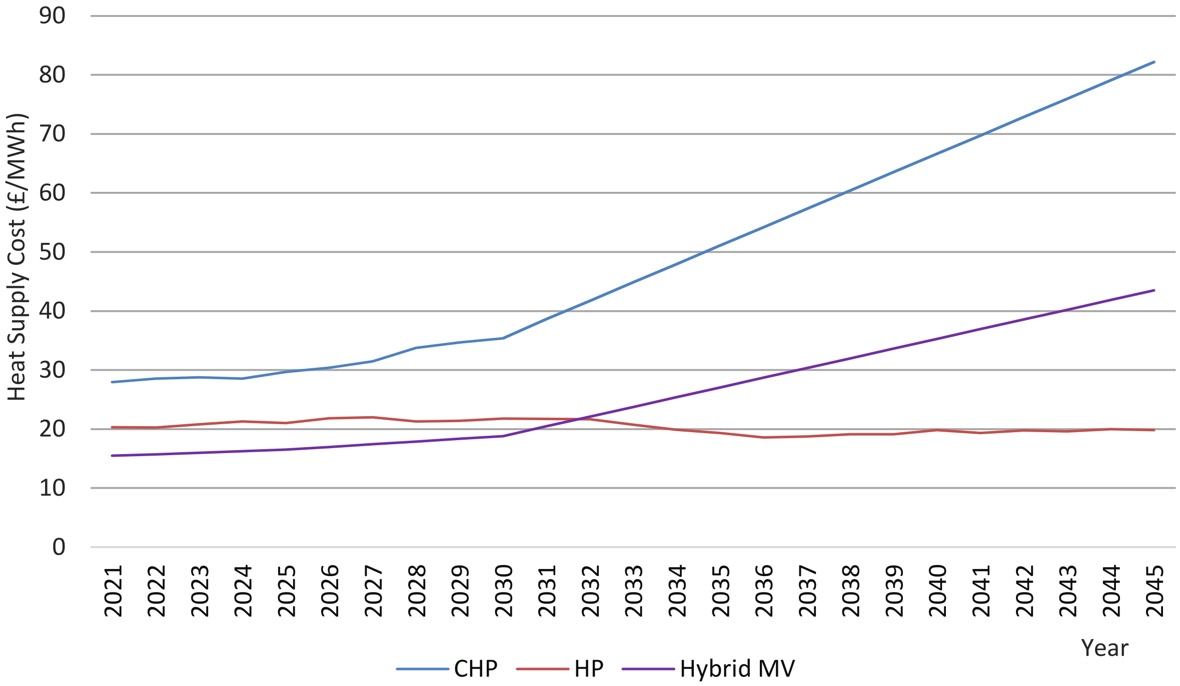

Figure 25 – CHP Export, HP and Hybrid Multi Vector Heat Supply Costs by Year

In the analysis above, between 2020 and 2045:

i. Carbon prices rise from £65/tonne to £270/tonne, corresponding to a levy of 75% and 250% of the unit price of gas respectively.
ii. The carbon intensity of grid electricity falls by 85%; the environmental levy on electricity falls by half over the same period.

From figure 22, a multi vector scheme operates:

i. in hybrid mode for 90% of run hours in 2030, with carbon prices at £90/tonne,
ii. in hybrid mode less than 50% of run hours in 2034, with prices at £150/tonne, and
iii. in hybrid mode less than 10% of the time by 2045, with prices at £270/tonne.

Gas and power prices rise moderately and linearly over the same time scale (see Figure 18); carbon prices therefore represent the primary macroeconomic driver of scheme operation. Scheme operation under the carbon price scenarios given in Table 26 are explored below.

Under the BEIS Central Scenario, the scheme operates in hybrid mode for around half the time in the last 10 years of operation, while under the BEIS High Carbon Price Scenario the heat pump runs on grid electricity for a substantial portion of the first ten project years.

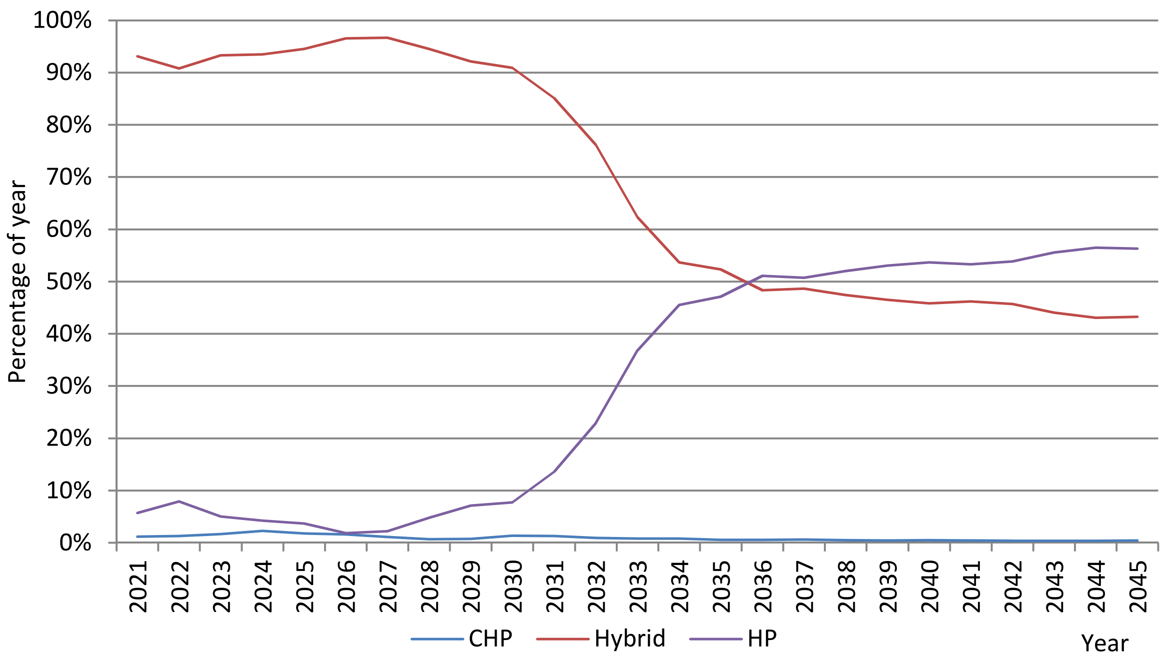

Figure 26 -–Multi Vector Heat Supply Mode Share by Time, BEIS Central Carbon Price Scenario

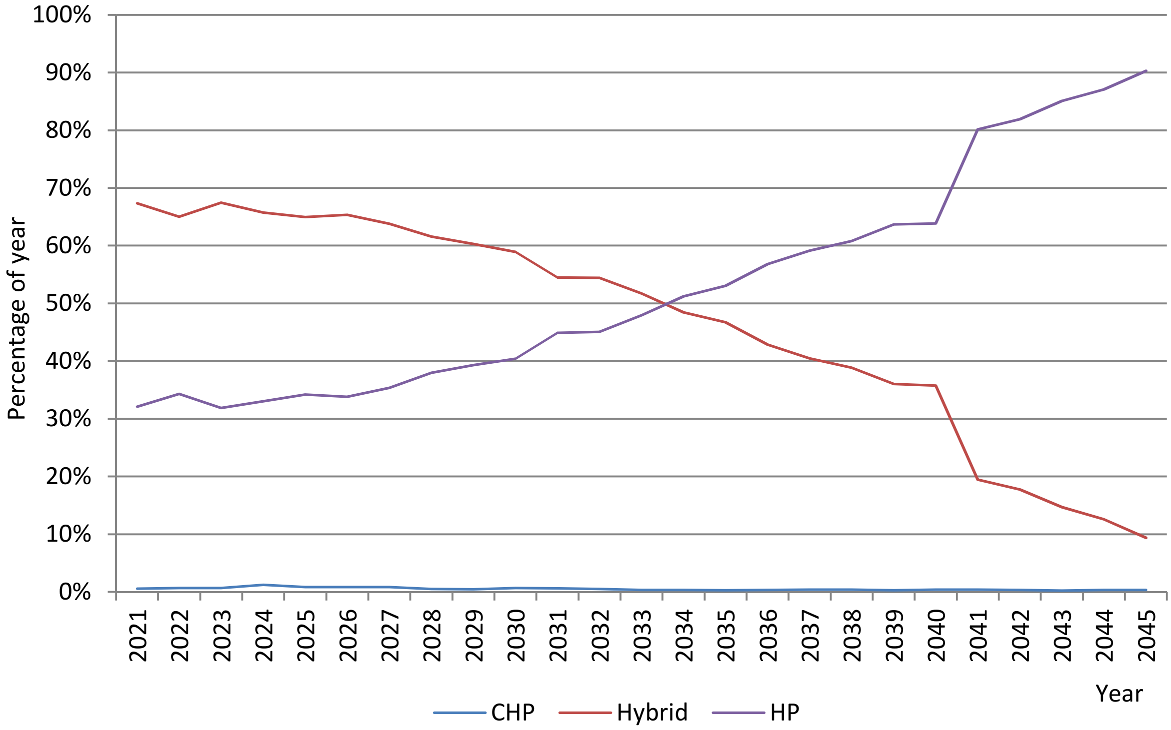

Figure 27 -–Multi Vector Heat Supply Mode Share by Time, BEIS High Carbon Price Scenario

The lifetime scheme costs are shown below; multi vector savings in the Base Case and under the BEIS Central carbon price scenarios are similar – around 2.7% of lifetime scheme costs. Under the High initial carbon price set the multi vector hybrid mode (and therefore the CHP engine) is used less than 70% of the time this option value is consequently reduced.

Table 30- Effect of Carbon Price on Total Scheme Costs (£m) at a 3% Discount Rate

	DH Primary Plant					
Carbon Price Scenario	**Local Gas Boilers**	**Gas Boiler Only**	**CHP Only**	**HP Only**	**MV**	**MV Saving**
CCC (Base Case)	60.97	49.72	50.51	45.21	44.01	1.20
BEIS Central	57.64	46.15	47.15	44.35	43.22	1.13
BEIS High	64.86	53.89	54.37	46.33	45.86	0.47

Table 31 - Price of Heat (£/MWh) under a Range of Carbon Price Scenarios at a 3% Discount Rate

	DH Primary Plant					
Price Volatility Scenario	**Local Gas Boilers**	**Gas Boiler Only**	**CHP Only**	**HP Only**	**MV**	**MV Saving**
CCC (Base Case)	89.4	72.9	74.1	66.3	64.6	1.75
BEIS Central	84.55	67.70	69.16	65.05	63.40	1.65
BEIS High	95.14	79.05	79.76	67.96	67.28	0.68

Carbon price is the main driver of multi vector scheme operation, and the hybrid mode is used decreasingly at prices of over £90/tonne. Benefit of the multi vector arrangement is driven by hybrid operation – independent of the electrical grid; as this becomes increasingly expensive, the benefit falls.

We note that:

i. ESME electrical prices include their carbon costs, though the yearly ESME carbon abatement costs are significantly lower than the model prices, which are used to adjust gas costs.
ii. Annual average grid carbon intensity is reflected in the model; it does not vary hourly to reflect generation plant use. At times of peak demand - when contingency plant is used - the carbon intensity of unit generation is likely to be above mean value.

This analysis therefore likely underestimates the carbon intensity of generation, and the associated system cost, during periods of peak demand. The total system cost of grid powered heat pump operation may therefore also be underestimated.

Electrical Price Volatility

The single vector CHP and heat pump schemes export and import electricity, and are most economically run at times of high and low electrical prices respectively. Multi vector scheme provides greater insulation against price volatility, low price volatility – a more stable market - therefore decreases multi vector benefit; to the extent examined below.

Breakdown of multi vector run mode time under less volatile prices, corresponding to Figure 22, is shown below. Comparing these two figures, it is apparent that under a less volatile price forecast, the multi vector scheme operates in hybrid mode for an even larger share of the first 10 years of the project lifetime.

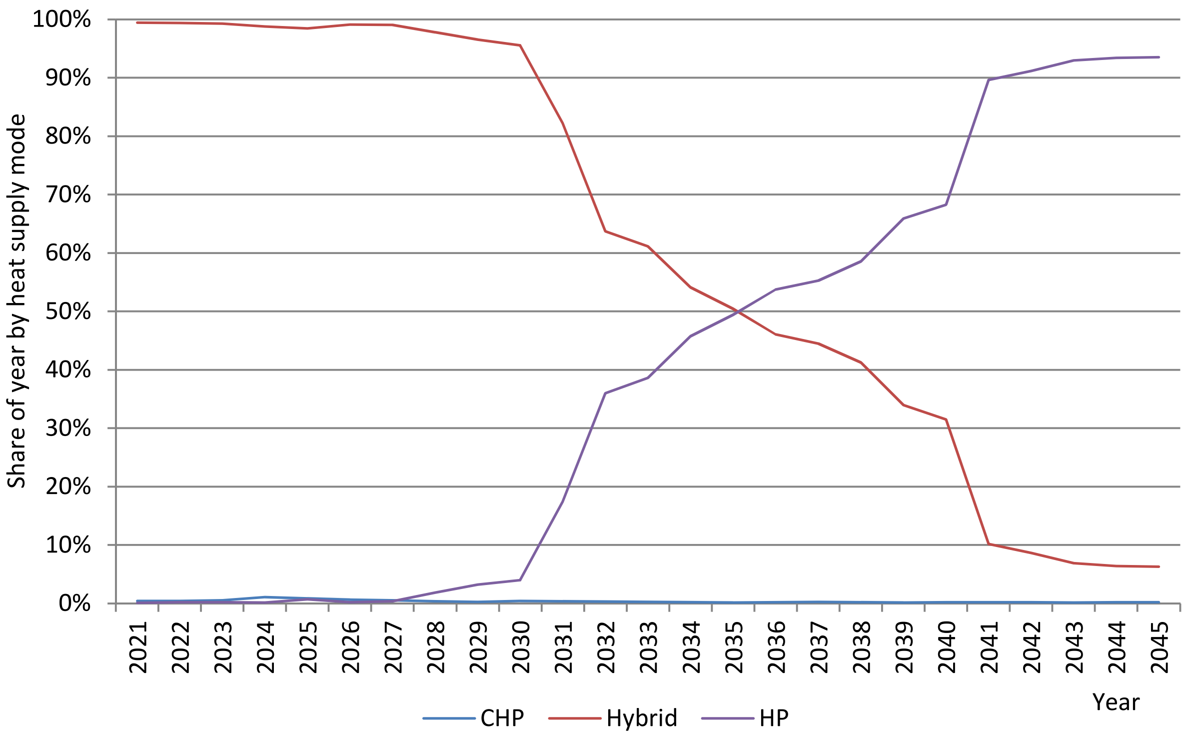

Figure 28 -–Multi Vector Heat Supply Mode Share by Time, Low Electrical Price Volatility

The multi vector scheme is insulated against both upward and downward movement in the electrical price, the multi vector saving therefore falls by 10% under less volatile electrical prices.

Under lower price volatility, the multi vector scheme operates in hybrid mode, independently of the grid, for a greater share of the first 10 project years than in the Base Case.

District heat operators might also hedge against electrical price movement using a power purchase agreement (PPA); below we calculate heat supply costs where electrical and gas costs are fixed to their annual averages; in which case the multi vector saving falls by almost 40%.

Table 32 - Total Scheme Costs (£m) Low Price Volatility Scenarios (3% Discount Rate)

	DH Primary Plant					
Price Volatility Scenario	**Local Gas Boilers**	**Gas Boiler Only**	**CHP Only**	**HP Only**	**MV**	**MV Saving**
Annual Averages	60.97	49.72	59.39	53.67	52.91	0.76
Low	60.97	49.72	51.06	45.35	44.26	1.09
High (Base Case)	60.97	49.72	50.51	45.21	44.01	1.20

Table 33 - Price of Heat (£/MWh) Low Price Volatility Scenarios (3% Discount Rate)

	DH Primary Plant					
Price Volatility Scenario	**Local Gas Boilers**	**Gas Boiler Only**	**CHP Only**	**HP Only**	**MV**	**MV Saving**
Annual Averages	89.4	72.9	87.12	78.73	77.62	1.11
Low	89.4	72.9	74.9	66.5	64.9	1.61
High (Base Case)	89.4	72.9	74.1	66.3	64.6	1.75

Diurnal and seasonal price volatility has little effect on the multi vector benefit, which continues to represent the lowest cost low carbon district heat supply option - a lower bound on this saving as prices vary less is around 60% of the reference case value.

Cogeneration

Supply Point

CHP generation can be exported to the grid, or used to offset local demand; in the former case the value to the generator comprises only the wholesale generation price, in the latter, the network usage charge effectively also accrues to the CHP operator. In this section, we examine the potential for local supply through e.g. private wire networks to increase CHP cogeneration value; this analysis presents an upper bound on this value, since:

i. We assume local consumers use all cogeneration
ii. Private network capital and operational costs are not considered (though if (i) holds the CHP need not connect to the grid, and some of these may be offset).

Annual scheme running costs are shown below at equal power export and import prices.

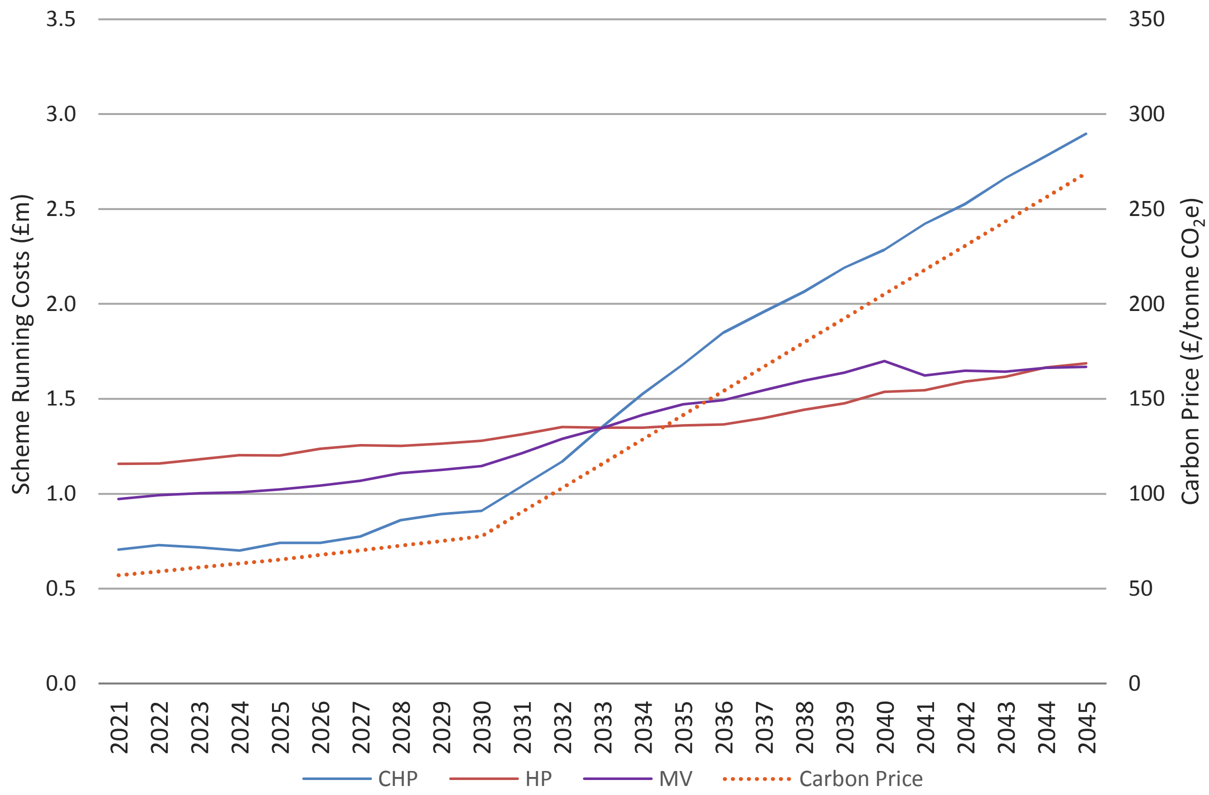

Figure 29 – Annual Scheme Running Costs and Carbon Price, CHP Generation Used Locally

Increased cogeneration revenue makes single vector CHP the cheapest supply option until 2033. After this, the carbon cost of gas generation, and the accompanying decarbonisation of the grid, make CHP operation increasingly unviable.

Plant load factors - corresponding to Figure 21 – are shown below; higher cogeneration value drives increased early multi vector CHP export. Overall trends remain similar to the reference case.

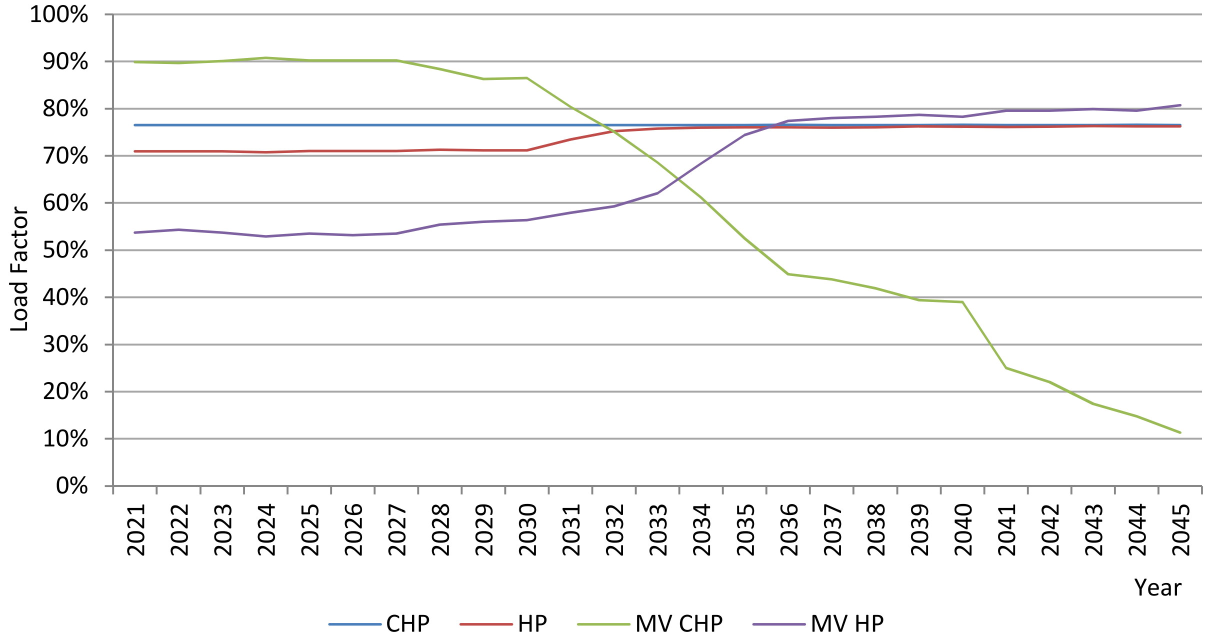

Figure 30 – Single and Multi Vector Load Factors under Local Supply of Cogeneration

Multi vector mode time shares are-shown below, again they are similar to the reference case, system evolution is qualitatively unchanged:

i. There is significant CHP export, but only in the first 15 project years.
ii. Hybrid mode is most common until 2035, after which heat pump use overtakes it.

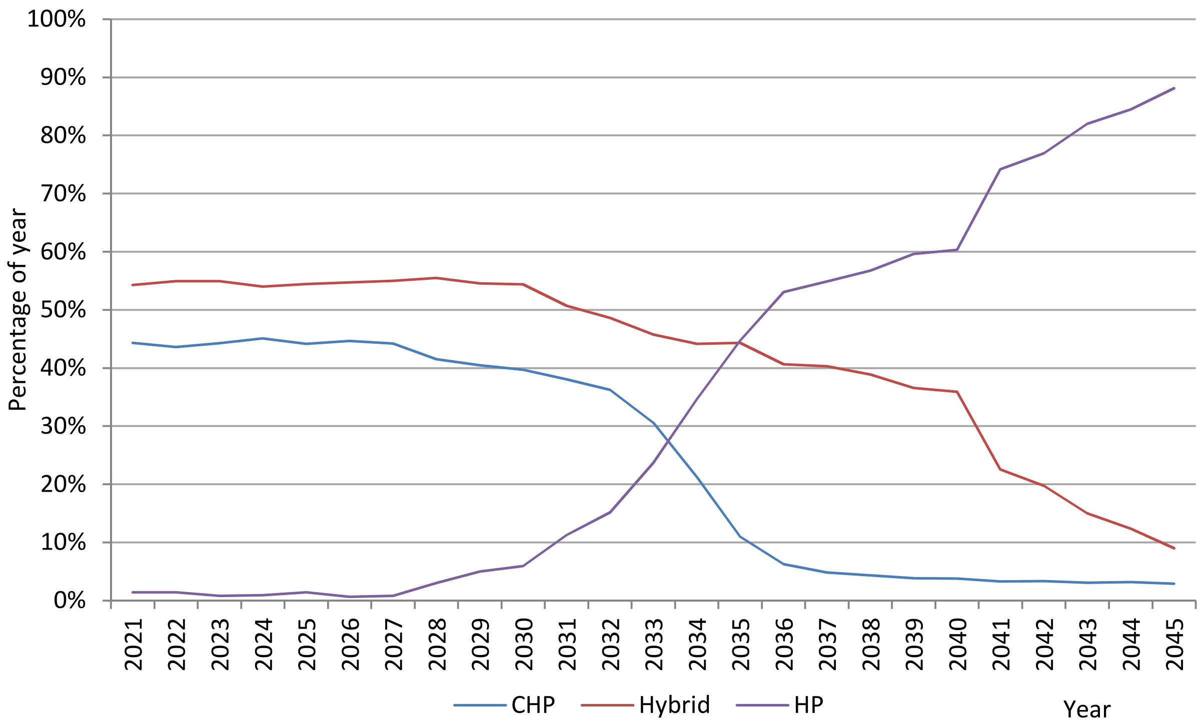

Figure 31 - Multi Vector Heat Supply Mode Share by Time, Local Supply of Cogeneration

Scheme lifetime costs, and additional project revenues, are shown below:

i. The value to the single vector CHP scheme is around £10m over the project lifetime, the multi vector benefit is only £1.5m; multi vector operation is therefore not the lowest cost heat supply option.
ii. The CHP-only scheme is the most attractive in the medium term; although its lifetime running costs are higher, its capital costs are lower.

Table 34- Effect of Cogeneration Value on Total Scheme Costs (£m) at a 3% Discount Rate

	DH Primary Plant					
CHP Export Scenario	**Local Gas Boilers**	**Gas Boiler Only**	**CHP Only**	**HP Only**	**MV**	**MV Saving**
Base Case Cogeneration Exported to Grid	60.97	49.72	50.51	45.21	44.01	1.20
Cogeneration Used Locally	60.97	49.72	40.61	45.21	42.48	-1.87
Value of Additional Export			*9.9*		*1.5*	

Environmental Cost

In the reference case, single and multi vector CHP engines run when electric prices are high; displacing peak thermal generation, rather than renewables or nuclear baseload; the emissions offset by CHP generation are therefore based on the efficiency of a modern CCGT. Where CHP engines run at high load factors this may underrepresent the environmental cost, giving a lower bound on lifetime scheme costs. An upper bound can be found by calculating scheme emissions where CHP offsets electricity of national annual average intensity; the associated scheme costs are shown below.

Table 35- Effect of CHP Carbon Offset on Total Scheme Costs (£m) at a 3% Discount Rate

	DH Primary Plant					
CHP Emissions Offset Scenario	**Local Gas Boilers**	**Gas Boiler Only**	**CHP Only**	**HP Only**	**MV**	**MV Saving**
Base Case (CHP Offsets CCGT) Cogeneration Exported to Grid	60.97	49.72	50.51	45.21	44.01	1.20
CHP Offsets Grid Average Cogeneration Used Locally	60.97	49.72	47.84	45.21	43.63	1.60

Single vector CHP scheme operation costs rise by £7.2m – from £40.6m to £47.8m – cancelling out most of the revenue increase from sales over a local network; the greater exposure to carbon prices undoes the value of local supply. Multi vector scheme economics are largely unchanged; the additional cogeneration revenue leads to a minor scheme cost decrease of £0.4m, or around 1% of lifetime costs.

CHP Export

The sale of cogeneration to the grid is worth around £9.4m over the project lifetime - 15% of the single vector CHP scheme running costs, and an increasing amount each year - from around £373,000 in 2021 to £724,000 in 2044.

Depending on network topology, and the order in which generators connect, there may be insufficient network capacity to export CHP generation to the grid even under high wholesale prices - e.g. if a renewable generator on the same HV feeder is exporting at full output. The distribution of hourly export value is shown below.

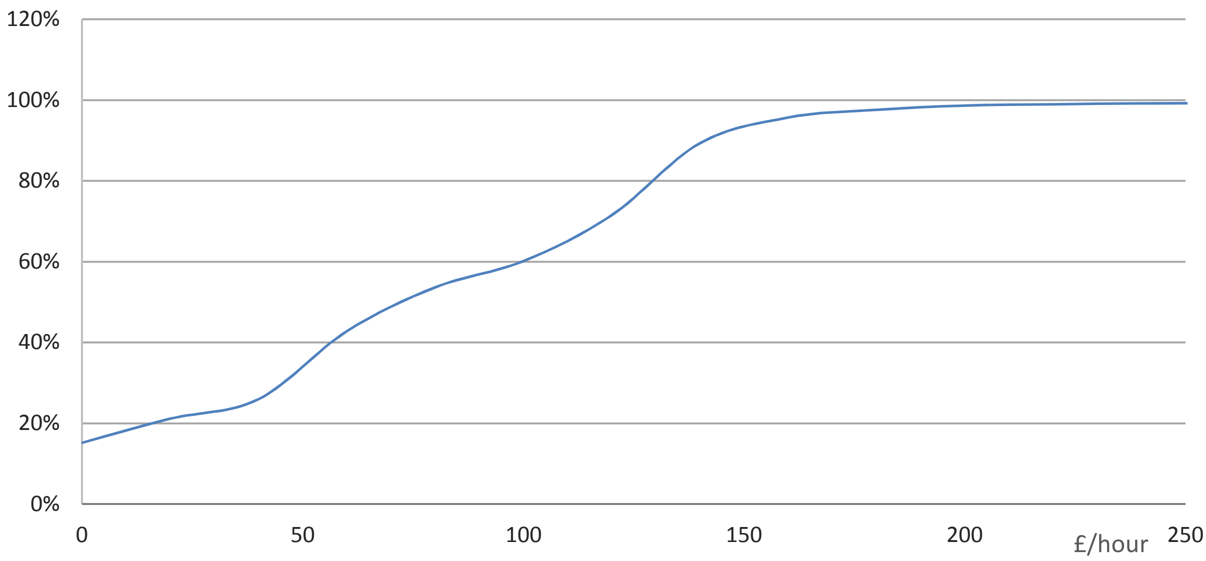

Figure 32 –Cumulative Distribution of 2030 Single Vector CHP Export Revenue Value

Per MWh export value spans a large range, with some value seen 85% of the time, and a mean of £81. The distribution is also highly skewed; the median is £70, and the maximum value is over £2,000.

There is also significant seasonal variation in export value, driven by;

i. The correlation of thermal and electrical demand
ii. The increased CHP load factors during colder months.

which suggests that a CHP scheme competing for network capacity with a solar PV array would do better than one competing with a wind farm.

Table 36 –Seasonal Average Value of Single Vector CHP Export

Season	Average CHP Export Value (£/hour)	Value Share	Average Electrical Price (£/MWh)
Spring	83.1	26%	53.3
Summer	42.3	13%	50.3
Autumn	91.4	28%	52.1
Winter	107.9	33%	57.1

Where electrical generation offsets local demand, single vector CHP is the lowest operating cost means of heat supply at carbon prices below £120/tonne, making it the lowest overall cost option (higher discount rates emphasise this effect, given the lower capital costs of CHP). However, where CHP operates at high load factors and displaces low carbon electricity, its exposure to carbon price increases, and it becomes increasingly expensive. Where CHP power offsets grid average, rather than CCGT generation, multi vector supply is around 10% cheaper than CHP only operation.

A constraint on CHP export, due for example to network constraint, can cost a single vector scheme up to 15% of lifetime scheme costs, with network curtailment during winter costing around 2.5 times more than in summer. Multi vector export revenues are minimal, worth less than 1% of total scheme

Network Temperature

Heat networks supplying thermally inefficient buildings and homes with radiators sized to legacy flow and return temperatures (72-80℃ and 60-70℃ respectively) must run at higher temperatures. In this section, we investigate the effect of increased network temperatures on project costs.

At a network flow temperature of 75℃:

i. Ground source heat pump CoP falls (from 4.4 to 3.4).
ii. Losses from the network increase by around 30%.

The lifetime scheme costs are shown below.

Table 37- Effect of Network Temperature on Total Scheme Costs (£m)

	DH Primary Plant					
CHP Emissions Offset Scenario	**Local Gas Boilers**	**Gas Boiler Only**	**CHP Only**	**HP Only**	**MV**	**MV Saving**
Base Case (Low T)	60.9	49.7	50.5	45.2	44.0	1.20
High T	60.9	50.1	50.9	48.8	45.0	3.8
Additional Cost		*0.4*	*0.4*	*3.7*	*1.0*	

Scheme prices increase in line with their exposure to increased electrical demand of the heat pump;

i. at the lower CoP, heat pump lifetime costs under optimal operation increase by £3.7m
ii. the multi vector scheme costs increase by £1m - around 25% of the heat pump scheme figure

Of these cost increases, £0.4m are due to increased heat losses.

Primary plant is sized to 50% of peak demand, and around 20% of heat is supplied by gas boilers. It may be possible to use a heat pump to raise water temperatures to 60℃ (at a higher CoP) and the gas boiler to then raise the temperature to 75℃, rather than both to generate heat at the higher temperature. On this basis, the cost increases above may represent upper bounds, rather than central estimates.

For multi vector operation, the balance between heat pump electrical import and CHP export costs changes, and CHP exports are significant during the early project years.

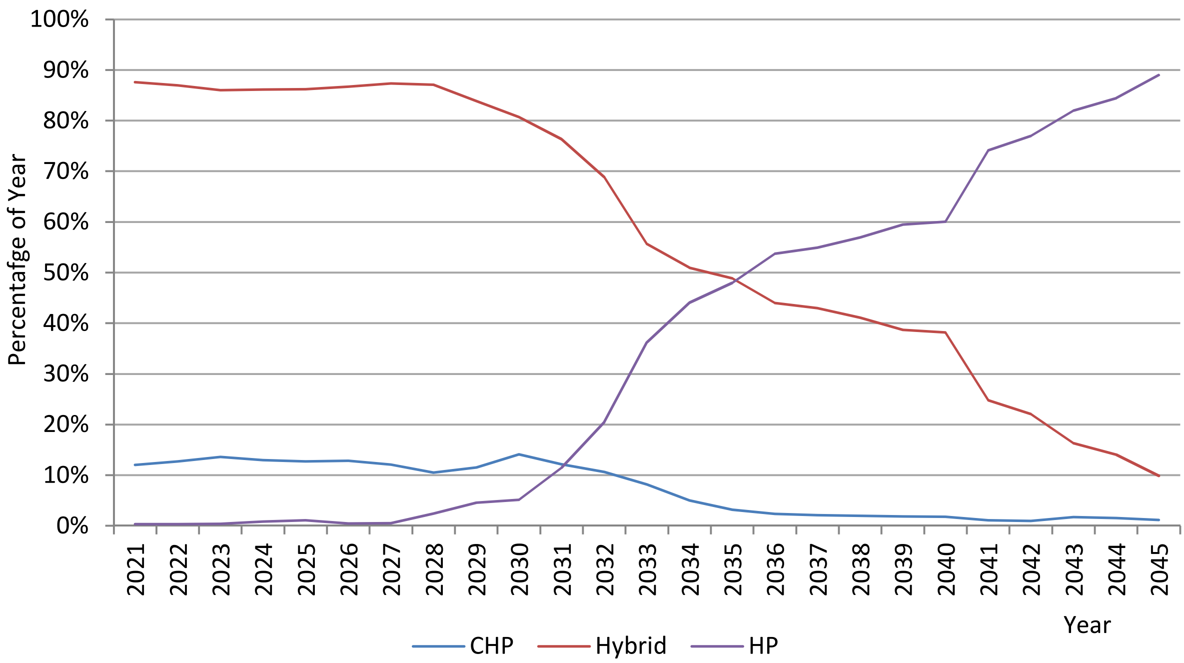

Figure 33 - Multi Vector Heat Supply Mode Share by Time, 75℃ Heat Network Temperature

Multi vector heat supply remains the lowest cost low carbon solution (and CHP the highest) for heat supply to legacy buildings.

Build Year

The CCC report *Research on District Heating and Local Approaches to Heat Decarbonisation* predicts increasing commissioning of heat networks each year until after 2030. District heating projects built in the next 10 years will see different relative values of electricity, gas and carbon prices throughout their lifetimes; the effect of commissioning date on lifetime scheme costs is shown below.

Table 38- Effect of Build Year on Total Scheme Costs (£m)

	DH Primary Plant			
Build Year	**CHP Only**	**HP Only**	**MV**	**MV Saving**
2016	43.07	42.12	41.34	0.74
Base Case (2021)	50.51	45.21	44.01	1.20
2026	58.05	46.52	45.78	0.74

CHP heat supply with grid export of cogeneration in 2016 is around £200,000/MWth more expensive than multi vector systems, and becomes increasingly expensive as carbon prices rise.

The increasing carbon price is drives decarbonisation of grid supply; the environmental costs of electricity rise and then fall relative to gas combustion, so multi vector saving over heat pump use peaks around 2021 and is lower for both earlier and later schemes.

We note that for a scheme built in 2016, the optimal multi vector plant size is only 25% of peak thermal demand; half the 2021 value, though the additional scheme costs for larger plant are not large, as shown below.

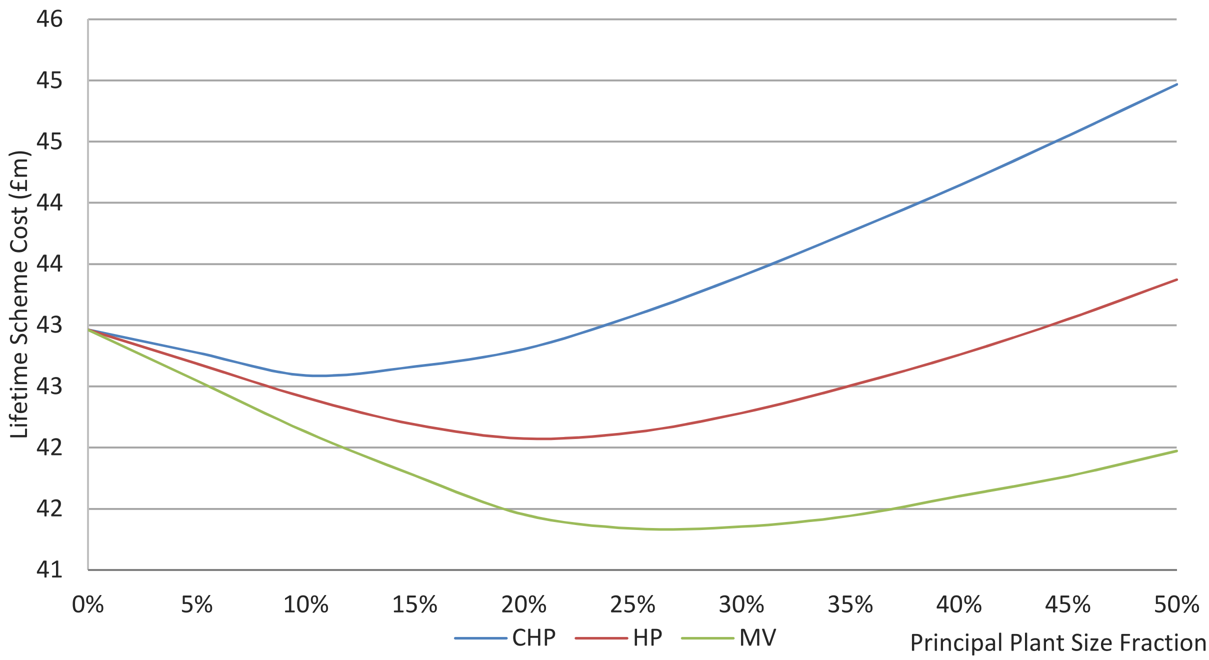

Figure 34 - Lifetime Project Cost for a Scheme Built in 2016

For schemes commissioned from 2016 onwards grid connected CHP is not an economic means of district heat supply, unless the electrical generation can be used locally.

The value of the multi vector solution rises in the short term, as it depends on:

i. a carbon price that is high enough to encourage low carbon heating, between £60 and £100/tonne
ii. a grid that is sufficiently decarbonised that electrical prices are not exposed to environmental costs

Other Multi Vector Configurations

Multi vector value comprises avoided grid use charges and fuel price optimisation; CHP and heat pump operators can form a multi vector heat supply system – and thereby access this value – through the electrical connection of their plant, even where they are not in the same location. This value may be sufficient for a CHP operator to finance the purchase of an appropriately sized heat pump, or heat pump operator of a CHP engine, to augment their existing plant.

Specifically, a multi vector CHP engine is sized to around 40%, the heat pump to 60%, of the size of its single vector equivalent; a 1MWth CHP engine might be included in a 2MWth single vector, or a 5MWth multi vector, DH scheme. From Figure 20, it is apparent that despite the additional £3m capital cost of a 1.5MWth heat pump, the latter scheme's lifetime costs are £4m less - by the same argument, the operator of a 3MWth heat pump might buy a 2MWth CHP engine and reduce overall scheme costs by around £1m.

Capturing this value requires that:

i. The operator can supply sufficient simultaneous heat demand at the same price, and
ii. The costs of electrical connection (and any other required infrastructure e.g. further heat network development) are not greater than the operational savings (at relevant discount rates).

Examples of this synergy might include two DH developers connecting their respective nearby CHP and heat pump schemes through a private wire, or a new CHP district heating scheme installing heat pumps in several large, existing nearby buildings through bespoke electrical connections to supply their heat and hot water requirements[49].

> The electrical inter connection of CHP and heat pump schemes creates value for both - even for schemes that operate one but must purchase the other; this value must however be weighed against the cost of electrical connection, and the potential benefit that may be realised though connecting to other private wire counterparties, or offsetting local demand.

Discount Rate Implications for Subsidy Design

Low carbon thermal plant is capital intensive; even at the carbon prices used in this analysis, high discount rates result in rational scheme developers, operating high hurdle rates, under-sizing their low-carbon plant. As seen in Table 27, the Gas Boiler Only option is cheapest at high discount rates, this holds for all but one of the sensitivity scenarios considered above. This Value Gap – the difference between the 10% discounted gas boiler only and socially optimal multi vector heat supply option – is shown below for each scenario.

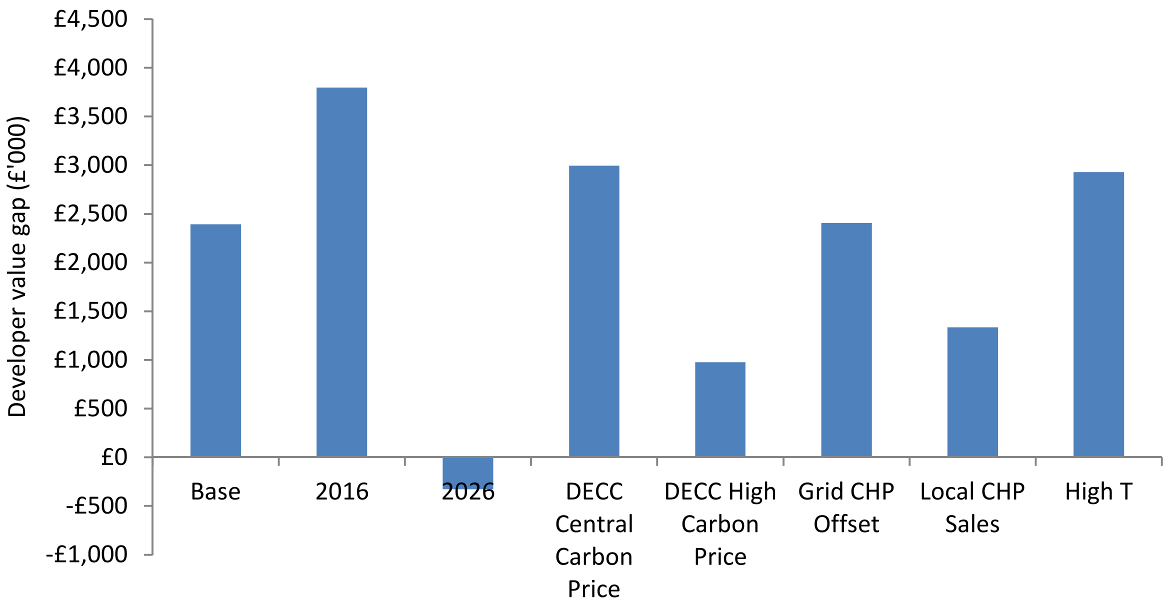

Figure 35 – Developer Value Gap by Scenario (£ '000)

[49] This option would also require additional thermal plant in these buildings, for peak supply and e.g. times at which electrical prices are so high that CHP cogeneration is most cost effectively sold to the grid.

While planning and building development regulations typically require some low carbon plant as part of any heat network, developers may undersize their low carbon plant, unless subsidies make some long term social value available as developer incentives.

Applicability

Thermal Demand Profile

The analysis above considers new, thermally efficient buildings, in which energy demand for hot water comprises a large fraction - 35% - of total supplied heat (although the effect of higher network flow temperatures, suitable for existing buildings, is considered in the sensitivity analysis above, the relative size of space heat and hot water demand is unaltered). Summer heat demand - and therefore plant load factors - are higher than in existing district heating schemes of similar sizes; this may affect the absolute, but not relative, analysis.

Due to the large connection numbers modelled, the heat profile is highly diversified diurnally, as well as seasonally. Smaller schemes can however smooth out demand profiles through heat storage and network optimisation, this should not therefore limit the relevance of this analysis.

Alternative Heat Supply Options

Bio-CHP

Standalone CHP suffers in this analysis due to the high carbon prices; a biofuel CHP might prove more competitive. The carbon cost of standalone CHP, scaled to peak thermal output, is shown below at a range of discount rates.

Table 39 – 25 Year Single Vector CHP Emissions Cost Scaled to Engine Thermal Output

Discount Rate	Scaled Lifetime Emissions Cost (£m/MWth)
0%	3.67
3%	2.36
10%	0.97

The capital costs of a biomass CHP are between £1.5m/MWth and £2.5m/MWth greater than for a gas CHP of similar thermal and electrical efficiency[50]. Whether a biofuel engine would outperform a gas-powered alternative, and the heat pump or multi vector configurations, will therefore depend on:

i. The size of the scheme.
ii. The relative gas and biofuel energy costs.
iii. The financing of the project.

Operational concerns around e.g. fuel delivery would also need to be considered.

Biomethane can also be used in a CHP; for sufficiently cleaned-up gas the additional capital costs for the project would be zero. For net zero carbon gas, the fuel costs alone would determine relative 25 year project costs; the carbon cost component of gas increases from 1.7 to 3.7 times the fuel price,

[50] Ricardo-AEA, Bespoke Gas CHP Policy - Cost curves and Analysis of Impacts on Deployment (2015), GLA Decentralised Energy Capacity Study Phase 2 (2011)

so biomethane at e.g. twice the price of natural gas would represent a viable alternative to single vector CHP, and potentially heat pump and multi vector, heat supply.

Gas Engine Heat Pumps

Gas engine heat pumps use a gas engine to move fluid around a heat pump, and operate at a CoP of around 1.5, similar to that of the hybrid multi vector configuration; indeed, a gas engine water-or-ground source heat pump is effectively equivalent to hybrid multi vector operation, but without the ability to import and export electricity.

As explored in the section on Plant Use, the option to switch to CHP-export and heat-pump-only mode is worth around £0.1m/MWth over 25 years. The capital costs of multi vector primary plant (sized to 50% of peak demand) are less than £1m/MWth, the costs of a gas engine heat pump would therefore have to be below £0.9m/MWth to represent a viable alternative, though grid connection costs are avoided in the latter case.

Micro CHP

In principle, the findings of this analysis are applicable to a range of scheme sizes, including micro heat networks serving individual buildings. In such cases however, the fixed and per kW overhead and network connection costs, logistical factors and physical constraints may complicate the analysis.

3.2.4 Key Findings

The analysis presented above suggests the following medium term benefits of multi vector heat supply – using gas CHP and heat pumps in tandem:

1. Multi vector operation represents the lowest cost heat supply option over a range of medium term energy system projections (where carbon prices are high enough for heat networks to compete with local gas boilers). Long-term carbon prices make grid powered heat pump preferable, but multi vector supply may represent an intermediate step in the decarbonisation of heat; a scheme might for example use a CHP engine to power a heat pump for 15 years, decommission it and replace it with an additional heat pump.

   As multi vector operation inherently hedges against fuel price movement, multi vector schemes are insulated against the risk of price increases; multi vector benefit increases as a function of electrical price volatility, though it is positive at constant annual prices.

2. The NPV of multi vector heat supply is between £75,000 and £125,000/MWth over the project lifetime (at a 3% discount rate), comprising capital, fuel and running cost savings. The capital costs of a multi vector centre are around £120,000/MWth lower than for a single vector heat pump only scheme; the main saving of a multi vector over a heat pump heating scheme comprises the lower per-MWth capital cost of gas CHP compared to ground source heat pumps.

3. Hybrid multi vector operation - in which CHP cogeneration is used to power a heat pump - is the lowest cost heat supply option for over 90% of annual operation at carbon prices below £90/tonne. Gas engine heat pumps are an equivalent technology; given their CoPs of around 1.5, either technology could allow gas to operate as a heating vector at higher carbon prices than burning it in boilers.

   As multi vector schemes run in hybrid mode for a large fraction of their operational lifetime - particularly in the earlier, lower carbon price years - it is possible to run a DH scheme by connecting it to the gas network only - this increases lifetime costs by around 2%.

4. Multi vector heat pumps use grid power when electrical prices (and therefore system stress) are low, and export to the grid when prices are high, thereby stabilising the grid, which gas engine heat pumps cannot.

   Standalone CHP exports to the grid at a lower cost than OGCT, at a level of 25% of peak thermal demand. Due to their environmental costs, grid exporting gas CHP schemes are unlikely to outcompete alternative heat supply, though biofuel CHP may.

5. Despite the higher lifetime carbon emissions of the multi vector scheme over the single vector heat pump alternative, multi vector heat networks provide the lowest cost means of emissions reduction, at between £30 and £50/tonne CO_2e (compared to gas only heat supply). Policy architects seeking to decarbonise heat, might build two multi vector schemes, rather than a single heat pump network.

6. While marginal carbon abatement costs remain below £90/tonne, the lowest cost means of decarbonising heat networks is not to use CHP or heat pumps alone, but to use both in tandem. Multi vector heat supply encompasses a range of configurations; an energy centre running a heat pump and CHP engine is the most obvious, but CHP and heat pump operators who connect their plant both stand to benefit. Further; through the purchase of a heat pump, a CHP operator may serve an expanded network at a lower cost of heat (or vice versa).

7. Where carbon or electrical export prices are very high, single vector supply outcompetes multi vector.
   - At carbon prices above £125/tonne, single vector heat pumps outperform multi vector configuration, (depending on the extent to which electrical generation is decarbonised).
   - CHP-only schemes do better where cogeneration value is high, for example where cogeneration offsets local demand - marginal power prices then effectively include the network use charges, which account for around half the cost of imported electricity. Where CHP displaces low carbon electricity from local supply however, its effective carbon intensity increases, which may make it unviable.

8. Electrical network charges are levied on per MWh, time-of-use, basis. As multi vector scheme use the power grid less than their single vector counterparts, operators are incentivized to choose multi vector supply as it effectively socialises some part of these charges. Unlike in the previous case study, it is therefore not obvious to what extent multi vector heat supply provides a system level benefit.

9. In addition to the considerable heat network costs, low carbon plant is capital intensive; at high discount rates – above 10% - multi vector heat supply remains the lowest cost means of low carbon thermal generation, but has greater lifetime costs than gas boiler only supply. At around 30% higher than that the latter – (an additional £6.70/MWh, or 20% of current domestic fuel price of heat) – multi vector heat supply will require a subsidy which converts future value into current developer returns.

3.2.5 Operational and Engineering Implications

Challenges associated with the transition to multi vector operation have been collated through consultation with industry stakeholders and other experts, and are summarised in the table below. Further analysis is provided in the accompanying report *Barriers to Multi Vector Energy Supply.*

	Issue	Impact and Solution / Mitigation
Commercial / Technical	Hourly optimisation of the heat supply mode based on electricity prices	Optimising heat supply as above requires that the system operator is exposed to time-varying prices, and then make choices about heat supply mode on a continuous basis, i.e. real-time pricing for demand and generation. Given logistical and setup costs, it may be lower cost to secure a long term PPA, particularly for smaller schemes.
Technical	Effect of heat pump on local network	The multi vector heat pump is powered by CHP cogeneration - and therefore off-grid - much of the time; however, at times the full electrical input capacity of the heat pump is imposed on the electrical network, hence an adequate connection capacity will be required, but will be initially under-utilised. Over time, CHP operation becomes increasingly expensive as carbon prices rise, and heat pump only operation is favoured for an increasing fraction of the time. The CHP may therefore be decommissioned at the end of its operating lifetime, and potentially replaced with a second heat pump; at this point, the full grid connection is utilised at a higher capacity factor, and may even require reinforcement.
Technical / Operational	Management of the thermal output of CHP and heat pumps and the in a multi vector arrangement.	Heat from the CHP must also be utilised to achieve the carbon and economic benefits of the hybrid system. On a high temperature network, provided a low enough network return temperature can be maintained, the heat pump might be used to provide the initial heating of the return flow before the output of the gas CHP boosts the temperature to the required flow. In a medium or low temperature network, (which provides overall efficiency gains if supplying suitable buildings), there may however be difficulties in efficiently using the higher temperature CHP heat. During times of low thermal demand, modern heat pumps can reduce their output to 15-20% of their rated capacity (due to variable speed compressors). Gas-fired CHP however may not be able to modulate its output in the same way; reciprocating engine CHPs for example typically perform less efficiently at partial load. There may be issues in matching the CHP output to heat pump demand in hybrid mode during times of relatively low heat demand. The CHP could operate with partial grid export, i.e. to supply the heat pump and export the remainder to the grid, however this is may result in heat rejection. Thermal storage could potentially manage this, however over summer periods of prolonged low heat demand this is likely to necessitate very large thermal stores.

Technical / Commercial	Provision of Ancillary Services and Idling	Gas turbines are currently the main source of short and medium timescale turn-up services, such as Frequency Response (FR) and Short Term Operating Reserve (STOR) which require providers to increase their generation on timescales of a few minutes or two hours respectively. To enable ramp up on an FR timescale, turbines typically operate at 90% output, while to provide STOR they typically run at "hot standby", in which the plant is kept warm but produces negligible output. To allow the CHP to ramp up and down in response to movement in the electrical price, both the CHP engine and boilers would have to run in a similar low-throughput mode. As above, heat generated might be supplied to the network or stored, depending on thermal demand levels and the value of ancillary service provision.

3.3 Case 3: PiV Fuel Switching

3.3.1 Introduction

Context

As transport is electrified, many electric vehicles are being produced with both an internal combustion or diesel engine, and an electric motor; the former is generally conceived of as a range extender, with vehicles driving on liquid fuels only when their batteries are depleted. Nevertheless, a significant amount of transport energy demand may be supplied by different vectors as well as moved around in time (through smart charging) and space. In this case study, we review the system level benefit of the former option.

The environmental case for the transition to electric vehicles is underpinned by the parallel large-scale decarbonisation of the grid; by the second quarter of the 21st century, over 40% of generation will be renewably supplied. Individual renewable generators are however intermittently subject to multiple day periods of reduced output, for which the energy system design must include provision. In an extremal[51] low wind speed period in winter (for example during a high-pressure system over western Europe), it may be cheaper to meet PiV demand by incentivising petrol or diesel use, rather than by building peaking fossil fuel plant to generate electricity, and distributing this to charge points around the country. Further, removing vehicle demand from the power system may allow prices for other users to fall significantly, if the marginal supply cost curve is very steep, though as the sophistication of electric vehicle charging increases, fuel switching is only likely to be required during prolonged periods of electricity system constraint, where single vector demand management solutions – time management of electric vehicle charging and power storage - are insufficient to mitigate the constraint.

The Element ECCo scenario analysed has been chosen for the high uptake of hybrids. Under this scenario 7.3m hybrid petrol and diesel cars and a further 1m hybrid vans, referred to here as plug-in-vehicles (PiVs), (as distinct from pure battery electric vehicles (BEVs)), will be on the road by 2050, and will consume a total of 9TWhe in that year; around 25 GWhe daily.

Table 40 – BEIS Projected Share of UK Electricity Supplied by Renewables

Year	Share of Generation Supplied by Renewables[52]
2020	38%
2025	44%
2030	41%
2035	42%

[51] As in the Met Office definition – “The meteorological or statistical definition of extreme weather events is events at the extremes (or edges) of the complete range of weather experienced in the past”.

[52] Updated energy and emissions projections: 2015

Case Study Aims

Most energy system models, including the Element ECCo model, assume that PiVs are driven on batteries where possible. The objectives of this Case Study are to identify circumstances when there may be system benefit in switching to liquid fuel operation, and to determine the degree of generation stress required for liquid fuels to represent a lower cost energy supply vector than electrical generation for hybrid vehicles.

3.3.2 Scenario Definition and Assumptions

In this Case Study, we determine under what circumstances total generatable electricity can present a severe, prolonged constraint on the energy system, and if this constraint can be eased by moving most of the electrified transport fleet onto liquid fuels.

We model hourly electrical prices during a two-week low wind speed period in mid-January 2050 and calculate the supply cost savings associated with moving the energy demands of the 8.3 million PiVs from the electrical grid to a liquid fuel supply vector. Given the increasing demand manageability of electric vehicle charging, fuel switching provides value to the energy system only where liquid fuel is less expensive than electrical supply for periods of several days – otherwise smart charging will ensure sufficient energy can be delivered to vehicles for at-home and depot charging.

The demand management of buses, coaches, HGVs and other large road vehicles, for which electric/liquid fuel hybrids are not market-ready, are not considered in this study.

Electrification of Transport

The ECCo model breaks cars and vans down by engine, fuel type and purchasing agent. It determines car and van uptake numbers based on rational consumer choice given the yearly costs, tariffs, operating margins and driving demand specified in the input; the choices used for this scenario are based on those used as the Baseline Business-as-Usual case from the ETI CVEI project, with the following modifications:

- Electricity prices are taken from the *BEIS 2015 Reference Scenario*
- Fuel prices are calculated from *BEIS Updated Energy & Emissions Projections - September 2014 (Annex M)*
- Vehicle parc and kilometres travelled (VKT) are taken from ECCo's default values (calculated from DfT data in *Road Traffic Forecasts 2015*)
- Access to charging infrastructure settings are taken from ECCo's default values

The corresponding PiV uptake and 2050 stock breakdown are shown below.

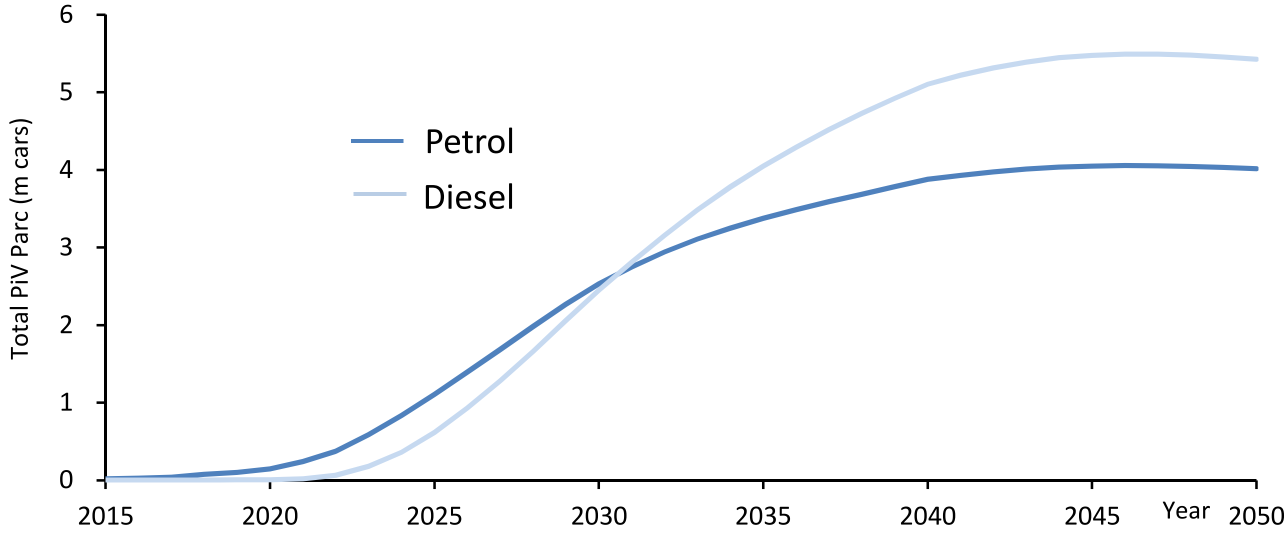

Figure 36 - PiV Uptake Projections

Table 41 - 2050 Car Fleet and Energy Demand

System Total	Car					
	Petrol	Petrol PiV	Diesel	Diesel PiV	BEV	FCEV
Total Number (m vehicles)	15.0	3.6	8.7	3.7	4.6	1.1
Electrical Demand (MWh)	0	2,954,470	0	3,978,840	8,871,910	0
Petrol Demand (m^3)	6,688,520	581,726	0	0	0	0
Diesel Demand (m^3)	0	0	3,922,560	640,334	0	0
Hydrogen Demand (tonnes)	0	0	0	0	0	83,129

Table 42 - 2050 Van Fleet and Energy Demand

System Total	Van					
	Petrol	Petrol PiV	Diesel	Diesel PiV	BEV	FCEV
Total Number (m vehicles)	0.1	0.3	4.3	0.7	2.2	0.3
Electrical Demand (MWh)	0	478,000	0	1,391,100	9,271,300	0
Petrol Demand (m^3)	140,248	167,021	0	0	0	0
Diesel Demand (m^3)	0	0	4,964,700	345,250	0	0
Hydrogen Demand (tonnes)	0	0	0	0	0	104,604

For the PiV categories in the ECCo model, we calculate the relative electrical and liquid fuel efficiencies as the energy content delivered divided by the distance driven in each mode[53]; the liquid fuel efficiencies range from 21% to 30% of the electrical supply values. At times of generation constraint, the model determines for each PiV category whether to switch vector based on its specific fuel and electrical efficiencies, and therefore relative costs.

Operation and Economics of Liquid Fuel Distribution System

In the ECCo scenario:

1. 45m cars and vans are on the road in 2050 - up from 33m in 2016.
2. The 2050 number of ICE and diesel cars on the road is 80% of the 2016 total.
3. The system throughput of liquid fuel has fallen further - to less than half its 2016 levels - due to increasing engine efficiencies[54].
4. In 2050, there are around 6,000 petrol stations in the UK, compared to around 8,000 in 2016. This number is the minimum required to provide access to liquid fuel to all drivers, rather than by purely economic considerations, as calculated in the ETI CVEI project. We note that current there a subsidy is available to off-grid petrol stations[55].
5. Most – around 65% - of the PiV energy demand is served by liquid fuels.

The system cost of liquid fuel supply in the model comprises

1. A fuel cost, based on the projected oil price. As we consider competition between fossil fuel generation and liquid fuel as a transport energy vector the oil price is pegged to the BEIS gas price projection. Given the current oil price of £40/barrel and the increase in the gas price, we estimate an equivalent oil price of 34p/litre.
2. An ex-refinery spread covering delivery of the fuel; based on UKPIA report[56], this is taken as 6p/litre. The ex-refinery spread comprises between 12 and 16% of the underlying fuel price, based on BEIS weekly average at pump fuel prices), giving a system level supply cost of fuel of 40p/litre. This margin does not seem to depend on the number of stations; however as liquid fuel throughput has remained roughly constant over the last 20 years, it is difficult to assess the effect of falling throughput on network capacity reduction and marginal distribution costs.

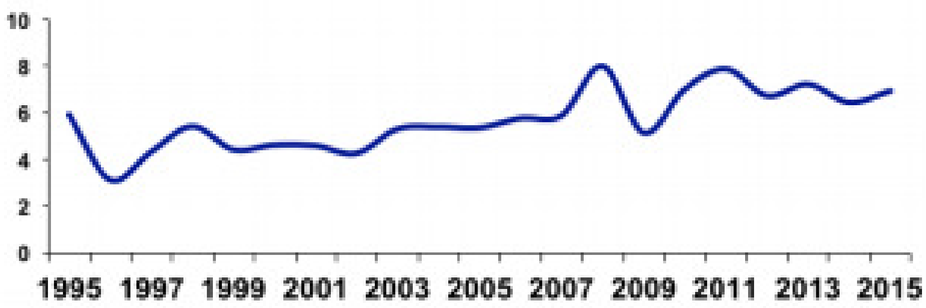

Figure 37 – Ex Refinery Margin 1994 to 2016 in p/litre. Source: Wood-Mackenzie

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[53], As more motorway driving will be done in petrol mode, (and more urban driving in electric mode), this may overestimate the liquid fuel efficiency.

[54] Again, HGVs and buses are excluded from this analysis.

[55] Rural Fuel Price Cut Begins

[56] UKPIA - Understanding Pump Prices

3. A carbon price - taken from the 2050 BEIS projections - of £212/tonne. This represents a surcharge of around 56p/litre for petrol, and 64 p/litre for diesel (though on a delivered energy basis, the cost for diesel is slightly lower). On this basis, the 2050 ex-refinery cost of liquid fuels comprises mainly the carbon price; this component is very like the current UK government duty on liquid fuels at 57.5p/litre.

   The system level 2050 liquid fuel price is therefore around £1.0 /litre - 10 p/kWh.

As it is unclear how clean vehicle engines will be by 2050, NO_x, particulate matter and other air quality impacts of combustion engines are not priced in our model.

Low Wind Speed Period Capacity Factors

The two-week minimum average wind, solar and hydro capacity factors are based on a review of 10-minute Gridwatch, and annual renewable capacity DUKES, data from 2010 to 2016.

Table 43 – Historical Minimum Weekly Wind Fleet Capacity Factors - DUKES and Gridwatch Data

	Min Weekly Capacity Factor (%)	
Year	Winter Only	Annual
2012	10%	7%
2013	12%	7%
2014	14%	5%
2015	11%	9%
2016	13%	7%
Min	**10%**	**5%**

Based on these data, contingency scenarios for extremal winters are show below.

As offshore wind, which operates at higher capacity factors than its onshore counterparts, comprises an increasing fraction of total wind capacity, minimum capacity factors are likely to increase over the period to 2050. We therefore include 15% as a typical minimum weekly winter capacity factor for 2050.

Table 44 – Contingency Minimum Weekly Wind Fleet Capacity Factors

Contingency	Winter Min Weekly Capacity Factor (%)
1:1	15%
1:5	10%
1:20	5%

Electrical Generation Fleet

Hourly electrical prices are then calculated in PLEXOS for the year, with wind farm output constrained to 15% of its total capacity[57]. A DNO ToU grid usage charge is also included to capture the network use costs, and the emissions cost is included in the ESME model. Based on the ESME fuel and capital cost data and the forward learning curves, 2050 peak electrical generation is likely to be provided by OCGT; as relatively low cost, low efficiency plant.

Table 45 – ESME Generation Fleet Breakdown

Generation Type	Installed Capacity (GW)
OCGT	Marginal
CCGT	4
CCGT with CCS	16
H_2 Turbine	10
Hydro	3
IGCC Biomass with CCs	0
Nuclear	27
Offshore Wind	70
Onshore Wind	20
Tidal Stream	1
Waste Gasification with CCS	2
Total Renewable	**94**
Total Other	**59**
Total	**153**

3.3.3 Case Study Analysis

In the two-week period for which prices have been calculated, total PiV electric demand is around 338 GWh - 3.8% of total. Electrical prices in the period rise to a maximum of £330/MWh wholesale, around £440/MWh once peak time of use charges are included.

Electrical energy supply costs rise above those of liquid fuels for a maximum of 19 consecutive hours, and a shorter period of 16 hours; electrical liquid fuel supply prices and the hourly system switching value are shown below. The total electrical generation costs in these two periods is £14m; the additional liquid fuel supply cost is £10m. With 8m PiVs, this represents an incentive of around 60 pence per driver; although all vehicles may not be required to switch, the degree of saving is unlikely to drive significant behaviour change.

[57] The model has not converged for more drastic constraints on wind farm output.

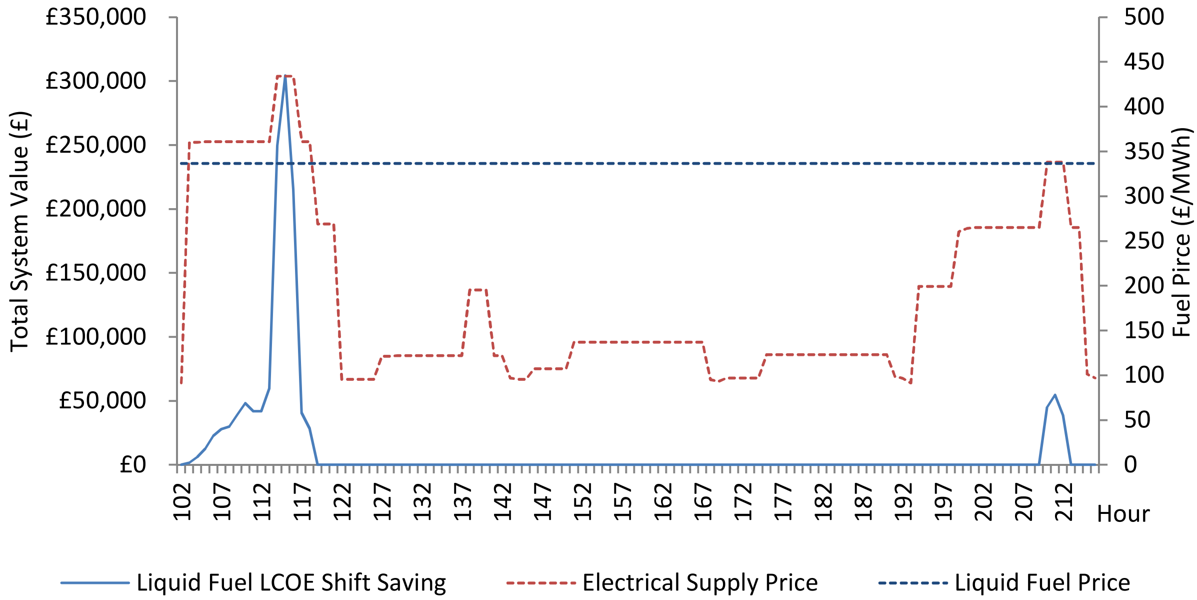

Figure 38 - Hourly Energy Prices and Fuel Switching Value for 5th to 9th January

Contingency Peak Plant

Given that power prices do not appear to drive significant fuel switching, we now consider explicitly the provision of peak electrical supply.

In the ESME high-renewable scenario, peak electrical generation is provided by thermal plant, with nuclear providing around 27GW of baseload. The capital and run costs, and the 2050 scenario economic assumptions from ESME are shown below for OCGT.

Table 46 - OCGT Parameters 2050

Parameter	Value
Capital Cost	£428/kW
Annual Operating Cost	£27/kW
Gas Cost	£28/MWh
Efficiency	43%
Load Factor	90%
Carbon Cost	£212/tonne
Operating Lifetime	20 years
Discount Rate	8%

On this basis, OCGT operates at a 2050 short run marginal cost of £168/MWh, and – at a 90% load factor – a 20 year lifetime LCOE of £177/MWh; this compares to a delivered energy cost to vehicles using liquid fuels of around £340/MWh. The load factor of marginal OCGT would need to fall to below 5% for fuel switching to represent a viable energy supply management option.

Only at times of extreme grid stress does liquid fuel supply to PiVs come at a lower system cost than marginal grid generating plant; due to the higher round trip efficiency of electric vehicles it is almost always preferable to burn fossil fuels in a turbine and distribute it as electricity than as fuel to be burned in an internal combustion or diesel engine.

Peak Diurnal System Demand

The UK 2050 January load profile curve is shown below, (taken from 2016 Element data), as well as the demand breakdown, (taken from UK government population and energy efficiency projections, BEIS Heat Pump uptake estimates and ECCo BEV totals).

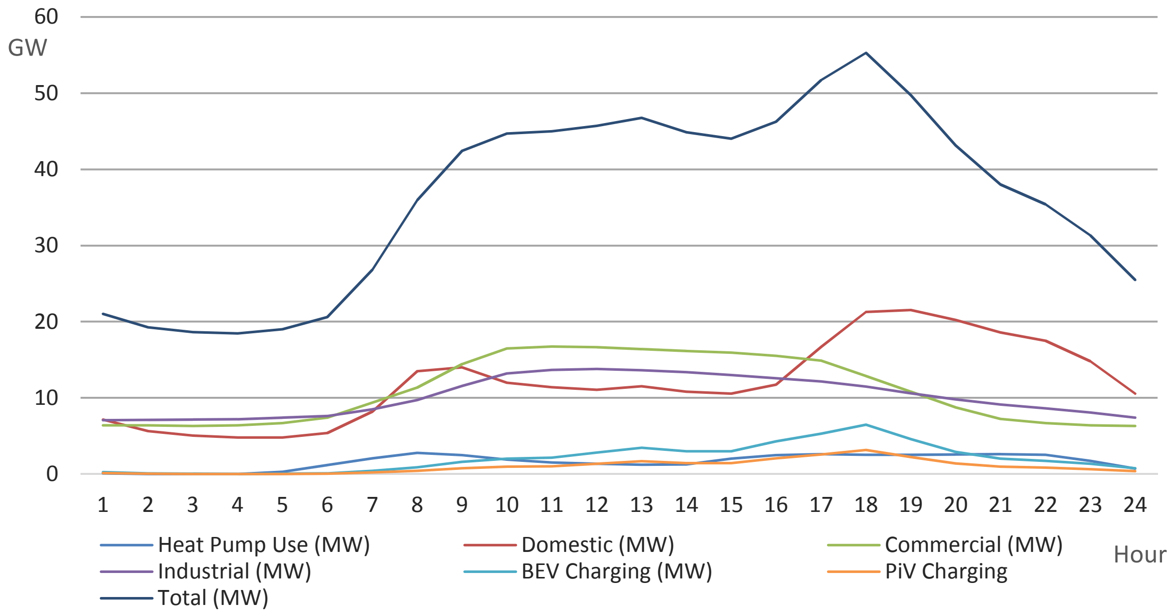

Figure 39 – 2050 January Peak Day Diurnal Demand Profiles

Table 47 – 2050 Electrical Demand Totals by Sector

Demand	Annual Total (GWh)
HP Demand	7,598
Domestic Demand	88,796
Commercial Demand	78,026
Industrial Demand	79,126
BEV	26,946
Total	**280,490**

Peak-day demand levels vary from 18.5GW in the early morning to 54.5GW in late evening; a difference of 36GW, while total daily electric vehicle demand is around 72GWh; if the generation system can meet the domestic, commercial and industrial appliance and thermal loads, EV demand must be deferred for only a few hours after peak to allow all vehicles to recharge.

A single vector load shifting solution is likely sufficient to enable PiVs to charge on a daily basis, even in a future where transport is highly electrified, and generation highly decarbonised.

Sensitivities

Gas to Oil Price Ratio

The oil price in this scenario is pegged to the BEIS gas price projections; were oil prices to fall dramatically relative to gas prices, the supply of PiVs by liquid fuel delivery may become more economic. We find however, that the gas-to-oil price ratio would have to rise to 3.3 times its current value for PiVs to be viably supplied using liquid fuels. Macroeconomic commodity price forecasting is outside the scope of this study, though we note that the oil price is currently at historically low levels relative to the gas price.

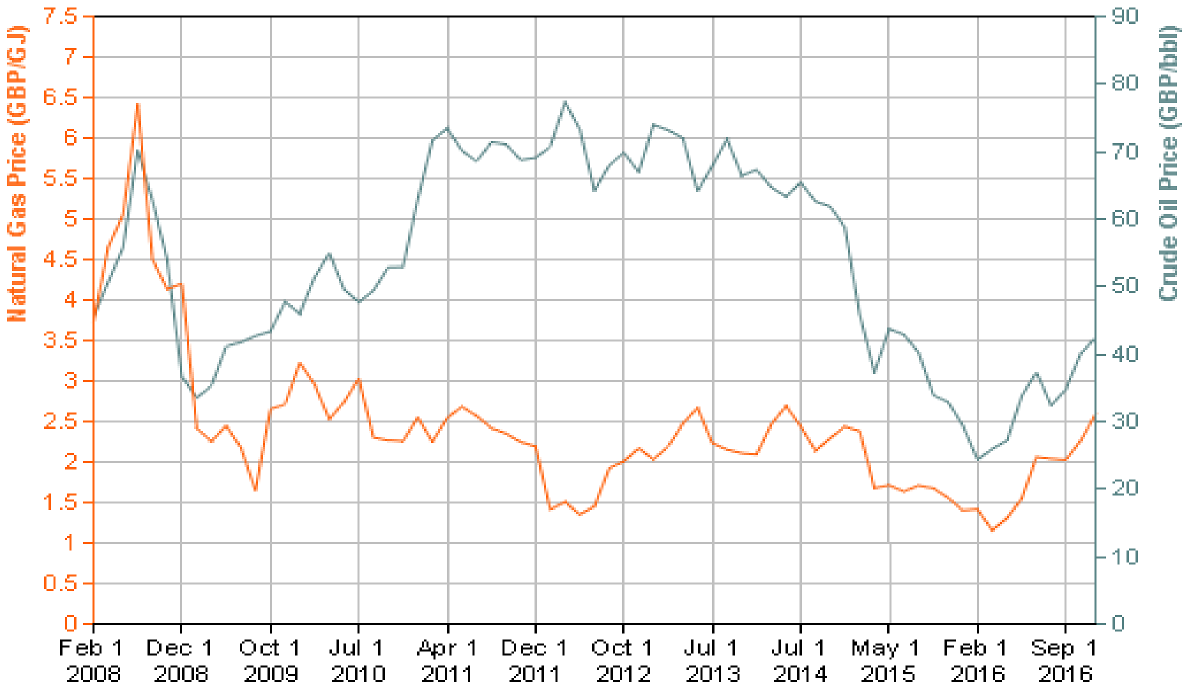

Figure 40 - Historical Oil and Gas Prices (£/GJ gas and £/Barrel crude oil)

Historically unprecedented movement in the relative prices of gas and oil would be required for petrol supply costs to compete with electric.

3.3.4 Key Findings

The analysis presented here suggests that PiV multi vector fuel switching is unlikely to play a significant role in energy system management or contingency planning to 2050.

1. PiV liquid fuel switching is – at best – a marginal multi vector supply option; the efficiencies of petrol and diesel engines and the high carbon price contribution to the cost of petrol in 2050 - between 45 and 60% of the total - mean that even during times of electrical generation constraint, total supply savings are negligible.
2. The inherent flexibility of vehicle charging makes fuel switching an unnecessary option; modelled electrical price peaks for a highly-decarbonised generation fleet are both too short and too narrow to justify investment in a fuel switching system. Prices above £340/MWhe are required to justify fuel switching, and even where such prices are seen they are not sustained for long enough that a single vector load management strategy is unable to provide electrical demand to most users.

At carbon prices of around £200/tonne CO_2e, 2050 OCGTs operate at a short run marginal cost of around £168/MWh; load factors would have to fall to below 5% for their long run marginal costs to rise above £340/MWhe.

3. Changing the carbon price does not materially alter these findings, as thermal generation plant is subject to the same levy. Although not explicitly considered here, environmental pricing of NO_x and particulate matter may further disincentivise the use of liquid fuels.
4. The oil to gas price ratio would have to move significantly from its current levels to affect the findings of this analysis – we note that oil prices are at historically low levels.
5. By 2050, the carbon price levied on liquid fuels will match current duty levels; were both levied the price of fuel would increase by around 75% on 2016 levels. The per km costs for the more than 20m liquid-fuel-only vehicles on the road in 2050 would fall however, due to increased average engine efficiencies.
6. This analysis finds no reason to incentivise PiV over BEV purchase, the additional engine costs appear justifiable only for operational requirements, such as range extension.

3.4 Case 4: RES to hydrogen/methane

3.4.1 Introduction

Decarbonisation of electricity is a fundamental part of the UK's pathway to meet its 2050 decarbonisation target. Renewables will play a very important role in achieving this, so there may be periods when electricity supply exceeds demand. This over-generation of low carbon, low cost energy could be exported to other markets (subject to their demand levels and interconnection capacities), otherwise, excess renewable energy may have to be curtailed, unless there is some way to store it for longer periods of time.

Electrolysis is a form of Power-to-Gas (P2G) technology, converting electricity into H_2 gas, which may then be:

- Blended into the existing natural gas grid (up to certain concentration limits).
- converted to methane using catalytic methanation; a common process for hydrogenation of carbon dioxide. In this case, the product is synthetic natural gas (SNG), which can be injected into the gas grid at any concentration.
- Used to supply other H_2 demand.

The first and second technologies allow the existing natural gas grid to be used as a storage solution; P2G provides the power sector with increased flexibility and allows for the cross-sectoral integration of surplus renewable energy in markets such as transport and industry that can benefit from further decarbonisation.

In this section, we review the economic viability of electrolysis (Power-to-H_2) and methanation (Power-to-SNG) as a means of mitigating renewable curtailment under 2050 scenarios where installed renewable capacity is high. The system benefit of multi vector configuration is then compared against the benefit of using economically sensible single vector means of alleviating curtailment.

3.4.2 Overview of Methodologies and Analytical Tools

System boundary

The Case Study boundary is the UK electricity generation and transmission system, the broader energy system is considered exogenous to the analysis; decisions made within the model boundary are assumed not to affect system and market operation in other parts of the energy system, such as gas networks or heat supply.

Whole energy system modelling

The potential of converting power to H_2 via electrolysis as a solution for dealing with renewable curtailment is examined under scenarios with increasing levels of wind generation capacity in the UK in 2050. These scenarios are generated using ESME V4.1, by constraining the 2050 build capacity of onshore and offshore wind to the desired minimum levels, i.e., enforcing minimum levels of installed wind capacity in the pathway optimisation model.

The ESME results in each modelled 2050 scenario include the installed generation capacity mix, electricity demand per seasonal and diurnal time-slice, as well as the required transmission capacity between UK regions allowing transmission of power to centres of demand. In each scenario, ESME also provides an H_2 shadow price which represents the cost of producing an additional unit of H_2. This is used as a proxy for the wholesale H_2 price, which drives the economic appraisal of electrolysis.

To ensure security of supply, ESME also models a number of related constraints, e.g. the electricity peak reserve constraint, which ensures that the total capacity of electricity generating technologies (adjusted for their contribution to peak capacity) exceeds the estimated peak electricity demand by a pre-defined margin. Another constraint ensures sufficient flexibility from the electricity generation fleet at a system level to meet estimated rates of change in electricity demand. However, frequency and spinning reserves are not explicitly modelled in ESME.

Hourly Operational Dispatch

After the generation mix and time-sliced demand results corresponding to the year modelled have been obtained using ESME for each modelled scenario, the ESME2PLEXOS tool is used to link ESME to PLEXOS, an electricity market modelling tool that determines electricity dispatch at an hourly level for a selected time horizon to minimise total generation costs. This allows for the ESME-based electricity system solutions to be explored from a more detailed operational dispatch perspective. In this case study, the time horizon is one full year (2050). The tool uses the following data, to create and run a dedicated PLEXOS model:

1. Exogenous hourly wind load factor profiles, based on historical data (2008) of different UK regions (mapped to the ESME regions following the same methodology as in the ETI CVEI project)
2. Exogenous hourly tidal and solar profiles, as per the ETI CVEI project
3. Time-sliced demand data from the ESME V4.1 model, smoothened using a Gaussian filter
4. Assumptions on plant technical characteristics as defined in ESME V4.1 database and provided by the ETI for use in the CVEI project (including min stable level, ramp up/down limits, start costs, heat rate curves etc.)

It should be noted that the model boundary reflects the UK only, which is modelled at a nodal level in PLEXOS with its interconnectors to Norway, Netherlands, France and Ireland sized as per the ESME V4.1 Reference Case. The systems on the other sides of the interconnector boundaries are not modelled in detail, instead each interconnector market is modelled in PLEXOS using a fixed price data series, calibrated from the Baringa Pan-EU PLEXOS model to deliver the analysis and allow the interconnector flows to be dispatched.

PLEXOS results include the hourly generation profile for each power plant in the system, hourly demand as well as transmission and interconnector power flow results for the whole year modelled. Given the regional (nodal) representation of generation and demand in the model, results are available for each geographical region in the UK. For this study, we are particularly interested in the hourly profile of renewable capacity curtailed in the UK, due to either limited transmission capacity between regions or national generation surplus. It is recognised that frequency and spinning reserves are not directly modelled in ESME and PLEXOS; as we assume that reserve is managed to avoid curtailment however; this will not directly affect the volume of curtailment.

Economic sizing of electrolysis (Power-to-H_2) and methanation (Power-to-SNG) plants

The capacity potential for electrolysis and methanation is assessed using an Excel spreadsheet tool, which uses:

a. the hourly renewable curtailment as calculated above,
b. exogenous technology-specific input data (e.g. Capex, OPEX, efficiency) and
c. the scenario-specific H_2/gas and carbon prices

Due to the duration curve of the hourly capacity curtailment, each incremental capacity unit of electrolysis (or methanation) will have a lower load factor, and hence a higher levelised cost (in H_2 or SNG terms), so the economically sensible capacity of the asset is found at the point at which the levelised cost of the marginal unit is equal to the H_2 (or gas) wholesale price. The levelised cost of H_2 is calculated from the annualised capital cost and the fixed and variable costs of an electrolyser.

The model assumes that only surplus renewable generation that would otherwise be curtailed, is converted to H_2 via electrolysis; the electrolyser does not purchase electricity but utilises (zero-cost) surplus electricity.

Given the boundary of the case, we make the simplifying assumption that the production of H_2 through electrolysis, or of SNG through methanation, does not materially affect the supply and demand balance of H_2, or natural gas respectively, in the wider system modelled in ESME. Therefore, H_2 and natural gas shadow prices are both fixed as originally given by each ESME set of results, and used as a proxy for the required wholesale prices.

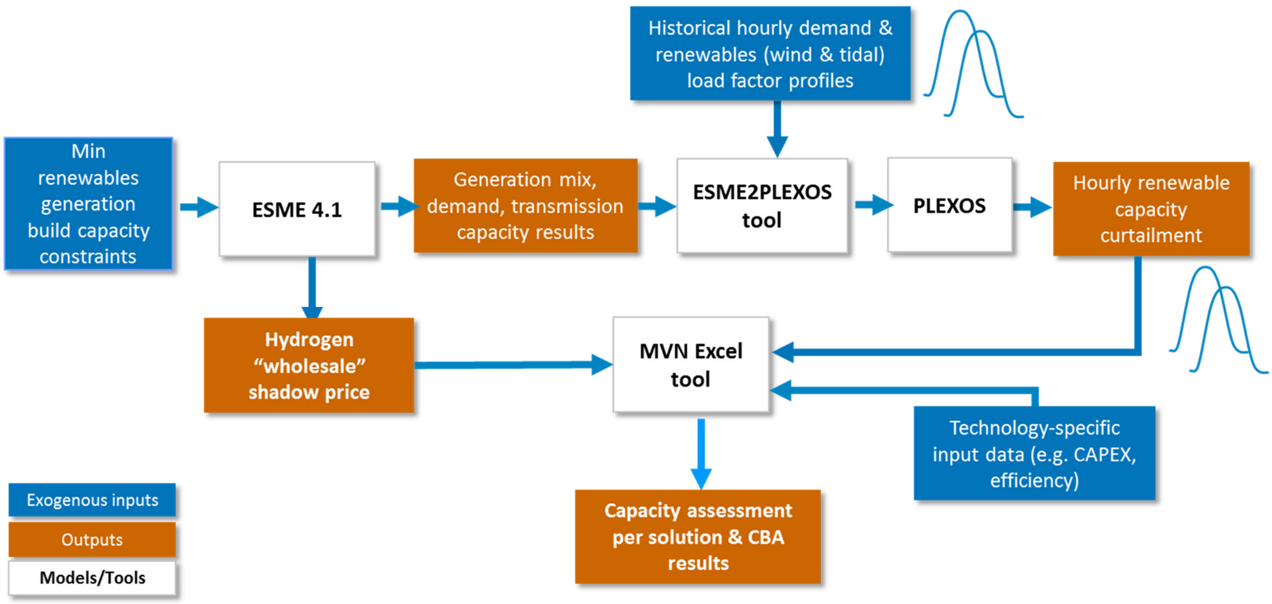

Figure 41-Methodology and Tools 4

Economic sizing of single vector counterfactual

For a fair comparison to multi vector P2G solutions for the curtailment of transmission-level renewables, the single vector counterfactual examined in this Case Study includes some means of alleviating curtailment, as opposed to a "do nothing" option. The starting point for the single vector option was assumed to be selective transmission reinforcement, combined with electricity storage (battery).

The process for sizing that single vector option is as follows:

- Using the hourly power flows for a whole year given by the initial PLEXOS results, the most congested transmission lines interconnecting all the UK regions can be identified, along with the total additional capacity required on each, for electrical power to flow freely from the generation centres to the centres of demand; this is determined by running the model in an unconstrained mode (where transmission capacity constraints are not imposed).
- Different sensible levels of selective reinforcement (e.g. reinforcing the, say, ten most congested lines by some percentage of the full reinforcement requirement) are then explored by re-running PLEXOS and checking the results on the residual hourly curtailment and total system generation cost.
- The model then attempts to resolve residual hourly curtailment level, testing some indicative scenarios of electrical battery storage located in the area where the bulk of that curtailment is observed (based on the hourly profiles obtained from the previous step). For this reason, a battery storage object is modelled in PLEXOS in the selected UK region and the model is re-run. This results in a new hourly generation dispatch and new power flows on the transmission lines.

- The system benefit is then evaluated based on the reduction of the total generation cost, driven by the reduction of low-cost generation spilling.
- The PLEXOS results on total generation cost and renewable curtailment from using different scenarios of the counterfactual solutions (i.e., the combined target reinforcement and storage) are then compared to the annualised capex of those technologies to select the most economically sensible counterfactual solution among the modelled options.

It should be highlighted that this does not involve a formal optimisation process for determining the optimal size and location of the single vector solution; single vector options tested capture possible reductions in the level of curtailment. The goal was to present a number of reasonable single vector cases, and gain a high-level understanding of the costs and benefits that each solution could provide.

Therefore, a detailed analysis of the transmission reinforcement selection and battery location and sizing would give further insight into the cost and technical implications of these single vector counterfactuals. Alternative options for dealing with curtailment also exist, such as DSR, but a detailed level of analysis of all single vector options is considered outside the scope of this study.

Cost-benefit analysis of solutions

After economically sensible sizes of the P2G technologies and single vector counterfactuals have been determined as above, the net benefit results for each case are fed into a CBA table comparing the competing technologies.

In summary; the diagnostic question in this Case Study is whether the multi vector options of electrolysis and methanation can offer a greater cost benefit to the system than the single vector counterfactuals examined, given the same conditions of hourly renewable generation surplus in the UK.

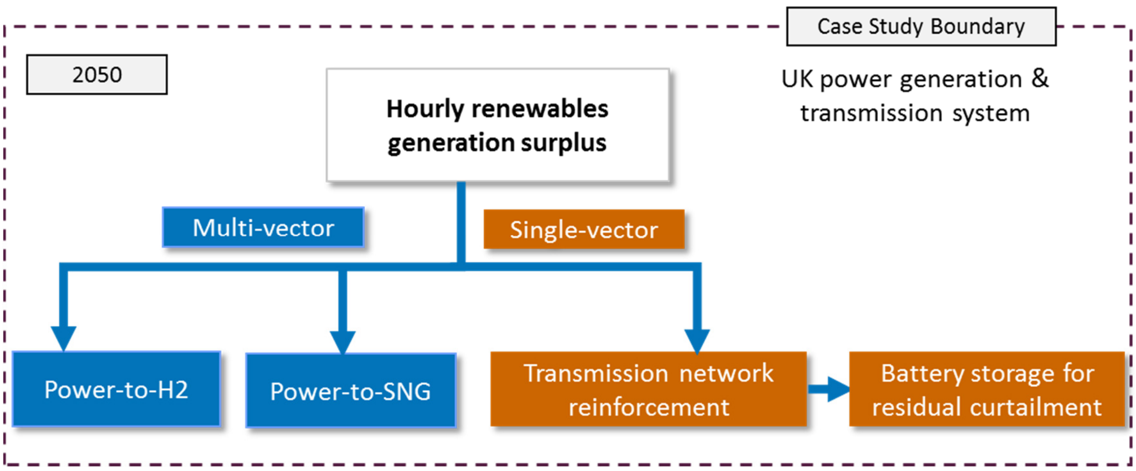

Figure 42-Case Study Set-Up

3.4.3 Scenario Definition and Assumptions

As described in the previous section, a number of different scenarios with increasing levels of renewable capacity were tested until one with significant amounts of curtailment economically was found, justifying the use of P2G.

The three scenarios modelled in ESME are shown in the following table. Note that these scenarios were generated by starting with the input assumptions in ESME V4.1 Ref Case and gradually increasing the minimum build capacity constraint for onshore and offshore wind in the model, whilst hydro and tidal capacities are the optimal values calculated by the ESME optimisation model in each scenario.

Table 48-ESME scenarios with -increasing renewables capacity

Generation capacity (GW)	ESME V4.1 Ref. Case	ESME Scenario 2 (medium)	ESME Scenario 3 (high)
Onshore Wind	13	20	20
Offshore Wind (fixed)	5	20	40
Offshore Wind (floating)	6	20	30
Hydro	3	3	3
Tidal	3	1	1
Total (GW)	**30**	**64**	**94**

The broader picture of the generation capacity mix in each of the above ESME scenarios is shown below, indicating that the increasing wind penetration levels lead to reduced nuclear and CCGT capacities.

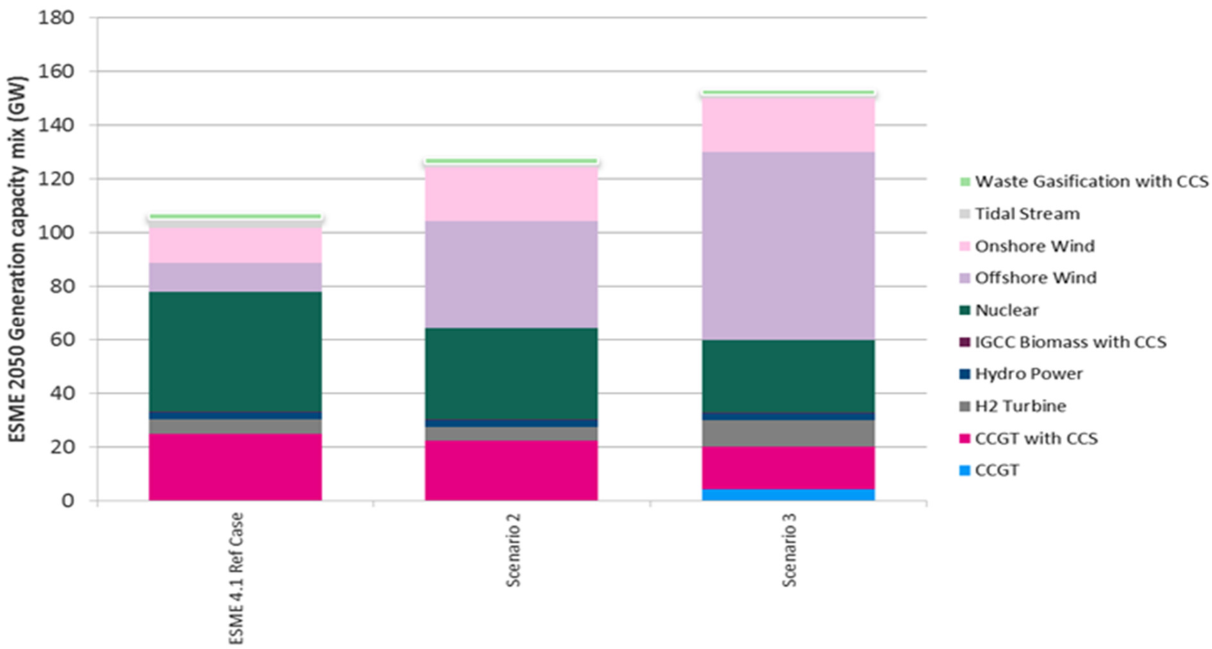

Figure 43- Generation technologies capacity mix per ESME scenario

For each of the three scenarios, we can determine

1. the economic level of the two P2G plants (electrolyser or methanator), given the ESME H_2 or natural gas shadow prices respectively
2. the duration curve of curtailment in each scenario.

The first step is to calculate the minimum load factor at which the marginal unit of capacity of the electrolyser (or the methanator) should operate, at which the levelised cost (£/MWh) is equal to the given H_2 (or natural gas respectively) shadow price (£/MWh). In the next step, the economic size of each assets is calculated given that minimum load factor and the renewables curtailment duration curve.

The applied methodology is explained in the following, through the example of electrolysis, though the same rationale was used to analyse the methanation case.

As a first step, the levelised cost of electrolysis (in H_2 terms) is calculated using the economic and technical input assumptions in 2050 which are based on the values found in ESME V4.1, shown in the following table. The only exception is the electrolysis efficiency, which takes the figure in the report for Leeds H21 project; significantly higher than the ESME value (80% as opposed to 69%).

The electrolyser is modelled as fully flexible, without output level and ramping constraints - this assumption is based on data published by NREL, who performed experimental tests on polymer electrolyte membrane (PEM) and alkaline electrolysers to evaluate their technical performance. Their results suggest that electrolysers can ramp up/down in less than a minute and that start up and shut down require only a few minutes (the latter was only tested on PEM electrolysers- in this study, alkaline electrolysers are assumed not to have material differences)[58]. The flexibility of PEM electrolysers is also highlighted in publicly available data from ITM Power[59]. Given the hourly granularity of our modelling, the assumption of full flexibility for electrolysis is considered valid for the purposes of this study.

Table 49-Electrolyser (power-to-H_2) technical and economic data (ESME 2050)

	Base	High	Low
Electrolyser capex (£/kWth)	701	947	526
Fixed O&M costs(£/kWth)	34		
Variable O&M costs (£/kWh)	0.001		
Economic lifetime (years)	20		
Technical lifetime (years)	20		
Cost of capital discount rate (%)	8		
Electrolyser efficiency (%)	80		

Given

- the duration curve of renewable curtailment from the ESME V4.1 Ref. case applied to 30GW of installed renewables (wind, hydro, tidal) capacity,
- a H_2 shadow price of £35/MWh, calculated as above, and
- the base 2050 technical and economic data for the electrolyser,

the minimum load factor that would be economically sensible to use is found to be 36%, as illustrated in the chart below.

[58] Novel Electrolyser Applications: Providing more than just hydrogen (NREL)

[59] NREL workshop 2014, ITM Power on *Clean Fuel, ITM Electrolysis at Forecourt Stations*

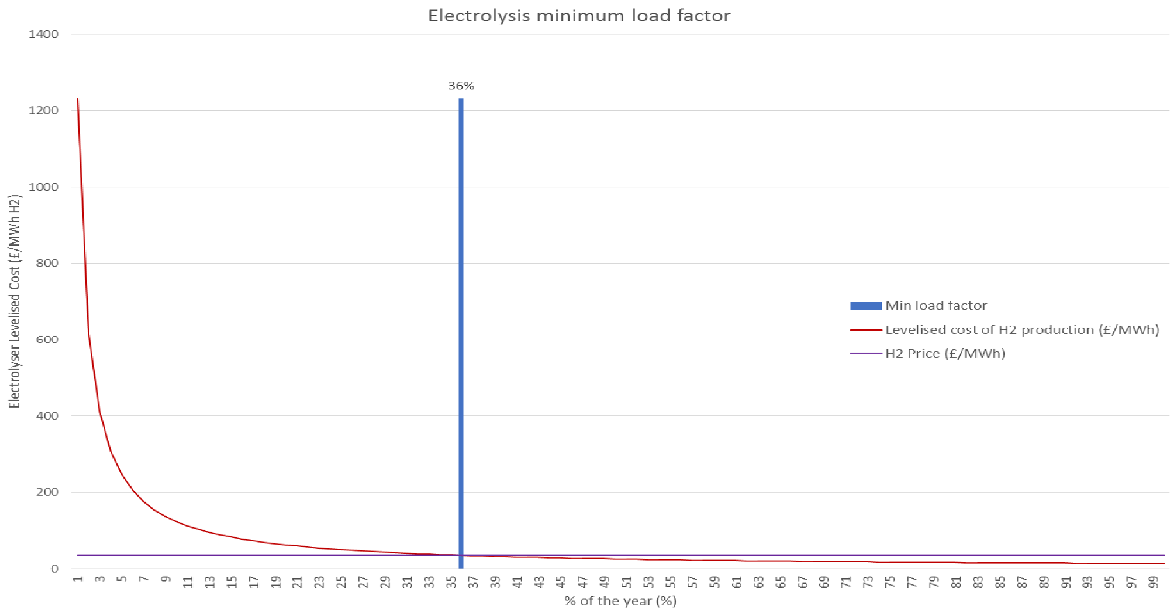

Figure 44- Min. economic load factor of electrolyser- ESME V4.1 Ref Case

Given the minimum load factor found in the first step and the duration curve of renewable energy curtailed in ESME Ref. 4.1 scenario, we calculate the economically sensible electrolyser capacity level. As seen in the following figure, there is no (zero) economic electrolyser size at the given renewable capacity and curtailment duration curve profile in this scenario; viable electrolysis requires higher curtailment levels.

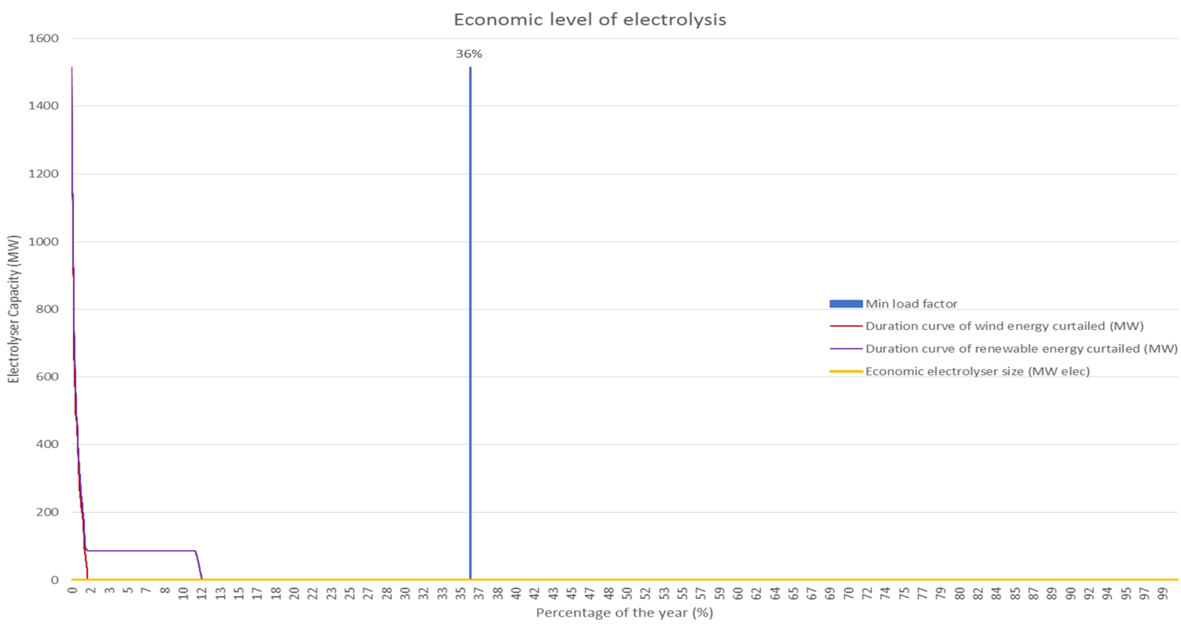

Figure 45-Economic size of electrolyser-ESME V4.1 Ref Case

The results from the process described above are shown in the following table for all three ESME scenarios modelled.

Table 50-Electrolysis Results under three ESME scenarios

	ESME V4.1 Ref. Case	ESME Scenario 2 (medium)	ESME Scenario 3 (high)
Electrolyser efficiency (%)	80	80	80
H_2 shadow price (£/MWh)	**35**	**31**	**28**
Energy curtailed (TWh)	0.1	8	23
Curtailment level (%)	0.1	4	7
Min. economic electrolyser load factor (%)	36	42	46
Economic electrolyser size (MW)	-	70	779
Renewable energy volume converted to H_2 (TWh)	-	0.4	5
Percentage of renewable energy surplus converted to H_2 (%)	0	5	21
Yearly H2 volume output (m^3)	0	84	1,106

The results show that as expected, curtailment levels increase with increasing levels of renewable energy capacity modelled in ESME. At the same time, H_2 shadow price drops, which can be attributed to the fact that the abundance of cheap renewable electricity influences other decisions made in ESME, which reduce the cost of H2 production. As a result, the minimum economic load factor of electrolyser for capex recovery increases. The results indicate that in Scenario 2, the economic level of electrolysis is quite low, at 70MW. This however significantly increases in Scenario 3, where a 779MW electrolyser array is economically viable and 21% of renewables surplus - which would otherwise be curtailed - is converted to H_2. The levelised cost vs load factor curve for electrolysis, as well as the curtailment duration curve corresponding to this scenario are shown in the following figures.

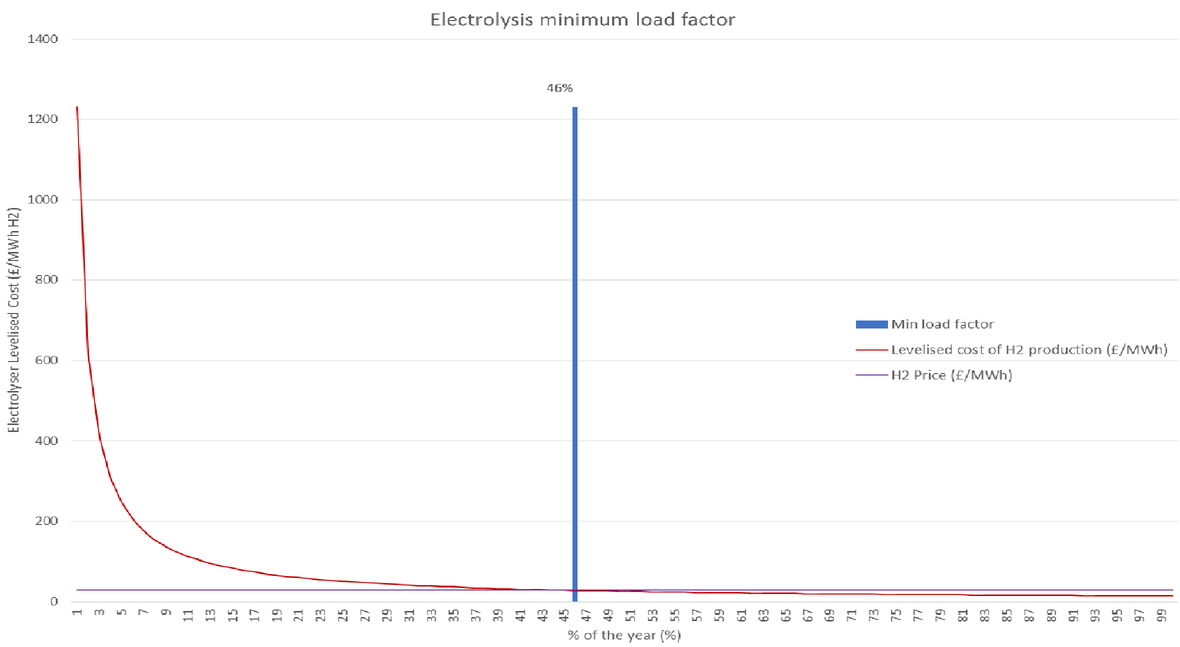

Figure 46-Minimum economic load factor of electrolyser- ESME Scenario 3 (High)

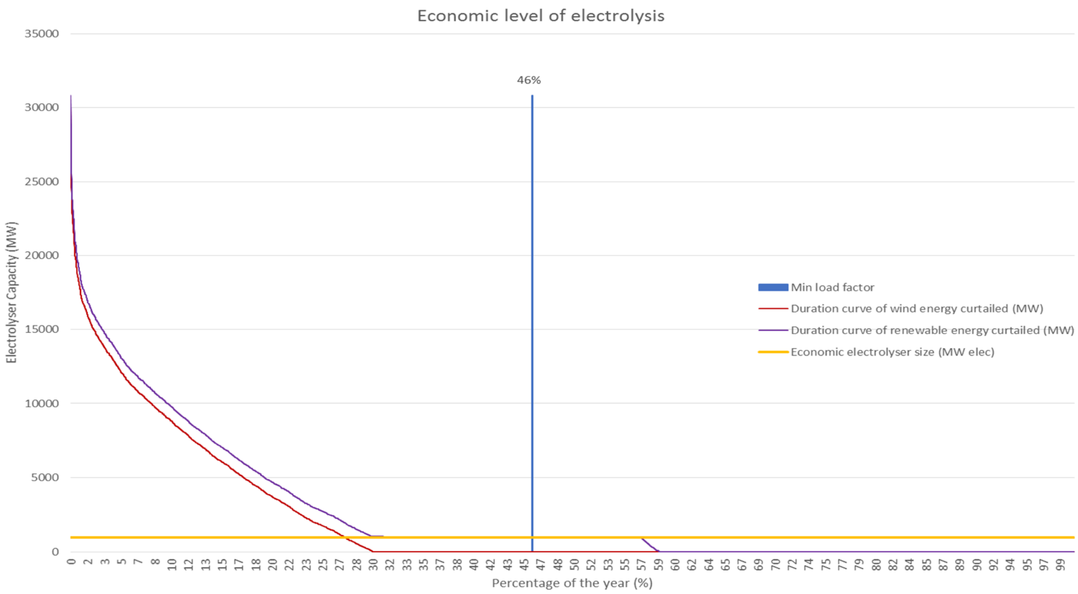

Figure 47- Economic size of electrolyser- ESME Scenario 3 (High)

Considering the above results, it has been decided that the Case Study analysis and comparison against the single vector counterfactual solution will be based on ESME High Renewables Scenario (Scenario 3). The same scenario is used as a base case in the methanation analysis; this process requires a subsequent catalytic methanation step, the technical characteristics of which are presented in the following section.

3.4.4 Case Study Analysis

Electrolysis (Multi Vector Configuration 1)

As explained in the previous section, the following analysis is focused on ESME High Renewables Scenario (Scenario 3).

Based on the methodology used to derive the economic level of electrolysis, the result is greatly dependent on the electrolyser's capex and the H_2sale price.

The economic mechanism dictating the price of H_2 injected into the grid in the future is unknown; currently, natural gas and biomethane are injected into the gas grid - the price of the former fluctuates, while the second benefits from feed-in tariffs. If in future, no similar mechanism support the price for blended H_2, one option is that natural gas will set the H_2 blending price. However, the methodology described in the previous section is agnostic to H_2 usage following its production, and the market to which it is sold.

Selling H_2 for transportation or industrial needs, as opposed to grid injection, could potentially give access to different prices and would have a direct impact on the economic sizing of electrolysers. Alternatively, if a wholesale H_2 market is established at national scale, the levelised cost of producing H_2 could set the wholesale price in all those markets.

The following table shows the sensitivity of these results to the price at which H_2 is sold and the electrolyser Capex.

To determine the impact of potential future H_2 prices, we have considered:

a. the ESME high scenario H_2 shadow price of £35/MWh, comparable to BEIS's high natural gas price scenario in 2040 (99 p/therm)[60]
b. the estimated H_2 sale price in the H21 Leeds project of £50/MWh, which corresponds to the cost of H_2 production and storage supplying the H_2 network envisaged in the Leeds area.[61].

Table 51- Sensitivity of results to capex and H_2 shadow price

	Base scenario (Scenario 3)	Low ESME Capex	High H_2 shadow price (ESME Ref. Case)	Leeds H21 H_2 sale price
Total capex (£/kWth)	**701**	**526**	701	701
Electrolyser efficiency (%)	80	80	80	80
H_2 price (£/MWh)	**28**	28	**35**	**50**
Energy curtailed (TWh)	23	23	23	23
Curtailment level (%)	7	7	7	7
Min. economic electrolyser load factor (%)	46	38	30	25
Economic electrolyser size (MW)	779	779	779	2,219
Renewable energy volume converted to H_2 (TWh)	5	5	5	9
Percentage of renewable energy surplus converted to H_2 (%)	21	21	21	40
Yearly H_2 volume output (MCM)	1,106	1,106	1,106	2,086

Both lower capex figures and higher wholesale H_2 prices reduce the plant lifetime breakeven load factor. Nonetheless, because the specific duration curve of curtailment that corresponds to Scenario 3 is "blocky", a lower minimum load factor might not necessarily lead to a higher size of electrolysis. For example, despite the low capex and high shadow price scenarios both requiring a lower load factor, there is no benefit in terms of size of electrolysis or H_2 output. On the other hand, a benefit is observed when the shadow price is increased to £50/MWh, with 40% of otherwise curtailed renewables being converted to H_2.

It should be highlighted that the benefit of electrolysis to the system is quantified based on the revenues from the H_2 sales at the wholesale price. Therefore, in this multi vector configuration, the net benefit is the difference between the annualised electrolysis capex and the H_2 sales revenues, a figure which we compare against the single vector solution in section on Comparison of Single and Multi Vector Options.

[60] BEIS 2015 Fossil Fuel Price Assumptions

[61] The total hydrogen sale price quoted in the Leeds H21 project report is £76/MWh, which however includes billing, environmental levies and transmission costs. Since a proxy for the wholesale rather than retail price of hydrogen is needed for this analysis, these costs have been excluded.

As the Case Study boundary includes the electricity generation and transmission system in the UK only, H_2 shadow price has been fixed throughout this offline analysis, under the assumption that H_2 production through electrolysis of renewables surplus generation would not have a material impact on the broader ESME system.

Indeed, the total level of H_2 produced in ESME Scenario 3 is 10.2 TWh, with the largest part produced via biomass gasification (with CCS). The H_2 produced via electrolysis in our analysis is therefore 38% of the total H_2 produced in the wider system under Base and Low capex scenarios. This assumption is challenged in the high H_2 price scenarios, where production reaches 73% of the total ESME H_2 production. Despite the significant volume of H_2 produced via electrolysis in this analysis, the merit-order of H_2 production in ESME is not affected, since the electrolyser has been sized such that its H_2 production is less expensive than the marginal (most expensive) technology in ESME. This could be explored further in any future full system analysis.

This case study assessed the potential for to electrolysers to absorb renewable oversupply that would otherwise be curtailed; the "blockiness" of the duration curve of this generation means that increasing hydrogen price by 25%, and reducing capex by the same factor, lead to no increase in the size or output of the electrolyser. An approximately 75% increase in hydrogen price, however, leads almost to a trebling in electrolyser size, such that 40% of UK renewables surplus is used to generate H_2.

Methanation (Multi vector configuration 2)

This section presents the results of methanation as a P2G solution, i.e., the conversion of electricity to H_2 via electrolysis followed by a subsequent methanation step to produce synthetic methane (SNG), which can then be injected into the natural gas grid. Using the methodology above, an economic level of methanation has been derived under the Base Scenario 3 described in the previous section.

A key difference between electrolysis and methanation (apart from the further efficiency loss and capex increase) is that methanation requires CO_2 to convert the electrolysis-produced H_2 to methane (SNG). There are various sources of CO_2, depending on which option is chosen the system carbon cost varies.

The following scenarios for carbon feed have been assumed:

Case A - Zero Carbon Cost:

- CO_2 is taken from a CCS facility, and the SNG produced and injected into the gas grid displaces an equivalent amount of natural gas, or CO_2 is taken from a fossil power plant without CCS (e.g. the CCGT built in ESME Scenario 3) and the SNG injected into the gas grid does not displace any natural gas. In these cases, methanation does not change carbon emissions. Therefore, no additional system carbon cost is incurred by the methanator.

Case B - Negative Carbon Cost:

CO_2 is taken from a fossil power plant without CCS, which would otherwise be emitted, while the SNG produced and injected into the gas grid displaces the equivalent amount of natural gas in the system. In this case, methanation provides a net reduction of carbon emissions at a system level and therefore has a negative cost given by the negative of the carbon price.

Case C - Positive Carbon Cost:

CO_2 is taken from a CCS facility, while the SNG injected into the gas grid does not displace any natural gas in the system. In this case, there is a net increase of carbon emissions at a system level and therefore there is a positive cost equal to the carbon price.

As the electrolysis analysis indicated that the capital cost and H_2 price can affect the results, the sensitivity to the respective parameters for methanators (capital cost and gas price) has been similarly assessed.

The following table shows the economic and technical data used to model the methanation case. ESME V4.1 does not include economic and technical information for the additional equipment required for methanogenesis, i.e., the methanation reactor used for the methanation step following the production of H_2 via electrolysis.

Assumptions were instead taken from a study on P2G solutions by ENEA Consulting[62], and are shown in Table 52 below. As the electrolysis efficiency was assumed to be 80%, the methanation efficiency is fixed at 64%, representing a 20% loss. This efficiency loss, as well as the methanator's carbon consumption per unit of gas produced are also based on the ENEA Consulting P2G study.

Table 52- Methanation (power-to-SNG) technical and economic data

	Base	High	Low
capex (£/kWth)	1,150	1,553	863
Fixed O&M costs (% of methanation reactor Capex)	7.5		
Variable O&M costs (£/kWh)	0.001		
Economic lifetime (years)	20		
Technical lifetime (years)	20		
Cost of capital discount rate (%)	8		
Methanation (Power-to-Gas) efficiency (%)	64		
CO_2 consumption (m^3 CO_2/m^3 SNG)	1		

The following table shows the economic level of methanation results under the ESME Scenario 3 for the three different cases of carbon cost incurred for the methanator, as described above. The shadow price of carbon in 2050 in this scenario is very high, at £545/tonne.

In Case A, when the carbon cost to the methanator is zero; renewable curtailment levels are insufficient to ensure a minimum load factor of 80%, which is required for capex recovery within the 20 year lifetime.

In Case C, no load factor ensures lifetime capex recovery, given the positive CO_2 cost and the gas price.

However, the results in Case B under a negative carbon cost suggest that methanation has a strong potential where carbon prices are very high, converting 59% of renewable energy surplus to SNG. As mentioned earlier, this would only be possible if:

1. the amount of SNG injected into the grid displaced the same amount of natural gas from other sources and
2. the CO_2 is taken from a fossil plant without CCS.

The most obvious source would be the carbon emissions from the CCGT plants without CCS - however these represent only a small percentage of the capacity mix in ESME Scenario 3 in 2050, since most of that capacity mix consists of technologies which are either low-carbon, renewable, or equipped with CCS.

[62] "The potential of Power-to-Gas", ENEA consulting, January 2016

Table 53-Base scenario methanation results under three CO_2 source cases (A, B, C)

	Base scenario (Scenario 3) CO_2 Case A	Base scenario (Scenario 3) - CO_2 Case B	Base scenario (Scenario 3) CO_2 Case C
Total capex (£/MWth)	1150	1150	1150
Methanation total efficiency (%)	64	64	64
Gas price (£/MWh)	28	28	28
CO_2 cost (£/tonne)	**0**	**-545**	**545**
Energy curtailed (TWh)	23	23	23
Curtailment level (%)	7	7	7
Minimum economic methanator load factor (%)	80	19	Not available
Economic methanator size (MW)	0	3,292	0
Renewable energy volume converted to SNG (TWh)	0	14	0
Percentage of renewable energy surplus converted to SNG (%)	0	59	0
Yearly SNG volume output (MCM)	0	798	0

The sensitivity of the above results to the methanation Capex, gas price as well as carbon cost is illustrated in the following tables for the CO_2 cases A and C.

Table 54-Sensitivity of methanation results to capex and gas price for CO_2 Case A

	Base scenario (Scenario 3)- 40% lower Capex	Base scenario (Scenario 3) 40% higher gas sale price
Total capex (£/MWth)	**690**	1150
Methanation total efficiency (%)	64	64
Gas price (£/MWh)	28	**39**
CO_2 cost (£/tonne)	0	0
Energy curtailed (TWh)	23	23
Curtailment level (%)	7	7
Min. economic methanator load factor (%)	54	56
Economic methanator size (MW)	618	618
Renewable energy volume converted to SNG (TWh)	5	5
Percentage of renewable energy surplus converted to SNG (%)	21	21
Yearly SNG volume output (MCM)	282	282

Table 55-Sensitivity of methanation results to capex and gas price for CO_2 Case C

	Base scenario (Scenario 3)- 40% lower Capex	Base scenario (Scenario 3)- 40% higher gas sale price	Base scenario (Scenario 3)- low carbon price & 40% higher gas sale price & 40% lower Capex
Total capex (£/MWth)	**690**	1150	**690**
Methanation total efficiency (%)	64	64	64
Gas price (£/MWh)	28	**39**	**39**
CO_2 cost (£/tonne)	545	545	**50**
Energy curtailed (TWh)	23	23	23
Curtailment level (%)	7	7	7
Min. economic methanator load factor (%)	Not available	Not available	48
Economic methanator size (MW)	0	0	621
Renewable energy volume converted to SNG (TWh)	0	0	5
Percentage of renewable energy surplus converted to SNG (%)	0	0	21
Yearly SNG volume output (MCM)	0	0	284

The sensitivity results indicate that at zero CO_2 price (case A), a capex reduction or an increase in the SNG price would increase the attractiveness of investing in methanation. The benefit leads to non-zero output at a 40% capex reduction or a 40% gas price increase, which both lead to a conversion of 21% of the curtailed renewable surplus into SNG.

For the case where CO_2 price is positive (case C), to achieve a similar level of methanation built in the system as for case A, the combination of reducing the carbon price to £50/tonne, reducing the capex by 40% and increasing the gas price by 40% was required. If only one of these changes is made, there is no economic load factor at which the methanator recovers its capital and operational costs within 20 years.

Under the Base Case scenario which corresponds to high penetration of renewables in 2050; in which carbon is priced at £545/tonne, and gas at £28/MWh, the methanation case is attractive where it leads to net carbon reduction in the system - removing CO_2 that would otherwise be emitted (Case B).

As methanation involves further efficiency losses, electrolysis and injection is a viable only where it leads to a net decrease in carbon emissions. Smaller carbon neutral or carbon emitting facilities might also create value if the gas price rose or the capital costs fell substantially, or in the latter case, both – accompanied by a much-reduced carbon price.

Selective Reinforcement and Electricity Storage (Single Vector Counterfactual)

As part of the curtailment is caused by limited transmission capacity between UK regions, local transmission grid reinforcement could reduce the renewable energy spill. However, local grid reinforcement will not alleviate the system-level generation surplus caused by national supply exceeding demand at particular times.

A range of solutions might reduce reinforcement such as electricity storage, demand side flexibility as well as the expansion of UK interconnection to neighbouring markets. However, interconnector capacity to neighbouring countries is kept fixed in this study, (the assumption made in ESME itself), and DSR is not examined for simplicity. We have instead investigated the potential of using battery storage to alleviate residual curtailment following local grid reinforcement.

Starting with the hourly power flows on transmission boundaries given by PLEXOS for ESME Scenario 3, we identify some level of constraint on all boundaries; reinforcing all of them to remove all constraints is not an economically viable option. In practice, it is envisaged that the Transmission System Operator would reinforce a selected number of lines, perhaps those requiring the most additional capacity.

To understand a practical economic level of potential reinforcement, we analysed the impact of reinforcing the three lines requiring the largest scale of reinforcement, at increasing levels: 10% (5GW), 25% (13GW), 50% (25 GW), 75% (38 GW) and 100% (50 GW).

The economic data used in the appraisal of the single vector technologies above against the multi vector solution, i.e. onshore transmission lines and Li-On batteries, are taken from ESME V4.1 and shown below.

Table 56-Onshore transmission line and battery economic data (ESME 2050)

	Transmission Line	Li-On Battery
capex (transmission) (£/kW/km)	0.92	-
capex (capacity) (£/kW)	-	271
capex (energy) (£/kWh)	-	267
Economic lifetime (years)	50	15
Cost of capital discount rate (%)	8	8

The single vector counterfactual system benefit comprises savings in the total UK generation dispatch cost, achieved by exploiting low cost renewable generation which would otherwise be spilled; the net system benefit is given by the total generation savings less the annualised investment cost (Capex).

The results for the five different reinforcement scenarios are shown in the following figure; curtailment levels are improved with increasing levels of reinforcement, while the savings in total UK generation cost also improve.

However, these savings come at significant investment cost, with the overall net system benefit gradually decreasing; the most economically sensible solution amongst the ones described, is the 10% (5GW) reinforcement scenario which has the highest net system benefit.

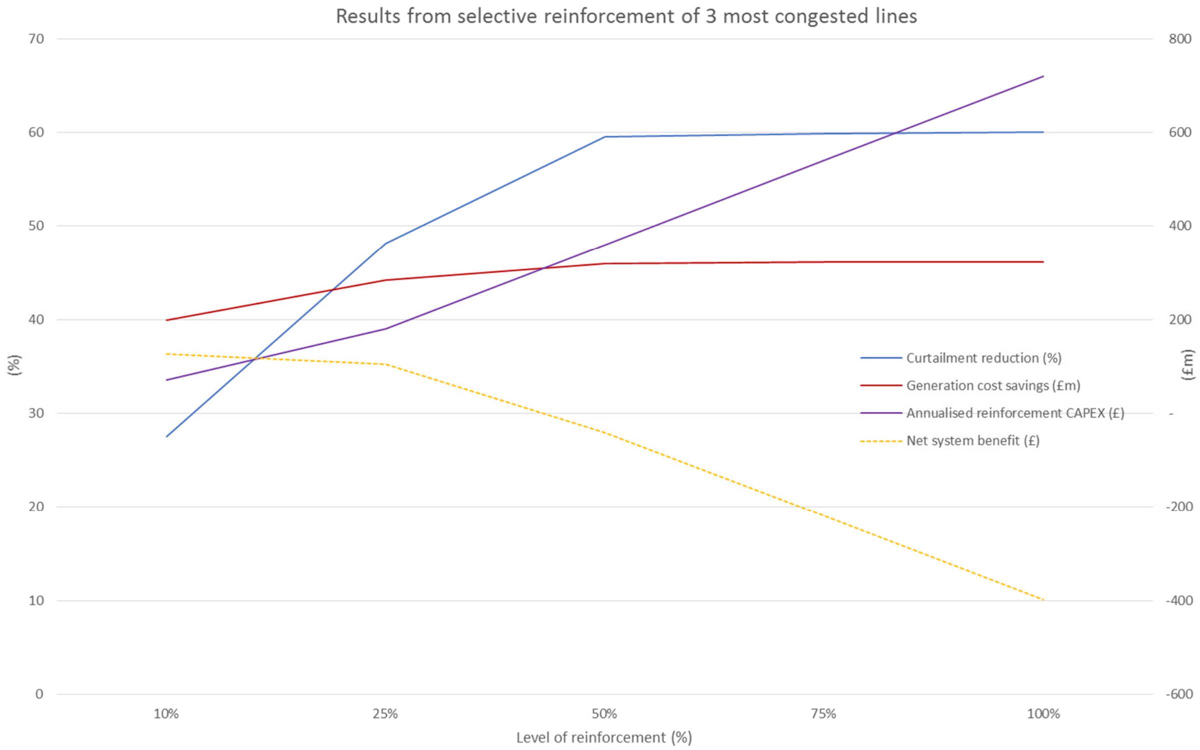

Figure 48-Results from selective transmission reinforcement

The bulk of residual renewable spill following network reinforcement was found to be in Scottish offshore wind - at Dogger Bank wind farm.

Offshore transmission lines connecting generation to the onshore grid are sized for maximum offshore capacity in each ESME solution. However, due to constrained capacity in other parts of the networks, a significant part of that offshore generation may still be curtailed.

To determine the economic attractiveness of using a battery to alleviate this, we took the 50% reinforcement scenario of the three transmission lines as a starting point, and tested different sizes of batteries located in Scotland: 5GW/1hr, 5GW/2h, 10GW/1h, and 15GW/1h- (these figures are based on the observed hourly profile of residual offshore wind curtailment in Scotland).

The results are presented in the following chart; despite curtailment spill going down and total generation cost savings increasing slightly as battery size increases, the high battery capex leads to significant net system cost increases which get larger with battery size. The net system benefit is negative in all cases.

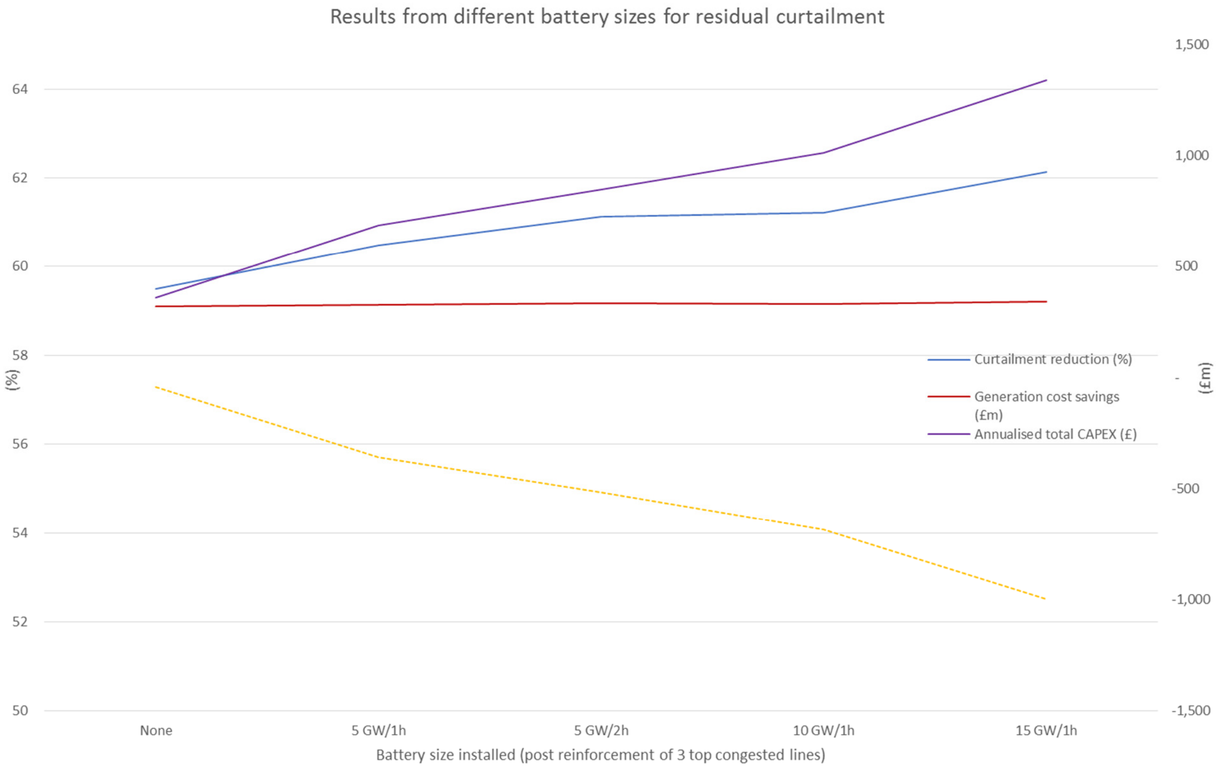

Figure 49- Results from different battery sizes for residual curtailment

From above, we conclude that installing a battery purely as a means of alleviating the residual curtailment is not an economically viable option; without other drivers for installing large-scale batteries, it is envisaged that selective reinforcement represents the main single vector counterfactual.

> Limited upgrade of constrained transmission assets is beneficial to the system but batteries are never cost effective as a means of mitigating curtailed generation.

Comparison of Single and Multi Vector Options

Electrolysis

The following table compares the results for the multi vector electrolysis option and the single vector selective reinforcement solution from a system cost-benefit perspective; the “do nothing” option has also been included for comparison.

As well as the Base Case scenario for the multi vector option, the results for some examples of sensitivity scenarios examined above are also included in the same table, to illustrate:

1. how the total system cost varies with H_2 price and electrolyser Capex
2. the impact each solution has on curtailment reduction.

The table shows:

1. the capital and operational costs,
2. the revenues from H_2 production from electrolysis
3. the system generation dispatch cost associated with each solution,

These are used to calculate a total system cost, enabling us to compare the benefits of each case. The residual curtailment in each scenario is also provided. In the Base Case scenario, the single vector solution of selective reinforcement seems to lead to lower total system cost and greater curtailment reduction compared to electrolysis. Although the Base Case scenario (ESME Scenario 3) has a high penetration of renewables (90GW in 2050), leading to the curtailment of 23TWh zero-cost electricity, the economics of electrolysis as a means of resolving system level oversupply appear challenging; this can be attributed to the low H_2 compared to electricity price, the capital costs and the shape of the curtailment duration curve.

Sensitivities

Higher H_2 prices increase the size of electrolyser built - its capital costs can be paid back at a lower annual load factor given the same curtailment duration curve. Whilst capital and operational costs increase with greater levels of electrolysis capacity, the system revenues increase more sharply. In this way, the net effect is that the total system cost reduces, reaching levels which are comparable to, or even lower than, the single vector option total system cost while also reducing residual curtailment in the system.

The reduction in electrolyser capex has a similar effect on the total system cost by either increasing the electrolyser size or reducing the capital costs; a combination of H_2 price increase and reduction of capex could create significant potential for electrolysis, making it more favourable than its single vector competitor. Indeed, levels of grid reinforcement above 10% can reduce curtailment at a cost which exceeds the generation cost savings; to reduce residual curtailment to the 3% level, the three top most-congested transmission lines must be reinforced to 100% of required capacity, which comes at a far greater cost that in the multi vector scenario where the Leeds H21 H_2 price and the low scenario electrolyser capex value are used.

Under the Base Case scenario, transmission reinforcement is preferred to electrolysis; electrolysis could however become viable and successfully compete with reinforcement, provided the value of H_2 generated reaches levels similar to the value quoted in Leeds H21 project. If capex is also reduced, electrolysis begins to offer material benefits compared to the single vector case, both in terms of total system cost and curtailment reduction.

Table 57-CBA table for electrolysis (MV) vs transmission reinforcement (SV)

	Multi Vector (Electrolysis)				**"Do-Nothing"**	**Single Vector (reinforcement of top 3 most congested lines)**	
	Base Case	Leeds H21 H2 price	Low Capex	Leeds H21 H2 price & Low Capex		Base Case (10%)	100%
H2 price (£/MWh)	28	50	28	50	n/a	n/a	n/a
Electrolyser capex (£/kW)	701	701	526	526	n/a	n/a	n/a
Electrolyser size (MW)	779	2,219	779	2,783	n/a	n/a	n/a
Annualised capex & operational costs (£m)	88	247	73	319	0	72	720
H_2 revenues (£m)	-110	-370	-110	-494	n/a	n/a	n/a
Generation costs (£m)	6,025	6,025	6,025	6,025	6,025	5,827	5,702
Total system cost (£m)	**6,003**	**5,902**	**5,988**	**5,850**	**6,025**	**5,899**	**6,422**
Residual curtailment	**6%**	**4%**	**6%**	**3%**	**7%**	**5%**	**3%**

Methanation

For the case of methanation, the economic level under the Base Case was derived separately for the three carbon cost cases, but only Case B (where carbon cost was negative) was an economically viable option – in this case a significant part of renewable surplus is converted to H_2.

The CBA table comparing the single vector results to methanation Case B is given below, confirming that in the case where methanation offers carbon benefits, it is more cost-competitive than selective reinforcement, leading to significantly lower system cost and residual curtailment.

However, as discussed earlier, the underlying assumption for Case B is that the amount of SNG injected into the grid displaces the same amount of natural gas from other sources, while the CO_2 comes from CCGT plants without CCS - this represents only a small percentage of the capacity mix in ESME Scenario 3 in 2050 however, since most of that capacity mix consists of technologies which are either low-carbon, renewable technologies or are equipped with CCS. Therefore, while it appears, promising, Case B has limited potential in a future low-carbon energy system.

The results for the scenarios where carbon cost is either zero (Case A) or negative (Case C), have been omitted; even significant methanation capex reduction or increase of gas (SNG) price lead only to slight improvements in total system cost compared to the “do nothing” option.

Table 58- CBA table for methanation (MV) vs transmission reinforcement (SV)

	Multi Vector (Methanation)	**“Do-Nothing”**	**Single Vector (Selective transmission reinforcement of top 3 most congested lines)**	
	Case B (negative carbon cost)		Base Case (10%)	100%
SNG price (£/MWh)	28	n/a	n/a	n/a
Methanator capex (£/kW)	1150	n/a	n/a	n/a
Methanation size (MW)	3,292	n/a	n/a	n/a
Annualised capex & operational costs (£m)	630	0	72	720
SNG revenues (£m)	-246	n/a	n/a	n/a
Carbon costs (£m)	-785	0	n/a	n/a
Generation costs (£m)	6,025	6,025	5,827	5,702
Total system cost (£m)	**5,624**	**6,025**	**5,899**	**6,422**
Residual curtailment	**3%**	**7%**	**5%**	**3%**

Electrolysis, methanation with captured carbon, and injection competes with single vector reinforcement, at carbon prices of £545/tonne however, little unabated CO_2 is likely to be available. In the absence of this configuration, single vector solutions outperform their multi vector counterparts.

Additional Revenue Streams for Electrolysers

The key conclusion from the analysis above is that, in the Base Case scenario modelled, electrolysis is not a competitive option compared to transmission reinforcement, due to its high capital costs against the relatively low hydrogen value (as given by the ESME shadow price). The analysis and CBA results presented so far focus on using electrolysers, and sizing them to, times of renewable curtailment; consuming zero-cost surplus electricity that would otherwise be spilled. However, electrolysers can increase their revenues thanks to their flexibility and rapid response, which make them candidates for ancillary service provision to the grid. An operating strategy combining different revenue streams could increase the value, and hence competitiveness, of electrolysis in the energy system.

Different technologies can offer a range of ancillary services, each of which has a different response time and duration requirements; we now investigate which services electrolysis might provide.

NREL performed several experimental tests on small scale (around 40kW) PEM and alkaline electrolysers to determine whether they meet the operational requirements for ancillary service provision[63]. In addition, as part of the Aberdeen H2 Project, SSE published a report on the impact of electrolysis on distribution networks[64], and reviewing the NREL findings.

We note the electrolysers envisaged in this case study are larger than those tested by NREL, and are assumed to be connected to the transmission, rather than distribution, network. For this study, we assume the scale of the technology has no material impact on its technical performance.

The table below shows the technical performance results for the electrolysers tested by NREL; their results suggest that electrolysers are quite flexible in ramping up/down from their minimum stable level (MSL) to full load and vice versa, which they can do within around a second. However, PEM electrolysers take several minutes for cold start-up or shut-down (idle to full power or vice versa). Alkaline electrolysers' performance at start up and shut-down was not tested by NREL; in the absence of data we assume here that they have a similar behaviour to PEM technology.

Table 59- Technical characteristics of electrolysis technologies

Electrolyser type	MSL	Start-up/shut down time (cold to/from full power)	Ramp up/down time (MSL to/from full load)
Alkaline	~25%	Not tested	~1 sec
PEM	~25%	~7 mins (up) ~1 min (down)	~ 1sec

Ancillary services, can be divided in two main categories: frequency response and reserve services, and frequency response services can be further classified by their response time and duration. In the event of a frequency deviation, frequency containment[65] service focuses on limiting the rate of change of frequency and bringing it into permissible operating limits. Therefore, participating technologies must act fast - within seconds - but the duration of the service is quite short (on the order of several seconds).

[63]"Novel Electrolyser Applications: Providing More Than Hydrogen", NREL, 2014

[64] "Impact of Electrolysers on the network, Part of Aberdeen Hydrogen Project", SSE

[65] The ENTSOE classification of frequency containment (primary), frequency replacement (secondary) and reserve replacement (tertiary) is a more comprehensive but generic classification of balancing services in the electricity market. Each of those services can be approximately mapped to existing ancillary services in the current GB market which the TSO uses to balance the electricity system along with the BM and other commercial products

Frequency replacement is the secondary response which aims at bringing system frequency back to its operating point, and can be thought of as a restorative response. This also requires the participant to respond within seconds but the response must typically be sustained for several minutes.

Reserve replacement services exist deal with unforeseen increases of demand, or lack of generation, and their timescales are slower than for frequency response services. These broad categories of balancing services, along with their relevance to the UK market and time requirements are shown in the following table.

Table 60- Main balancing services types

Balancing Service Type	Relevance to current GB market	Response time	Response duration
Frequency containment[66]	Approximately maps to Primary and High Frequency response service - part of FFR product	~10secs	~seconds
Frequency replacement	Approximately maps to Secondary response service- part of FFR product	~30secs	~minutes
Reserves (tertiary control)	Approximately maps to FR, STOR and Demand Turn-Up services	~2mins(FR), ~20mins(STOR), ~10mins (Demand Turn Up)	~minutes-hours

As electrolysers can ramp up and down quite fast (on timescales of around 1 second), when they are already operating (not cold), they could provide both frequency containment (primary) and replacement (secondary); among the highest value ancillary services procured by National Grid. As they can vary their output in proportion to the system frequency deviation, electrolyser response can be classified as dynamic.

However, since their primary purpose as envisaged here is to convert excess renewable generation into H_2 at times of transmission network bottlenecks or national demand-supply mismatch, they likely operate mainly at times of renewable (hydro or wind power) curtailment. At these times, electrolysers can only provide Low Primary or Secondary response - by reducing their electricity consumption - and the need for such services is unlikely during times of curtailment - when system has more generation than demand. This does not therefore appear a promising scenario.

For simplicity, we therefore assume that electrolysers only provide ancillary services outside times of curtailment; in the Base Case scenario presented in the previous sections, a 779MW electrolyser array operates 46% of the year at full load, and another 13% at part load. Thus, the electrolyser would be available for balancing services (other than curtailment management) around 40% of the time. The efficiency of the electrolyser is assumed to be 80% and for simplicity, operational costs are ignored in the following calculations.

During those times, the electrolyser can:

[66] "Profiting from Demand Side Response", National Grid, Power Responsive, 2016

a. Participate in the NG Demand Turn Up (DTU) service provision[67]; turning on to increase demand when there is excess energy on the system (but no renewables curtailment). This is the only service whose requirements existing electrolysers meet from cold start; FFR services require a response within seconds, while starting electrolysis takes several minutes. Fast Reserve (FR) requires a response within two minutes, and STOR requires demand reduction which the electrolyser cannot offer without being in operation. Demand Turn-up providers are currently paid a small availability fee (around £1.5/MW/h), and a utilisation fee when they are asked to run (currently at £60-75/MWh). There are currently two availability windows (for base and peak months) corresponding to a total of approximately 890 hours per year.

   It should be highlighted that some of these hours will likely coincide with times of curtailment at which the electrolyser is not idle; however - to give a sense of the scale of revenues that such as service can offer (and since the availability fee is negligible compared to the utilisation fee of this service) - we consider the limit case in which the electrolyser is available for DTU for all those hours.

   It is difficult to predict the number of hours, and the capacity, of service requested by the system operator – here we assume the asset makes itself available all 890 hrs/year and called upon 10% of its availability time offering its full capacity as demand. In this case, annual revenues increase by around £5m, based on:

   - the cost of electricity (£47/MWh)
   - the revenues from H_2 sales (£28/MWh)
   - the availability fee (£1.5/MW/h)
   - the utilisation fee (£67.5/MWh)

   For context, at 30% turn up provision, its DTU revenues would reach £12m.

b. Operate at MSL (25% full rating) during the 40% idle time, allowing it to provide High Frequency Response at times of low demand and high generation in the system (excluding times of renewables curtailment). In the current market, High Response is offered separately by some participants, and the average combined availability and nomination fee offered historically totals £13/MW/h (significantly lower than for other FFR services, such as the combined PSH and PS).

   To give a sense of revenues for this service, we assume the electrolyser is available to the system operator during the night summer hours (April-September, 7pm-7am) corresponding approximately to 25% of the year. A fraction of this time will coincide with periods of curtailment at which the electrolyser will be operating at full load; for this analysis we assume curtailment times comprise to two-fifths of the 25% of night summer hours (10% of the year – we assume also that these times can be forecast with the required degree of precision). The electrolyser can then contract for High Response during the remaining summer night hours (15% of the year), on the basis that it will be operating at MSL, and can thus respond to High Frequency Response events if requested.

   In this scenario, it earns the availability fee while operating at its MSL, consuming electricity at an average price of around £40/MWh (the average overnight price in summer months) and producing H_2 at £28/MWh; if it is called upon to increase its consumption to full load 10% of that availability time, total profit will be around £3m. Note that the electrolyser is remunerated for the headroom it offers to the system operator. As the utilisation factor increases however, revenues reduce significantly; profits drop to £500k at 30% of availability time, and becomes negative beyond 35%, as the cost of purchasing electricity exceeds the revenues from availability fees and H_2 sales.

[67] *Demand Side Opportunities*, National Grid, Power Responsive

It should be noted that DTU (option (a)) and High Response cannot be contracted at the same time; the system operator only allows the asset to declare availability to DTU when it declares availability for other balancing services.

c. Operate at 62.5% - the middle point between MSL and full load, allowing provision of Primary and Secondary frequency response (at times of high system demand and low generation) as well as High Frequency Response (when generation exceeds demand), offering the same headroom in both directions (37.5% of its capacity). FFR PSH is one of the most valuable products, and has historically received a fee of between £25/MW/h and £50/MW/h.

   While the electricity grid is more likely to need demand reduction during the 40% of the year that the electrolyser is not absorbing curtailment, running electrolysers at 62.5% output is found to only be profitable if the availability fee exceeds £41/MW/h. If the availability fee (paid on the available 37.5% plant capacity) exceeds this value, the electrolyser overcomes the loss from purchasing electricity (at £47/MWh average) and selling lower-value H_2 (at £28/MWh average). For context, at a service fee of £50/MW/h, profits amount to £12m annually (if the electrolyser is available for PSH the entire 40% of the year when it is not absorbing curtailment)[68].

From these high-level calculations, based on the ancillary service values in the current UK market, the maximum additional revenues that an electrolyser might access through ancillary service provision can be up to several millions per year. We recognise however that the ancillary services market is likely to evolve in future, and that even if the market is similar to the present one, a detailed analysis would be required to determine the contracting strategies that an electrolyser would best adopt to maximize profits.

Based on the CBA results in Table 57, this additional revenue is insufficient to bridge the gap between the single and multi vector total system costs in the Base Case scenario. A higher H_2 price or reduction in electrolyser capex remain the primary ways of improving the competitiveness of electrolysis (an increase of H_2 price would increase ancillary service revenues, as they reduce the difference between the price of electricity consumed and that of the H_2 generated.

In addition to supporting the electrical system, electrolysis might be used in future H_2 networks to match demand and supply, both on a regular basis or during periods of severe stress; by altering their H_2 generation profile, electrolysers could help to keep H_2 network pressure within the required range. (Note that the volumetric enthalpy of H_2 is around 25% of that of methane, so swings in demand will have a larger effect on network pressure for H_2 than gas).

This configuration would require H_2 injection of into dedicated networks, rather than the existing gas network; it would also require significant electrolyser capacity to affect network pressure. Alternatively, where electrolysed H_2 is injected into the natural gas grid, total volumes will be too small to affect the grid pressure.

> Provision of ancillary services can provide value to electrolysers, and may make the difference between positive and negative returns for projects on weak grids where renewable curtailment is high and reinforcement costs are large. They do not however decide the case for large, transmission network connected electrolysers acting as a reservoir for renewable oversupply.

[68] The electricity costs and H_2 revenues for the time the electrolyser is providing the PSH service are ignored; we assume that the asset will be asked to provide support in both directions (low and high) during the year and therefore these costs will balance out.

3.4.5 Key findings

The key conclusion from the analysis above is that while the Base Case scenario (ESME Scenario 3) has high penetration of renewables (94GW in 2050 - leading to the curtailment of 23TWh of renewables and offering a good opportunity for accessing that zero-cost electricity) the multi vector solution of electrolysis is not competitive with transmission reinforcement. Investing in selective reinforcement of the most congested transmission lines in the country could provide greater net benefit to the system, and lower levels of curtailment. This can be attributed to the high capital costs of electrolysis, compared to the relatively low value of H_2 in the energy system (given by the ESME shadow price).

For electrolysis to become economically competitive at a transmission level in the 2050 scenarios modelled here, the value of H_2 must increase to levels around £50/MWh and/or its capex reduce by more than 25% below the base scenario value defined in ESME. In that case, electrolysis leads to similar or greater total system benefit and lower residual curtailment of renewables. Electrolysis could also provide a number of ancillary services to the electricity market thanks to its flexibility and quick response to control signals, increasing its system value in this way.

From a private ownership point of view (rather than a systems perspective, which is the focus of this analysis), regulatory drivers such as feed-in tariffs for renewable H_2 would increase the H_2 value and drive investment in this area, especially in regions with high levels of renewable oversupply.

The alternative multi vector case - methanation - seems to be significantly less economically attractive than electrolysis, due to its higher capital and operational fixed costs, and further efficiency loss. Methanation brings significant system benefit only if it leads to net carbon reduction in the system - removing CO_2 that would otherwise be emitted into the atmosphere., There is however limited potential for such a scenario in a future low-carbon electricity system. In all other cases, the economic viability of methanation as a system-level solution to renewables spill requires significant reduction of cost and/or efficiency improvement.

3.4.6 Operational and Engineering Implications

Challenges associated with the transition to multi vector operation have been collated through consultation with industry stakeholders and other experts, and are summarised in the table below. Further analysis is provided in the accompanying report *Barriers to Multi Vector Energy Supply.*

	Issue	Impact and Solution / Mitigation
Technical / Regulatory	**H2 concentration limits for gas networks** Hydrogen blending – the injection of hydrogen into the gas grid – is constrained by the maximum H_2 concentration limit specified in GSMR. If electrolysis is done at a large-scale using the energy surplus from large renewables plants such as wind farms, the gas supply volume at injection points will define the maximum allowed volume of H_2. See below under and Appendix 5.1 for further analysis of this issue.	Trials investigating the upper blend limit in Germany have injected hydrogen at up to 10% per volume. In the UK, the recently awarded HyDeploy project, will assess the upper limits on hydrogen blending based on trials at the University of Keele, Constraints on hydrogen levels can arise from: • Risks associated with bacterial growth in underground gas storage facilities leading to the formation of H_2S (an associated limit on the maximum acceptable hydrogen concentration in natural gas has not yet been determined). • Steel tanks in natural gas vehicles: specification UN ECE R 110 stipulates a limit value for hydrogen of 2% by volume, though the industry is moving to Type 4 carbon fibre tanks which can accommodate hydrogen at any concentration. • Gas turbines; most of the currently installed gas turbines were specified for a H_2 fraction in natural gas of 1% by volume or lower – 5% may be attainable with minor modification or tuning measures, some new or upgraded types will be able to cope with concentrations up to 15% by volume. • Gas engines: it is recommended to restrict the hydrogen concentration to 2% by volume. Higher concentrations may be possible for dedicated gas engines with sophisticated control systems if the methane number of the natural gas/hydrogen mixture is well above the specified minimum value. Clarke Energy have quoted a current limit of 4% hydrogen, with R&D it may be possible to increase this limit. • Many process gas chromatographs will not be capable of analysing hydrogen. Emerson have recently obtained approval for a new gas chromatograph that can meet Ofgem accuracy requirements, including those for hydrogen. It seems likely that these constraints could be reduced with the appropriate R&D effort, and that 10% is a reasonable limit to assume for the longer term. Distributed hydrogen storage could also alleviate the problem by enabling hydrogen to be stored at points of high RES capacity and injected when sufficient natural gas flows through the pipelines. Alternatively, when blending is constrained, the H_2 produced via electrolysis could be supplied to other markets such as the refining/steel industry and the transport sector as fuel for FCEVs.

Commercial	**Connection agreements with electricity and gas system operators**	The current policies for "firm" connection agreements of renewables with electricity network operators should be reviewed and adapted to the needs of renewables sites combined with P2G technologies. Gas network operators should also take a view of the commercial agreements offered to plants injecting H_2/SNG into the gas grid in the future.
Technical/ Commercial	**Supply chain and transportation of produced hydrogen and SNG** P2G solutions could work either by: a. using H_2/SNG produced centrally from large-scale electrolysers or methanators located close to large-scale renewables (such as large wind farms) and then injected into the grid via dedicated pipelines b. using smaller-scale electrolysers or methanators close to smaller renewables sites and a network pipelines to transport H_2 or CH_4 to the point(s) of injection into the gas grid, c. using electricity cables/lines to transmit electricity surplus from decentralised renewables to a central electrolysis or methanation unit close to a gas pipeline for direct injection	A cost-benefit analysis is required, considering: a. the location of renewables sites, their level of expected curtailment and their proximity to gas pipelines b. the economies of scale of electrolysers and methanators c. the cost of building new H_2/gas pipelines d. the cost of installing electricity cables/lines. Under the base case (ESME scenario 3), up to 5.3 mcm/d of hydrogen would be produced via electrolysis. To accommodate this amount of hydrogen in total on the gas transmission system (with a 10% limit on hydrogen concentration) nearly 50 mcm/d of natural gas would be needed to create the blend. With summer demand levels assumed to be around 100 mcm/d, this could not be achieved at a single location. However, it seems likely that this quantity of hydrogen could be accommodated if produced between 3 or 4 electrolysers sited at strategic locations on the NTS (clearly this would become more challenging if the limit on hydrogen within the mix was tighter than the 10% assumed above). If the Leeds H21 project H_2 sales price is assumed, the quantity of hydrogen produced could reach 15 mcm/d. With a summer demand level of around 100 mcm/d, and a 10% limit on hydrogen in the mix, this level of hydrogen could not be accommodated on the NTS in summer, regardless of electrolyser location. In such a case, alternatives such as hydrogen storage, methanation or use of hydrogen in other markets would be required (a 20% concentration level would help, although uncertainties around future gas supply profiles mean that it is not possible to be sure that constraints would not occur). In the scenario where secondary H_2 and synthetic gas markets are considered, products can be delivered by other means such as liquid truck or gaseous truck.

Regulatory	**Management and coordinated planning of electricity and gas networks**	Gas and electricity network operators should communicate regarding network constraints (interaction between the two parties will also optimise traditional network planning and expansion).
Technical	**Requirement for monitoring and control equipment to allow the switch between electricity generation and gas injection/storage at the appropriate time** Failure to switch to electrolysis of generation at the time when the electricity network is constrained would pose a risk to network assets. In the opposite scenario, in which gas flow is not sufficient at the injection point, failure to switch to H_2 storage could put the gas grid in risk. **Notification of intention to inject hydrogen into the gas network and consequences of unpredictability of electrolyser use**	Specialised monitoring and control equipment is needed for downstream measurement of H_2 content at the injection point and automatic reduction or switch to hydrogen storage if blending limit is exceeded. ANM systems for electricity networks could interact with the H_2 injection equipment, alerting the asset owner for the real-time operation of the grid. The requirement of an electrolyser to start and stop during the day is analogous to the variability of gas demand exhibited by a gas-fired power station. Any limitations on this variability (e.g. ramp rates) would be discussed between the electrolyser operator and the transmission system operator, and set out in the Network Entry Agreement or Local Operating Procedures. Injection of hydrogen into the gas network should be flagged to the gas transmission system operator in accordance with the requirements of the Uniform Network Code. At present, this involves the shipper “nominating” the quantity of gas they plan to bring onto the system on a day-ahead basis, with periodic opportunities to modify the nomination during the gas day. The operator of the delivery facility also notifies the system operator of its intended gas flow via “delivery flow notifications”. Differences between nominated and actual gas flows may attract scheduling charges. To the extent that electrolyser usage is unpredictable in short timescales, the relevant shippers are likely to need other flexible gas sources that can be used for balancing.

3.5 Case 5: Grid Power to Hydrogen for a Hydrogen Network

3.5.1 Introduction

Case study 4 considered the potential for electrolysis to convert excess renewable (wind, hydro and tidal) electricity across the UK into H_2 that can be blended into the natural gas grid, as an alternative to renewable energy curtailment or transmission reinforcement. However, H_2 has been considered not only as a means of oversupply mitigation, but also as the primary supply vector for heating and cooking energy demand, replacing natural gas.

This option is being investigated; most obviously at the H21 Leeds City gate project, a major innovation project that has assessed in detail the implication of re-purposing the distribution network in the city of Leeds and some of its suburbs to carry 100% H_2, fully replacing natural gas[69]. Although there are several different technologies for H_2 generation, the two most established technologies are steam methane reforming (SMR) of natural gas - converting methane to H_2 - and electrolysis, using electricity to split water into H_2 (and O_2). SMR, which can provide substantial quantities of largely carbon-free H_2 if combined with CCS, has been chosen as the H_2 generation technology in the H21 study.

This Case Study reviews the potential of a multi energy vector system – where the H_2 required for a city the size of Leeds can be produced via both those established generation technologies, and investigates whether such a multi vector configuration could:

- reduce investment and operational costs, and
- improve security of supply for the H_2 grid.

3.5.2 Overview of methodology and analytical tools

System Boundary

The setting for this Case Study is a city like Leeds, where the gas distribution network has been re-purposed to 100% H_2 supply; the Case Study boundary includes:

- the city's H_2 production and storage facilities,
- The H_2 network - supplying energy to domestic, industrial and commercial customers, to meet their hourly demand for heating, cooking and industrial processes.

The broader UK energy system, i.e., the national electricity generation capacity mix and demand for all energy vectors including electricity, H_2, gas and heating, is considered exogenous to the analysis; decisions made within the system boundary are assumed not to affect the national level operation of those vectors.

Single Vector Configuration

In the single vector configuration, hourly H_2 demand (for the whole year) is met using SMR with CCS combined with H_2 storage in salt caverns:

- The SMR-produced H_2 is transferred via a new transmission pipeline from the centre of production to the distribution network.
- Salt cavern storage is used to help manage both the significant inter-seasonal swings observed between winter and summer (due primarily to domestic heating), and the intra-day swings in demand, especially given the low ramping rates for the primary H_2 production process (SMR).

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[69] http://www.northerngasnetworks.co.uk/document/H21-leeds-city-gate/

The system is required to meet the 1-in-20 peak winter demand; SMR and storage are sized accordingly. For this analysis, a single type of H_2 storage has been modelled to meet both inter-seasonal and intra-day swings, but in practice a range of facilities types could exist.

Multi Vector Configuration

In the multi vector configuration, H_2 supply is provided by the combined operation of SMR with CCS and electrolysis powered by grid electricity, with the latter able to provide better intra-day response for matching rapid hourly swings in demand thanks to its faster ramping rates. Salt cavern H_2 storage is available, to be charged by both H_2 production technologies and discharged to match intra-day and inter-seasonal changes in demand. The peak 1-in-20 winter demand can be supplied by the combination of these technologies.

The purpose of this Case Study is to examine the potential benefit of this multi vector configuration - comprising savings in total investment and operational cost - over the single vector approach.

Cost Minimisation and Hydrogen Generation Dispatch Optimisation Tool

The benefit of a multi vector over single vector solution has been determined by comparing the total investment and operational costs in the two cases; an optimisation tool has been developed. As illustrated in the following diagram, the tool uses the following inputs:

- the hourly H_2 demand profile[70]
- natural gas price
- hourly electricity price profile
- cost data (capex, variable and fixed opex) for the examined technologies
- technical characteristic data for each technology

The model solves a linear optimisation problem which minimises the total cost subject to energy balance and technical constraints - the outputs for each configuration are:

- the optimal sizing of H_2 production and storage technologies, including:
  - SMR capacity
  - electrolysis capacity (in the multi vector case)
  - storage power rating (deliverability), assuming the same maximum rate for charging and discharging
  - storage volume (capacity)
- the hourly dispatch for the production technologies and storage
- the total investment and operational cost per year.

[70] The H2 demand profile reflects the required flow of H2 at the meter point, implicitly accounting for any heat storage within buildings.

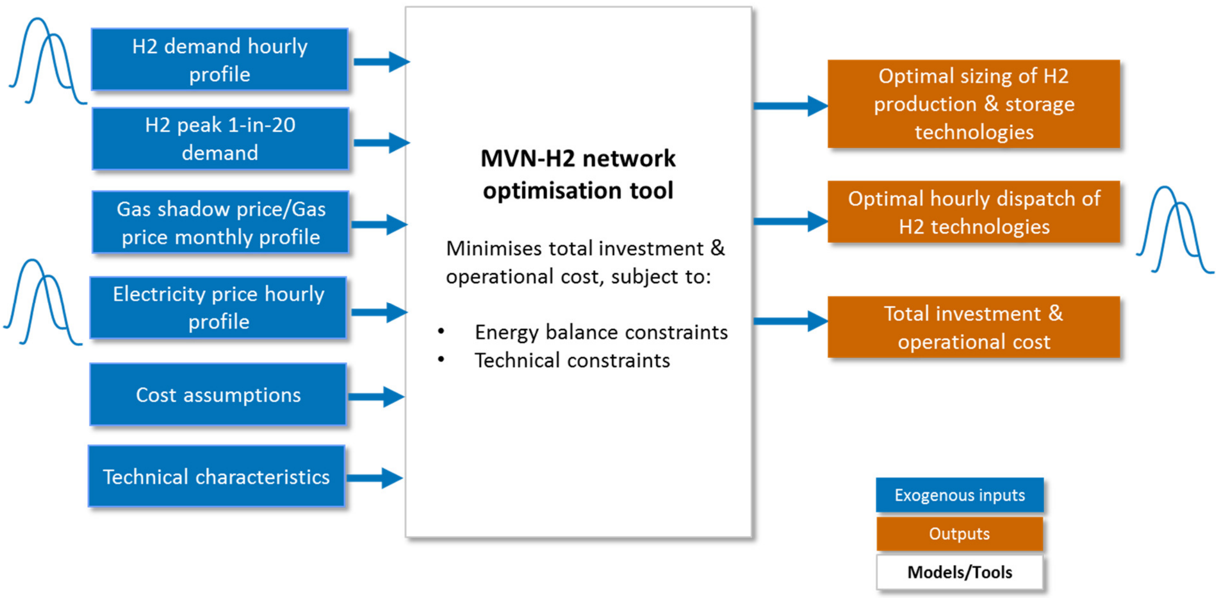

Figure 50- Description of H_2 network optimisation tool

3.5.3 Scenario Definition and Assumptions

Hydrogen Demand - Hourly Profile

To generate the hourly H_2 demand profile which the supply system must meet, the heat demand profile from the Carbon Trust micro-CHP field trials[71] has been used (for both domestic and non-domestic customers). These profiles are derived by averaging all weekdays and all weekend days within each month across the (roughly 20) houses included in the Carbon Trust dataset. As such, they inherit some diversification, though an additional degree of diversification is added to smooth the profile appropriately to city level demand, where many more customers are connected[72]. The H_2 demand profile used in the model for the whole year is shown on an hourly basis in Figure 51. Figure 52 shows the hourly demand for a day in January, in which the two peaks, one when people wake up in the morning and one after work, can be seen clearly.

- As these two figures show, while the daily profile shape is similar across the year, the absolute values, and the maxima and minima, vary by month, with winter months having significantly more demand for H_2 due to higher heating needs.
- The annual H_2 demand is 6.4TWh; this figure is given in the Leeds H21 project report as the worst-case yearly gas consumption of the Leeds conversion area - derived by adjusting measure 2013 demand to the coldest average temperatures observed in the area in the last 30 years.
- The split between domestic and non-domestic demand is 63% and 37% respectively; using the hourly profile from the Carbon Trust micro-CHP trials and the assumed diversification factors, the maximum hourly demand seen by the network is 2,015MW.

The yearly profile is an input to the optimisation model, which ensures sufficient H_2 supply capacity and storage are built to satisfy this level of hourly demand. As well as meeting these average hourly demand levels, the total capacity of the H_2 generation and storage system must also be able to supply the

[71] Described in appendix 8.1

[72] The diversification factors scale the peak values by 25% and 10% for commercial and non-commercial demands respectively.

network in the event of 1-in-20 peak demand, taken as 3,180MW from the Leeds H21 project report. An additional constraint has been included in the model to ensure that this condition is met.

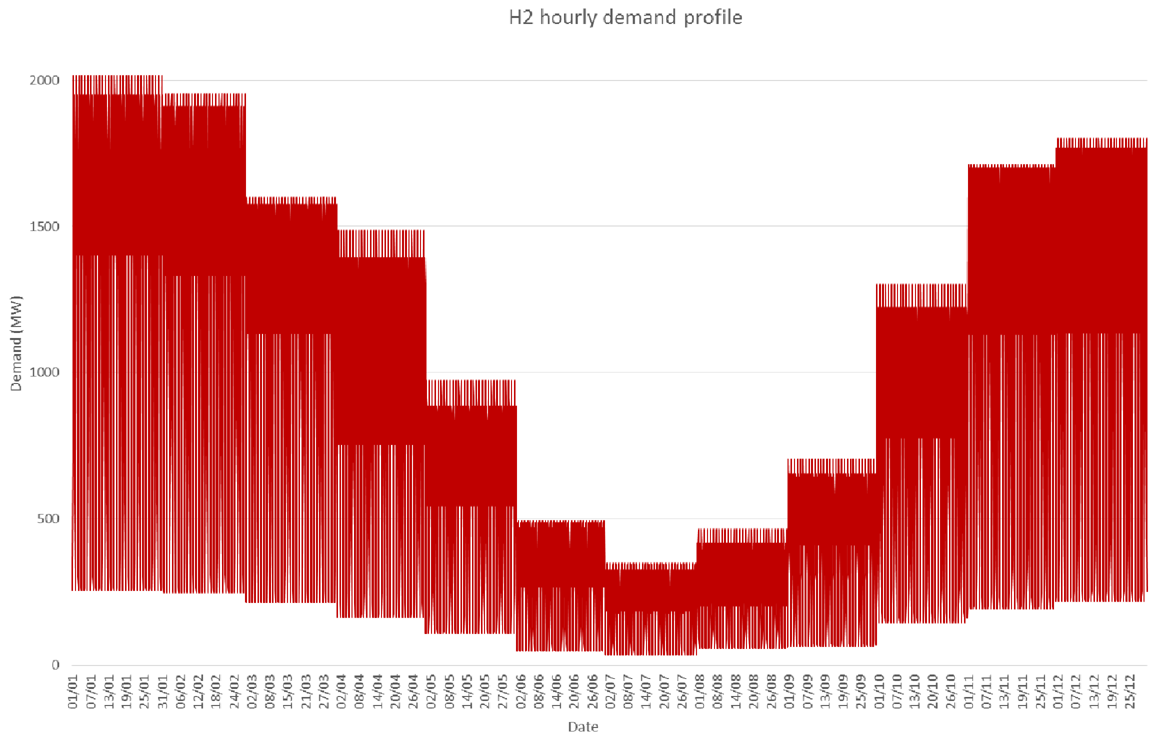

Figure 51-H_2 hourly demand profile for the Whole Year

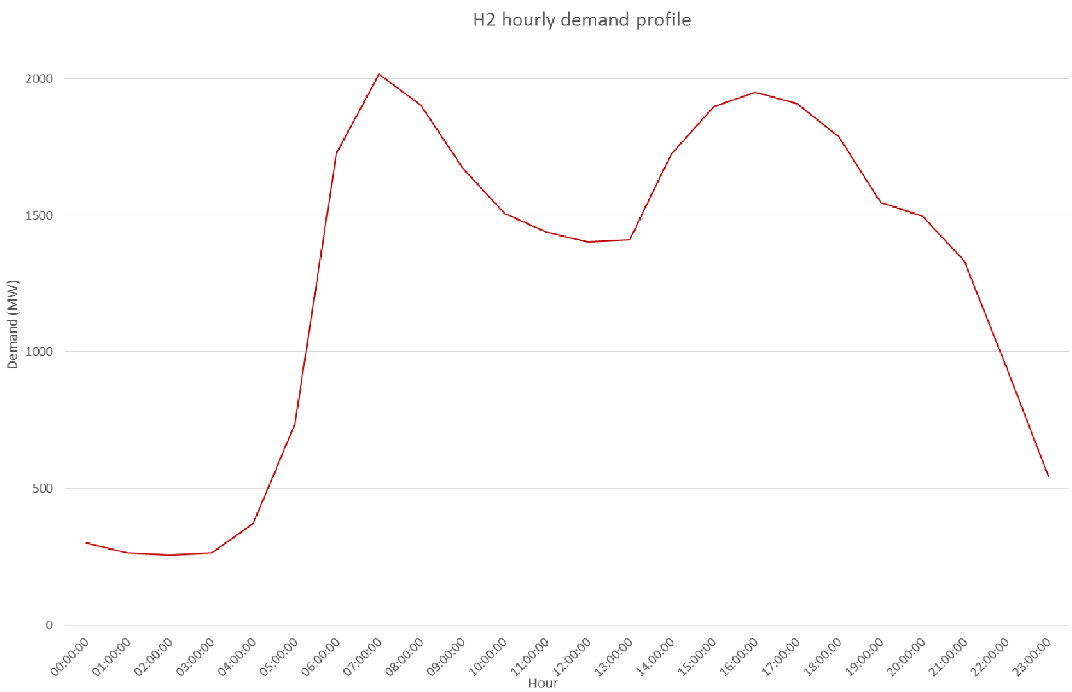

Figure 52-H_2 hourly demand profile for a January day

Natural gas and electricity price profiles

Natural gas and electricity price profiles are key model inputs, since they determine (along with other variable costs) the short-run marginal cost of producing H_2 using SMR and electrolysis and thus the optimal sizing of these technologies.

The 2050 ESME Scenario 3, presented in Case Study 4, has been used as the Base Case scenario, with the associated UK generation mix and time-sliced demand determined by ETI's ESME pathway optimisation model. Hourly wholesale electricity prices for this scenario have been obtained using the ESME2PLEXOS tool, developed to link ESME to PLEXOS - an electricity market modelling tool which determines the optimal hourly electricity dispatch to minimise total generation costs. The shadow price of natural gas corresponding to the base ESME scenario has been used as a proxy for the unit cost of wholesale natural gas.

The hourly electricity price profile vs the gas shadow price for the Base Case in 2050 are shown in Figure 53; the average electricity price is £47/MWh, while natural gas is costed at its ESME shadow price of £28/MWh.

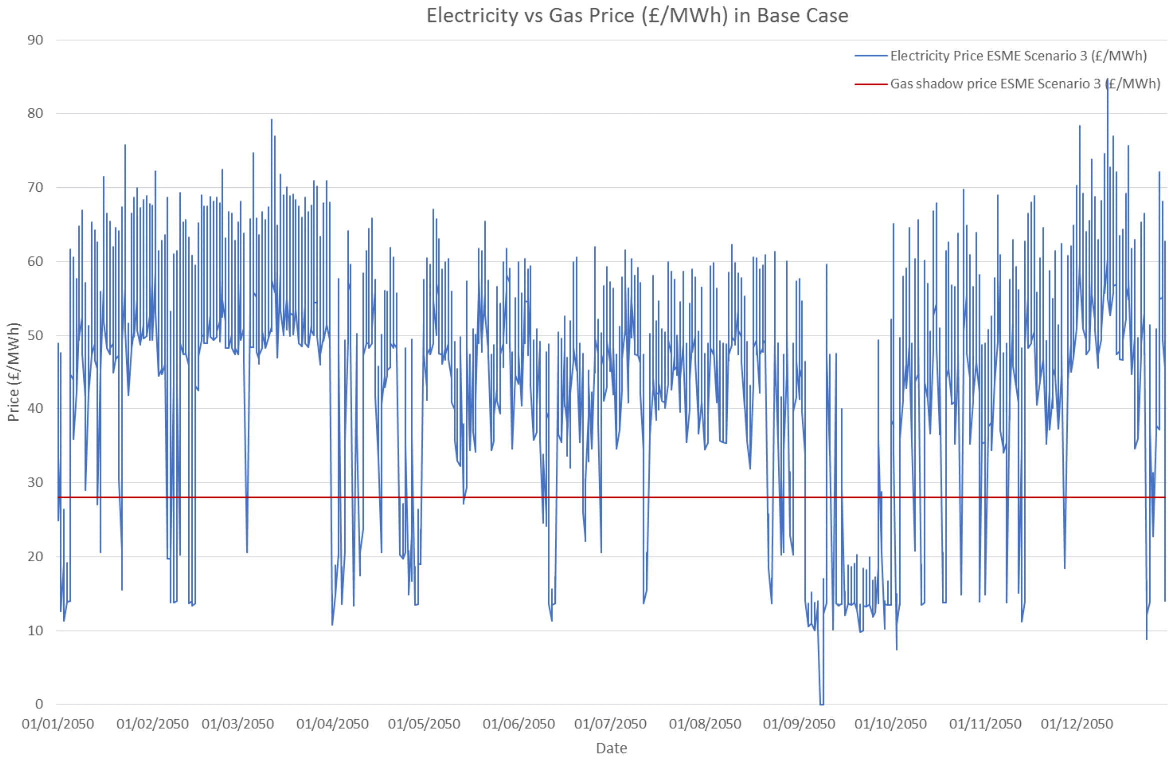

Figure 53-Electricity and Gas Prices Used in Base Case Scenario

Cost Assumptions and Technical Characteristics

The cost assumptions and technical data used in the modelling of the Base Case scenario are given in the following table. These include conversion efficiency data for each technology (SMR: gas to H_2, Electrolysis: electricity to H_2) as well as some technical constraints and economic data. The majority of the data are based on ESME v4.1 database, apart from the following:

- The electrolysis efficiency has been increased to 81% to be equal to that of SMR in 2050 (given in ESME v4.1), as there is evidence that these two technologies have already similar efficiencies[73]. This aligns with the efficiency figure used in Case Study 4 where electrolysis was also examined.
- The maximum ramp rate for SMR is based on information found in the Leeds H21 project report, while electrolysers are assumed to be able to fully ramp up/down within an hour based on publicly available data by NREL[74].
- Regarding H_2 storage, a sensible number for the minimum time for full charge/discharge (storage volume to power ratio constraint) has been derived based on the characteristics of the intra-day storage designed for the Leeds H21 project.
- Finally, to derive a figure for the cost of the transmission line as a function of the SMR capacity (in £/kW), we have assumed that the length of the H_2 transmission line built in this case study is the same as the total length of the H_2 transmission system envisaged in the Leeds H21 project, which is 190km in total.

Table 61-Economic and technical input assumptions in Base Case

	SMR	Electrolyser	H_2 salt cavern storage	H_2 transmission line to SMR
Efficiency (%)	81	81*	95	-
capex (£/kW)	459	701	0.01	-
capex for volume (£/kWh)	-	-	9.5	-
capex (£/kW/km)	-	-	-	0.25
Variable Operational & Maintenance costs (£/kWh)	0.001	0.001	0.001	-
H_2 Transmission Pipe Length (km)	-	-	-	190
Fixed Costs (£/kW/year, £/kWh/year for storage)	25	34	0.6	0
Economic lifetime (years)	30	20	20	50
Discount rate (%)	8			
Maximum ramp up/down rate (% of capacity)	5	100	-	-
Minimum time for full charge/discharge (h)	-	-	6	-

[73] http://www.northerngasnetworks.co.uk/document/H21-leeds-city-gate/

[74] *Novel Electrolyser Applications: Providing more than just Hydrogen* (NREL)

3.5.4 Case Study Analysis

Base case scenario

In the Base case scenario, the results for the single and multi vector configurations are presented in the table below. The H_2 demand is met by SMR and H_2 storage both in single and multi vector scenarios, i.e., the model has determined that building electrolysis does not provide a system benefit.

Table 62-Base Case results

	Base Scenario	
	Single Vector	Multi Vector
Electricity Prices	ESME2PLEXOS Scenario 3 (£47/MWh average)	
Gas Prices	As per ESME Scenario 3 (£28/MWh average)	
SMR capacity (MW)	1,288	1,288
Electrolyser capacity (MW)	-	-
H_2 storage volume (MWh)	11,354	11,354
H_2 Storage discharge/charge rate (MW)	1,892	1,892
Total investment and operational savings (£m)	-	-

To determine the conditions under which the multi vector configuration would provide some overall cost benefit to the system, a number of sensitivities have been investigated.

Sensitivities

Electrolyser Capital Cost

The following table shows two examples of electrolysis cost reduction that have been examined. The results show that capex alone does not have a material impact on the solution; even an extreme 70% reduction (from the ETI's projection in 2050, used in ESME v4.1) would lead to low levels of electrolysis being built, at almost zero cost saving.

Table 63-Sensitivity of Results to Electrolyser Capex

	Sensitivity 1 Electrolyser Capex			
	Single Vector	Multi Vector	Single Vector	Multi Vector
capex Reduction	50%		70%	
SMR capacity (MW)	1,288	1,288	1,288	1,259
Electrolyser capacity (MW)	-	-	-	28
H_2 storage volume (MWh)	11,354	11,354	11,354	11,354
H_2 Storage discharge/charge rate (MW)	1,891	1,891	1,891	1,891
Total investment and operational (£m)	370	370	370	370
Total investment and operational cost savings compared to single vector	-	-	-	0.08%

Sensitivity to Electricity Prices

The next sensitivity considered is to the electricity prices - effectively the fuel price that electrolysers pay. As explained above, the electricity price profile used in the Base case is derived using PLEXOS, based on the ESME scenario 3, leading to an average value of £47/MWh in 2050. The sensitivity of the solution to a number of different price scenarios has been tested; in each, the shape of the original profile has been kept fixed, while the hourly price has been reduced by shifting the curve down - subtracting a constant. The results for the different price time-series are below, and indicate that the multi vector solution could provide benefit if electricity prices were significantly lower than the projections for 2050 in the Base Case:

- The more the average electricity price is reduced, the larger the capacity of electrolysis is built in the system and the higher the cost saving that the multi vector configuration can offer.
- When electrolysis is built in the system, the need for SMR capacity is reduced and the volume and rating (deliverability) of H_2 storage are reduced.

Therefore, electrolysis not only competes with SMR in matching the baseload demand but also with storage; as it is more flexible than SMR - with faster ramping rates - it can provide support in matching intra-day swings which would otherwise be provided by intra-day storage. To put this in context, when electricity prices in 2050 drop by £20/MWh - to an average of £27/MWh - the saving is around £6m which corresponds to a reduction of approximately 1.6% total annual cost.

Table 64- Sensitivity of Results to Electricity Prices

	Sensitivity 2- Electricity Price					
	Single Vector	Multi Vector	Single Vector	Multi Vector	Single Vector	Multi Vector
Average price shifted by (£/MWh)	-10		-15		-20	
Final average electricity price (£/MWh)	37		32		27	
SMR capacity (MW)	1,288	1,258	1,288	1,252	1,288	898
Electrolyser capacity (MW)	-	-	-	38	-	419
H_2 storage volume (MWh)	11,354	11,349	11,354	11,354	11,354	11,354
H_2 Storage discharge/charge rate (MW)	1,892	1,892	1,892	1,892	1,892	1,892
Total investment and operational cost (£m)	365	365	363	363	361	355
Total investment and operational cost savings compared to single vector	-	-	-	0.03%	-	1.6%

Storage Minimum Discharge Time (Power to Volume Constraint)

Since electrolysers can compete with storage, we now investigate how the minimum storage discharge time, i.e., the volume to power (deliverability) ratio assumed for the H_2 storage affects the results; a lower minimum discharge time for the storage element in the model means it behaves like an intra-day storage, while a higher discharge time means its behaviour is closer to that of an inter-seasonal storage.

As above, the Base Case discharge time is assumed to be 6 hours; approximately the volume-to-charging power ratio of the intraday storage designed for the Leeds H21 project. For the inter-seasonal storage, the corresponding figure is over 435 hours; we note the minimum discharge time for both inter-seasonal and intraday storage is greater than the charging time.

The effect of varying the minimum discharge time are shown in the table below;

- by increasing the discharge time, i.e., the volume to power ratio constraint, in the single vector scenario, the H_2 storage total volume is also increased as the discharge/charge rate required to meet the peak 1-in-20 demand remains the same.
- The higher the storage discharge time, the greater the economic benefit that the multi vector solution provides - larger levels of electrolysis are built to replace diurnal storage which would come at a greater cost due to the imposed volume to power ratio constraint.
- For the highest discharge time examined in this study – 168 hours - there is a reduction of around 7% in total operational and investment cost per year. This suggests that where access to the appropriate geology for H_2 storage is limited - with resulting higher costs or lower deliverability - there may be scope for electrolysers to provide some of the required flexibility.

Table 65-Sensitivity of Results to Minimum Storage Discharge Time

	Sensitivity 3 - Minimum Discharge Time					
	Single Vector	Multi Vector	Single Vector	Multi Vector	Single Vector	Multi Vector
Minimum storage discharge time (h)	72		96		168	
SMR capacity (MW)	2,551	2,410	2,551	2,285	2,551	2,113
Electrolyser capacity (MW)	-	260	-	491	-	805
H_2 storage volume (MWh)	45,301	36,700	60,402	38,757	105,704	43,975
H_2 Storage discharge/charge rate (MW)	629	510	629	403	629	262
Total investment and operational cost (£m)	517	515	542	533	620	575
Total investment and operational cost savings compared to SV	-	0.3%	-	2%	-	7%

Electrolysers cannot, in general, compete with SMRs on price for hydrogen generation at scale; even at low capital costs and electricity prices, and with constraints on storage provision, it remains a marginal contributor at most to hydrogen for heat networks. This agrees with the assessment of the H21 report.

3.5.5 Key Findings

Given the results for the Base Case as well as the different sensitivities examined in the optimisation model, overall the cost of electrolysis suggests that electricity prices would need to be low relative to gas prices for it to play a role. The greater flexibility of electrolysers relative to SMR is a benefit, but this may only become material if cost or availability of storage is constrained. Otherwise, diurnal storage could match the intra-day swings in a more cost-effective manner while SMR could provide the base load using a lower cost fuel (gas). In favourable cases, a material amount of capacity could become economic, although the impact on net costs is modest.

3.5.6 Operational and engineering implications

Here we focus only on the issues associated with the multi vector system including power-to-gas. The Leeds H21 project has provided a very detailed analysis of the issues associated with conversion of gas grids to operate on hydrogen, including capacity, operation, appliance conversion, finance and regulation; we do not attempt to replicate that analysis here.

	Issue	Impact and Solution / Mitigation
Commercial	**Commercial framework for co-existence of SMR and electrolysis sources**	**Commercial model:** This Case Study considers the co-existence of SMR and electrolysers feeding hydrogen into the gas grid. A commercial framework will be required for the production and transportation of hydrogen from multiple sources. It is possible to envisage several different models, for example: • An integrated and highly regulated approach, in which the network operator seeks to optimise the system through operation of the transportation infrastructure and purchases of the commodity and of storage services • A liberalised approach, more akin to that in place for natural gas, with full separation between transportation and supply, and retail competition • A middle-ground of some sort, e.g. with separation of transportation and supply but a monopoly supply franchise While any of these approaches could be made to work, the greater the level of liberalisation, the more complex the framework would become. We note that the Leeds H21 model the matches supply of hydrogen to demand across the day; suggesting that the commercial framework would have to operate on an hourly basis rather than the daily basis that is used in the liberalised gas market[75]. An alternative would be for the hydrogen distribution network operator to take responsibility for the intra-day storage site, with hydrogen suppliers required to produce a flat product. However, since electrolysis could potentially have a joint role as a hydrogen supply source and a substitute for transportation capacity and/or diurnal storage, a further level of complexity would have to be built into the framework if electrolysis were to be accommodated. **Connection agreements:** The injection of hydrogen produced by electrolysis into the MP system would necessitate the offset of an equivalent amount of production from the upstream system (assuming no line pack or network storage at the lower pressure tiers of the network, as is the case today). In a command and control situation run by a

[75] In the gas market, the distribution network operator has the responsibility to provide diurnal storage, with gas provided (commercially) by shippers on a flat basis.

		single entity, this is not a problem, but could be more of an issue in a more liberalised hydrogen supply market, and might require prioritisation of producers (in practice there is likely to be some linepack available in the higher pressure hydrogen transmission pipelines which could help to manage supply variations). There are likely to be some operational constraints which the network operator would have to manage, such as the rate at which SMRs can increase and decrease levels of production (+/- 5% of design capacity per hour); the availability of storage and (potentially) HTS linepack would help with this.
Commercial	**Low cost electricity is required for electrolysis to be economic as part of MV solution.**	The role for electrolysis in the system is more favourable in areas where low price electricity is available. Renewable generation that would otherwise be curtailed is one source, although as shown in the earlier part of Case Study 4, there are issues with sizing the electrolyser to achieve an economic load factor. Another means of improving the economics of electrolysis would be to use the electrolyser to provide grid services. Both alkaline and particularly PEM electrolysers can rapidly change their output in response to control signals and, as such, are able to provide both reserve and response services. The potential size of the market for grid services on the timeframes consistent with transitioning of the gas grid to hydrogen (or, alternatively, the large-scale adoption of hydrogen fuelled vehicles) is uncertain. A better view of the size of the balancing services market in the future, allowing for the significant evolution expected in the power sector, would inform assessments of the likely role for electrolysers in the energy system.
Regulatory	**Policy uncertainty is a barrier to industry progress toward a transition to hydrogen supply**	There are significant policy and regulatory questions to be resolved regarding transition of gas networks to hydrogen supply. Not least, the uncertainty around heat policy and the pathway to decarbonisation of the heat sector makes it very difficult for network companies to plan investment and is a barrier to initiating the substantial amount of work that will need to be done in developing appropriate industry codes. These issues are covered in detail elsewhere, for example the Leeds H21 report and CCC report on Future Regulation of the UK Gas Grid[76].

[76] Future regulation of the UK gas grid, Frontier Economics and Aqua Consultants, CCC, June 2016

Technical	**Electrolyser are potentially significant loads and could face expensive network connection charges in demand constrained areas.**	Electrolysers can modulate output to stay within demand limit, as shown in the SSEN Aberdeen trials[77], in which electrolysers were shown to be able to respond rapidly to set-points to avoid breaching a demand constraint. The report notes that an appropriate charging mechanism will be needed to incentivise this behaviour, such as time of use, real-time pricing or payments for participation in a demand side response or active network management scheme.
Technical	**Electrolyser impact on power factor.**	The Aberdeen electrolyser study also demonstrated that the electrolysers can have a significant impact on network power factor (increased electrolyser load results in a reduction of the power factor). This could require significant power factor correction, though the Aberdeen report makes the point that reactive power is not necessarily a problem, and could indeed manage voltage issues, such as those caused by wind generators.
Technical	**A co-ordinated planning process will be required to integrate the use of electrolysers and SMRs within a hydrogen network.**	Broadly speaking, the presence of an electrolyser within a hydrogen distribution network is analogous to a biomethane plant injecting into the current gas grid. As identified above, the potential for an electrolyser to be a source of supply and a substitute for transportation capacity and diurnal storage adds a potential level of complexity, which would lend itself to a more integrated and regulated approach.
Technical	**A clear control process will be required to integrate the use of electrolysers and SMRs within a hydrogen network.**	The injection of hydrogen produced by electrolysis into the MP system would necessitate the reduction of production from the upstream system by an equivalent amount (assuming no line pack or network storage at the lower pressure tiers of the network, as is the case today). The control process would require real-time information on input flows together with an appropriate mechanism for the system operator to adjust flows from upstream sources.

[77] Impact of electrolysers on distribution networks, part of the Aberdeen Hydrogen Project, SSEN, November 2016

3.6 Case 6a: District Heating

3.6.1 Case Introduction

Decarbonisation of the UK electrical sector has driven the substantial increase in connections of small, distributed generation plants such as wind farms and solar PV to distribution grids; this has led to overloading of some network areas which cannot accommodate further distributed generation unless:

- significant network reinforcement is carried out, or
- curtailment of the plants' export is ensured at times of binding network constraint.

At the same time, one option for the decarbonisation of heat in built-up areas is district heating, supplied by large scale heat pumps which can offer high efficiencies and substantial reductions in carbon emissions (provided the source of electricity is also low carbon). In this Case Study, we consider bringing those two systems together in a multi vector arrangement, to:

- reduce wind energy curtailment due to network constraints
- decrease the need for conventional network reinforcement
- provide a local generation source for heat pump-based district heating systems.

The following map shows the potential locations where DH networks are likely to be built until 2050 based on an analysis carried out by Element Energy for CCC[78], which includes a geospatial analysis of heat demand density and points of potential supply. Existing wind farms and PV farms[79] in the UK are also shown on the map, these give an initial view of potential future opportunities for synergy between wind farms and DH systems. The dataset used includes 764 wind farms, 97% of which are embedded in the distribution system, with the rest connected to the transmission system; existing wind farms seem to be concentrated in North Scotland, Northern Ireland, Yorkshire, the North East and Cornwall, suggesting that these areas have good wind resources and will therefore attract interest for further investment in wind energy. Information on existing embedded PV systems is limited.

On the other end, the same map indicates that the areas which are best candidates for DH networks are the Greater London area (which is densely populated), the North East and North West of England as well as the Midlands and Yorkshire. Some areas favour DH networks but not wind farms (such as London), in others (such as the North East, Yorkshire as well as Cornwall and areas in Scotland) the two systems could cooperate, improving network conditions for further generation connections and providing access to low cost electricity for heating.

In addition to the spatial information on connected wind farms shown in Figure 54, Figure 55 shows a representative part of a distribution network in the South East of England, with many new connections and accepted (contracted) offers for new embedded wind and PV farms. According to UK Power Networks[80], the area has a number of constraints, some of which are thermal constraints related to power flow limits on lines and transformers. Western Power Distribution experiences similar issues in each network, with West and East Midlands being characteristic examples of networks suffering thermal overload on their lines and reverse power flow on their transformers[81].

Give current network conditions, and the further decentralisation of electricity generation expected in the future, and the ongoing decarbonisation of heat; embedded renewables supplying electricity for district heating may represent a part of the future network management solution.

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[78] Research on District Heating and Local Approaches to Heat Decarbonisation

[79] Existing UK wind and PV farms dataset available on http://www.variablepitch.co.uk

[80] Distributed Generation Customer Forum slides, September 2016

[81] WPD, West Midlands Distributed Generation Constraint Map

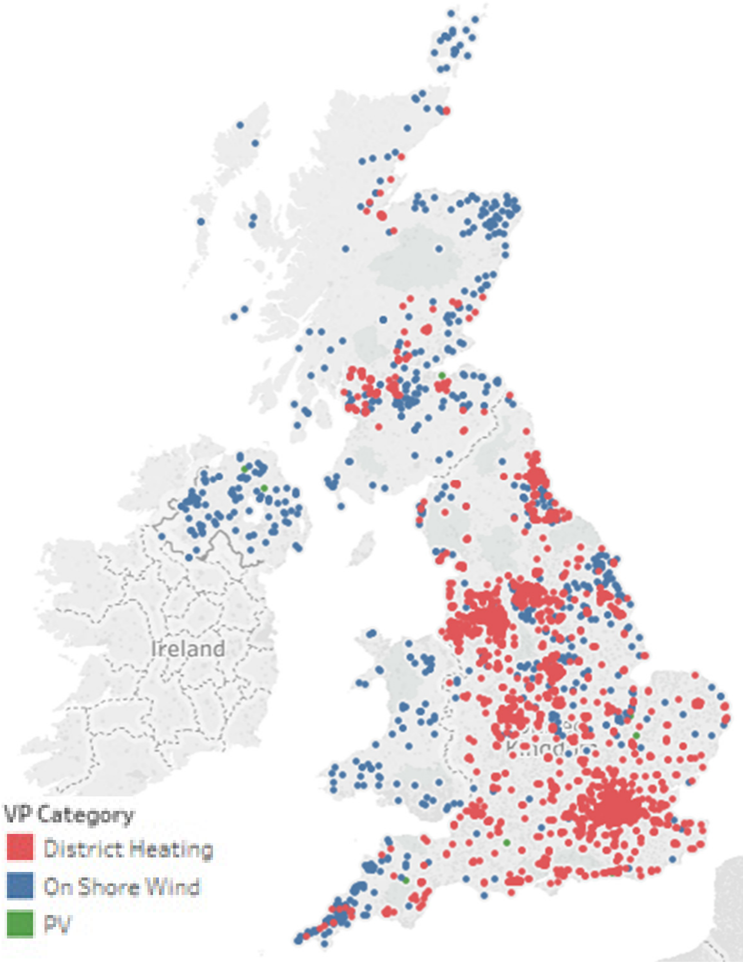

Figure 54-Future Potential DH Network Locations and Existing Wind and Solar Farms In The UK

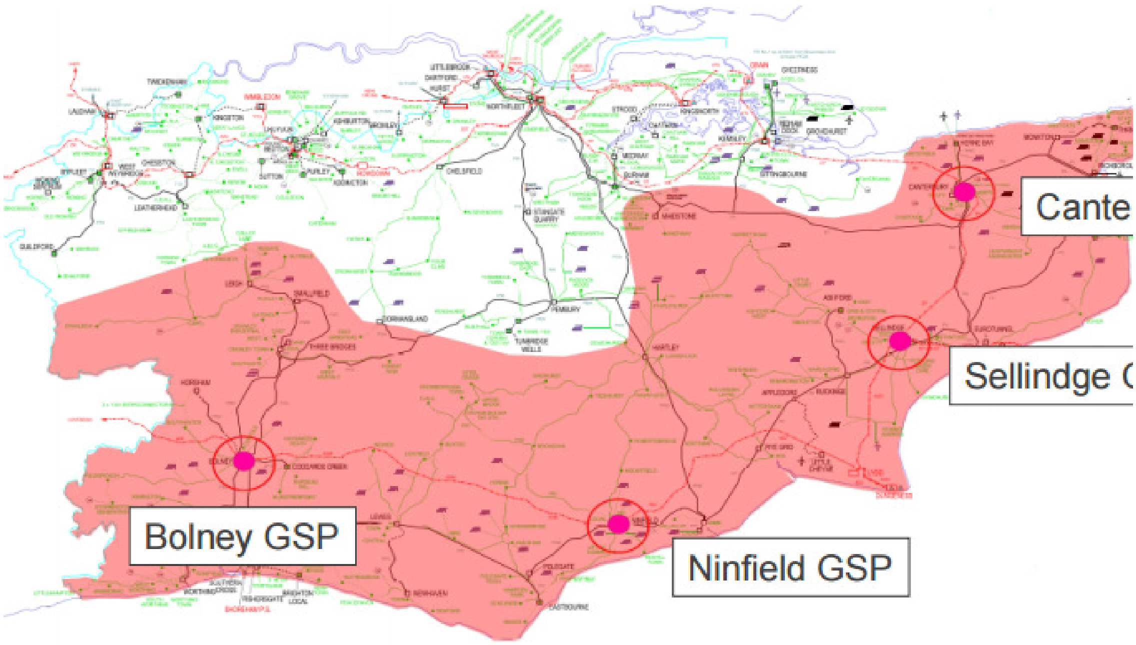

Figure 55-Constrained distribution network area in Southern Eastern Network (UK Power Networks)

3.6.2 Overview of methodology and analytical tools

System Boundary

The Case Study boundary is taken to include two separate systems:

- The first is a town in which domestic, and industrial and commercial heating demand is supplied via a heat pump-based district heating network, using electricity from the grid.
- In parallel, at a distance of a few kilometres, a wind farm is connected to a primary distribution substation which supplies the electricity demand of local town using the wind generation as a local supply renewable of energy.

The broader UK energy system - the national electricity generation capacity mix and demand for all energy vectors including electricity and heating - are considered external to the analysis; decisions taken inside the boundary are assumed not to affect the system and market operation of those energy vectors at a national level.

Single Vector Configurations

This Case Study considers two independent single vector configurations representing the district heating network and the wind farm.

Heat Network

The district heating network supplies 51GWh of heat, the equivalent of 1% Leeds' total heating demand, (which is considered in Case Study 5) generated by a central heat pump supported by a thermal storage system. As the key elements here are the heat pump and storage capacities, the topology of the network is not considered; the full system is represented by a single heat pump unit and a single storage unit. The heat pump draws power solely from the grid, converting it to an amount of heat given by its coefficient of performance (CoP). Storage allows the heat pump to produce heat during period of low electrical prices, to be used later during periods of higher prices.

The single vector system is optimised then based on:

- the electricity price signal
- the cost of heat pump and storage technologies per unit of capacity

As in the previous case, the heat network is also required to be capable of meeting the 1-in-20 peak demand through the combined use of the heat pump and the thermal storage.

Wind Farm Connected to Primary Distribution Substation

In parallel - without any direct connection to district heating system described above - a wind farm with a capacity between 7.5MW and 30MW is connected to a primary 33/11 kV distribution substation equipped with a single 5MW transformer in a rural area, and sells its export to a nearby town, also supplied by the same distribution substation.

When the wind farm generation cannot meet the town's electricity demand, the substation imports electricity from the grid; when wind generation exceeds the town's demand, the wind farm can sell the surplus to the grid, causing reverse power flow on the transformer's windings. Since the substation is equipped with only one primary transformer, the power that can be exported back to the grid, i.e., the level of reverse power flow, is limited by the transformer's rating.

Where the power flow on the transformer exceeds its rating, a decision must be taken on whether to:

- curtail the wind production and lose revenues, or
- invest in upgrading the transformer to allow for an increased export.

The wind farm capacity range is selected as the Case Study considers a scenario in which a wind farm connects to a constrained part of the network, therefore, the wind farm's rated output must exceed the transformer's rating (net of the minimum local demand level), while not being prohibitively large for it to connect to the distribution network (but instead connect to higher voltages or the transmission network).

We note that in reality, a wind farm might connect to a more complex part of the distribution network, for example an interconnected rather than radial network (as assumed here), as well as on a substation that has more than one transformers feeding it. In the latter case, network constraints can be violated under different network configurations (e.g. N-1 configuration) which create several different power flow scenarios. Further, in addition to bottlenecks due to the transformer ratings, thermal constraints could also arise due to limits on cable or OHL sections whose ratings are low, and which must be replaced for a new connection to be accepted by the network operator. The configuration assumed in this study is a simple case of a constrained network, but one that illustrates the potential benefits of a multi vector solution.

It should be also noted that the town energy demands are assumed to be outside the Case Study boundary, and therefore the cost to supply it with electricity (not generated at the wind farm) are not included in the model.

Multi Vector Configuration

In the multi vector configuration, the district heating system is as described in the single vector configuration above, except that can procure electricity not only from the grid, but also from the wind farm - by building a cable interconnecting the two systems. In turn, the wind farm can deal with excess generation, and avoid curtailment, either:

- by reinforcing the transformer to be able to sell it back to the grid, or
- by supplying it to the district heating system (with potential changes to the sizing of the heat pump or storage)

The goal of this Case Study is to understand:

a. whether there is a total system cost benefit in bringing the wind farm and the district heating system together, relative to the single vector optimised options of substation reinforcement and wind generation curtailment (before accounting for the cost of the interconnecting cable),

b. in the scenario where there is a net benefit, whether it justifies building the interconnecting cable, and what its maximum length would be, i.e., the maximum distance between the district heating network and the wind farm at which the interconnection remains economically viable,

c. whether connecting the heat network and wind farm has an impact on the sizing of the heating technologies (heat pump and thermal storage).

In other words, we aim to find the optimal trade-off between transformer reinforcement, potential over-sizing of heating technologies and the installation of an interconnecting cable.

Cost Minimisation and Heat Pump/Wind Farm Optimisation Tool

To understand whether the multi vector configuration confers an advantage over the individual single vector cases, the total costs of both options have been analysed using an optimisation tool. As illustrated in the diagram below, the tool uses the following data:

- the hourly heat demand profile of the heat network
- the hourly electrical demand profile of the town connected to the same substation as the wind farm
- the system-wide hourly electricity price profile

- cost data (e.g. Capex, variable costs, lifetime etc.) for the relevant technologies
- data on the technologies' technical characteristics
- the hourly wind farm load factor profile

The model solves a linear optimisation problem which minimises the total cost subject to energy balance and technical constraints. The outputs for each configuration are:

- Single vector - Heat Network
  - optimal sizing of the heat pump and thermal storage technologies
  - optimal hourly dispatch for the heat pump and thermal storage
  - total investment and operational cost per year
- Single vector - Wind Farm
  - hourly allowed generation/curtailment for the wind farm
  - optimal reinforcement of substation transformer (rating upgrade)
  - total revenues from selling electricity
  - annualised reinforcement costs

For the Multi vector scenario, the model solves for all the above, and:

  - optimal rating of the wind farm-heat pump interconnecting cable (maximum power flow on cable)

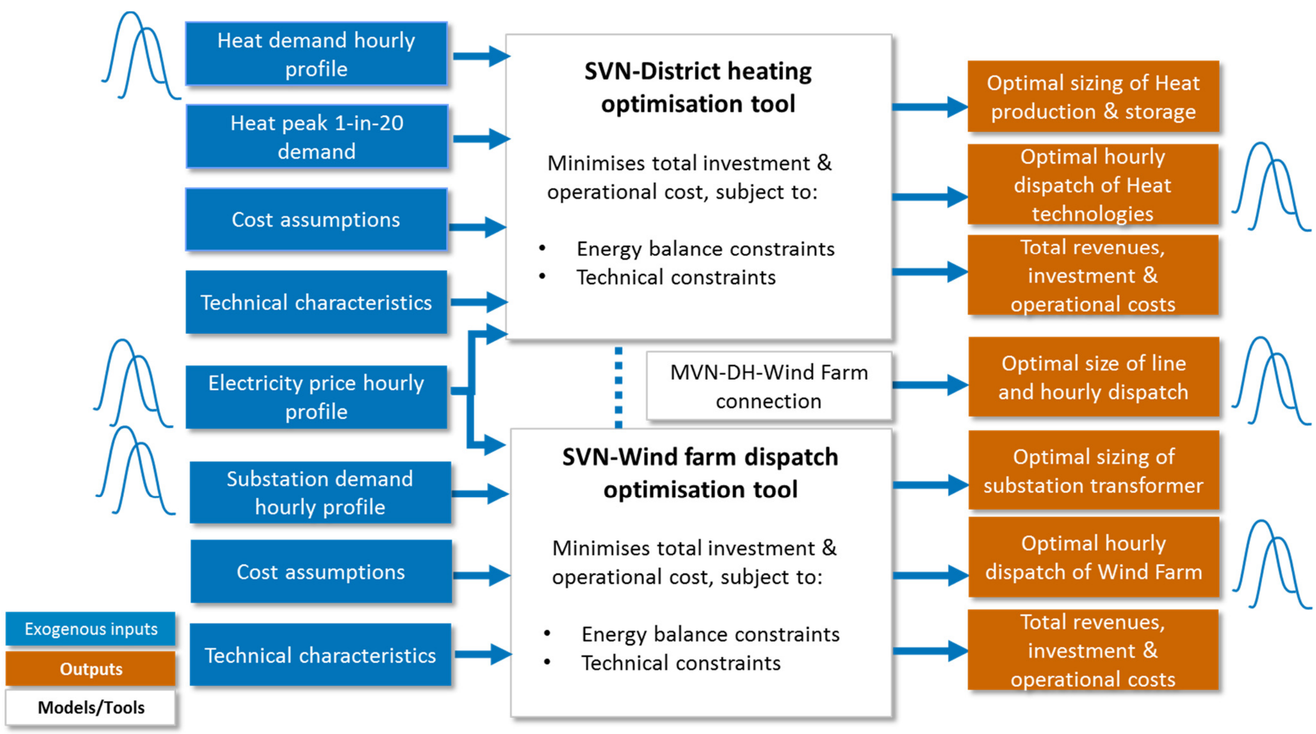

Figure 56- Description of The Optimisation Tool

3.6.3 Scenario Definition and Assumptions

Heat Demand - Hourly Profile

The hourly heat demand profile for the district heating system required in this Case Study is based on the heat profile used in Case Studies 2 and 5, derived from Carbon Trust micro-CHP field trials data; (the same diversification factors for domestic and non-domestic demand have been assumed, at 25% and 10% respectively, as in Case Study 5).

In terms of the absolute level of demand, it is envisaged that the size of the area supplied by the district heating system is 1% the size of Leeds, which was used as an example city in Case Study 5. Therefore, the level of demand was based on Leeds' total gas consumption, and the split between domestic and non-domestic demand is taken from the Leeds H21 project report. Subsequently, to estimate the thermal demand the district heating system has to meet, an assumed average conversion efficiency of gas boilers of 80% is applied (as per ESME V4.1 database). The resulting demand profile used in the model corresponds to a total yearly thermal demand of 51 GWh, while the maximum hourly heat demand seen by the DH network is 16 MW; corresponding to around 4,000 homes, at a diversified peak of 4kW/household for existing homes.

This profile is an input to the optimisation model, which ensures that the heat pump capacity and heat storage deliverability suffice to satisfy this level of demand. Further, while meeting average hourly demand levels, the combined capacity of the heat pump and storage system must be able to meet the 1-in-20 winter peak demand (as in Case Study 5), which is taken as 25MW, derived by scaling down the 1-in-20 gas peak demand in the Leeds H21 project appropriately for the assumed size of the district heating system and adjusting for efficiency as above.

Substation Electricity Demand Hourly Profile

The shape of the substation hourly electricity demand is based on an anonymised substation load profile provided by Element Energy; for the purposes of this modelling, this has been scaled accordingly to a maximum (1.7MW) and minimum level of demand (0.7MW) which are considered indicative values for the demand of a small, rural, UK town behind a primary substation equipped with a 5MW transformer.

Electricity Price Hourly Profile

The 2050 ESME Scenario 3, presented in Case Study 4, has been used as the Base Case scenario, with the associated UK generation mix and time-sliced demand determined by ETI's ESME pathway optimisation model. The same hourly wholesale electricity prices presented in Case Study 4 have been used, obtained using the ESME2PLEXOS tool developed for linking ESME to PLEXOS, an electricity market modelling tool which determines the optimal hourly electricity dispatch to minimise total generation costs.

The electricity prices seen by each component in the system vary as follows:

- Wind generation supplied to the local demand connected to the same distribution substation is sold at the wholesale electricity price, the system level price at which electricity is traded.
- Wind generation exported across the system boundary is sold at 96% of the wholesale electricity price, accounting for distribution network losses of 4% of the exported electricity, incurred from using the distribution network to deliver the energy to other, non-local demand.
- The price paid by the heat pump to import electricity from the grid is higher than the wholesale price by 5%, which accounts for 4% of distribution network losses and 1% of transmission losses[82].

[82] The figures for network losses were considered sensible values based on information published by DNOs on line loss factors (LLF) and Elexon on transmission loss multipliers (TLM) for demand respectively.

This 5% margin reflects the premium the heat pump must pay for using both the distribution and transmission networks to import electricity from non-embedded generators; as a result, using electricity directly from the wind farm leads to a reduction of the total system costs as these network costs are avoided.

Hourly Wind Load Factors

The wind load factor profile used for the wind farm's hourly available generation in this study is based on 2008 data for the Yorkshire and Humber region in the UK (see Appendix 7 for more information).

Cost Assumptions and Technical Characteristics

As a Base Case scenario, we assume a wind farm with an indicative capacity of 15 MW (within the scenario range of 7.5-30MW), connected to the substation through a 5 MW 33/11kV transformer.

In the single vector case, the wind farm generation that can be exported to the grid is limited by the transformer's reverse power flow constraint, which is assumed to be 75% of its rating. For the heat pump's coefficient of performance (CoP), a value of 4 has been fixed throughout the year, as ground-source heat pumps are less sensitive to seasonal temperature variation. For heat storage, the volume (MWh) to power (MW) deliverability ratio, i.e., the minimum time for full charge/discharge has been fixed at 1 hour.

The economic and technical assumptions used in the Base Case scenario are given in the following table; most are based on ESME v4.1 database, though storage costs are based on a study undertaken by Tyndall Centre[83], and the heat pump CoP is based on Element Energy's study on district heating[84]. The 33/11kV transformer cost per unit of rating - used as a proxy for the transformer's reinforcement cost – and the per km cable cost used in the multi vector scenario are based on EPN average values for network asset costs.

Table 66-Economic and technical input assumptions in Base Case

	Heat Pump (Ground source)	Thermal Storage	Primary Transformer (33/11kV)	11kV underground interconnecting cable
capex (£/MW)	936,000	10	258,655	
capex for volume (MWh)	-	41,000	-	
capex for cable (£/km)	-	-	-	730,000
Variable Operational & Maintenance costs (£/MWh)	1	1	-	-
Charging/discharging efficiency (%)	-	99	-	-
Coefficient of performance (CoP)	4	-	-	-
Minimum time for full charge/discharge (h)	-	1	-	-
Economic lifetime (years)	20	30	40	40
Discount rate (%)	8	8	8	8

[83] Potential for Thermal Storage to Reduce Overall Carbon Emissions from District Heating Systems

[84] BEIS - Heat Pumps in District Heating

3.6.4 Case Study Analysis

Base Case Scenario

The Base Case results for the single and multi vector configurations are presented in the table below.

Table 67-Base Case results

	Base Scenario	
	Single Vector	Multi Vector
Wind farm capacity (MW)	15	
Transformer rating (before reinforcement) (MW)	5	
Maximum hourly heating demand (MW)	16	
Electricity Prices	ESME2PLEXOS prices as per ESME Scenario 3 (£47/MWh average)	
Heat pump capacity (MW)	10	10
Heat storage volume (MWh)	51	51
Heat Storage discharge/charge rate (MW)	15	15
Total Wind Generation curtailed (MWh)	760	221
Transformer rating upgrade (MW)	0	0
Wind farm-Heat pump cable rating (MW)	-	3
Total multi vector system cost saving (£/% of single vector cost)	-	56,258 / 6%

In the single vector case, wind farm generation exceeds substation demand around 8% of the time leading to 760MWh of curtailed electricity, equivalent to 4% annual curtailment. The costs incurred by curtailing generation, however, are insufficient to justify the cost of upgrading the transformer.

This is alleviated by the possibility of exporting some of that generation to the district heating system; with total cost savings of around to 6% of the combined costs of both single vector systems. The system benefit comes mainly from the avoided transmission and distribution network costs that are incurred where heat pump electricity is imported from the transmission grid.

Cable Costs

The maximum power flow on the interconnecting cable was found to be around 2.5MW. Considering that cable investment costs do not vary linearly with capacity but depend primarily on labour costs and the cost for excavation and trenching (which are fixed regardless of the cable size), the total cost for building a 11kV underground cable of 5MW capacity is used as a proxy, at an annualised figure of £64,000/km. Under these assumptions, the observed savings could only justify building an interconnecting cable if the wind farm is less than 900m from the district heating system!

To determine conditions under which the multi vector configuration provides a greater benefit to the system, a number of sensitivities have been tested:

Sensitivities

Sensitivity to wind farm installed capacity

The following table shows the results for wind farm sizes at 50% and 200% of the Base Case scenario, i.e., 7.5MW and 30MW.

Table 68-Sensitivity to Wind farm capacity results

	Sensitivity 1- Wind Farm Capacity			
	Single Vector	Multi Vector	Single Vector	Multi Vector
Wind Farm capacity (MW)	7.5		30	
Heat pump capacity (MW)	51	51	51	51
Heat storage volume (MWh)	10	10	10	10
Heat Storage discharge/charge rate (MW)	15	15	15	15
Total Wind Generation Curtailed (MWh)	80	60	1,563	1,474
Transformer rating upgrade (MW)	0	0	5	3
Wind farm-Heat pump cable rating (MW)	-	2.5	-	2.5
Total multi vector system cost saving (£/% of single vector cost)	-	21,235 (1%)	-	89,420 (41%)

The results show that curtailment levels drop as wind farm capacity is reduced; it is less likely for the lost revenues to justify the reinforcement cost:

- For the 7.5MW wind farm examined, some of the otherwise curtailed electricity is utilised by the district heating system without affecting its sizing, which remains the same as in the single vector scenario. Given the low total system benefit of £21k, building a cable is not a viable option unless the two systems are only a few hundred meters from each other (two systems at such a short distance from one another makes the original scenario unrealistic; would be more likely for them to be connected to the same primary substation in which case, there would already be a physical connection between them).
- On the other end, a wind farm twice as big as the one in the Base Case faces greater curtailment, and therefore higher lost revenues, which justify investment in network reinforcement (to allow for the export of electricity to the grid) in both the single vector and multi vector cases.
- The multi vector system benefits from being able to utilise the energy that would otherwise be curtailed to power the heat pump, avoiding the import of electricity from the grid which would incur network loss costs. This is achieved while reinforcing the transformer at a lower level in the multi vector relative to the single vector case, which leads to further savings, though even here the cost savings are only sufficient to make the interconnection of the two systems viable when these are slightly over 1km apart.

It should be observed that for the sensitivities tested, the sizing of the district heating supply technologies does not vary with the wind farm size; it seems determined by the heating network size, and the 1-in-20 peak provision constraint.

Sensitivity to Heating Demand Levels

We next consider how the results vary with the district heating system demand level. Below we present the results of the same analysis as before, but considering 50%, 75%, 200% and 1000% of the original Base case heating demand.

Table 69-Sensitivity to heat demand level results

	Sensitivity 2- Scaled Heat Demand							
	Single Vector	Multi Vector	Single Vector	Multi Vector	Single Vector	Multi Vector	Single Vector	Multi Vector
Heat demand scaling factor	0.5		0.75		2		10	
Heat pump capacity (MW)	5	5	8	8	20	20	102	102
Heat storage volume (MWh)	26	26	39	39	103	103	514	514
Heat Storage discharge / charge rate (MW)	8	8	11	11	30	30	153	153
Total Wind Generation Curtailed (MWh)	760	342	760	258	760	156	760	118
Transformer rating upgrade (MW)	0	0	0	0	0	0	0	0
Wind farm-Heat pump cable rating (MW)	-	1.3	-	1.9	-	5	0	15
Total multi vector system cost saving (£/% of SV cost)	-	35,667 / 76%	-	48,005 /9%	-	72,041 /2%	-	82,350 / 0.5%

The first observation is that the model scales

- the heat pump capacity,
- storage volume, and
- charge/discharge rates

to meet the specified district heating demand.

It simultaneously ensures the combined output from the heat pump and storage is sufficient to respond to the 1-in-20 heat demand value, which is also scaled appropriately for this exercise.

Increasing the total heat demand reduces the level of curtailment, as the district heating system can absorb higher levels of wind generation. No additional multi vector storage is built however; only the surplus wind generation which can be accommodated without changes to the sizing of the district heating facilities is absorbed by the district heating system, since the annualised cost of building additional heat pump or storage capacity is high relative to the savings from not curtailing wind energy.

The multi vector configuration becomes more favourable as the size of the district heating system increases, though the maximum multi vector benefit is dictated by the level of wind generation surplus available to be absorbed by the district heating system. We note that in the scenario where the demand size is 10 times the base case demand, some generation remains curtailed, though as it corresponds to times of zero prices, it is effectively of no system value.

We conclude that for a given level of initial wind curtailment, increasing the size of the heat demand does not lead to sufficiently high system benefit to justify investing in a cable to connect two systems more than 1km away from each other.

Sensitivity to Transformer Reinforcement Capex

The sensitivity of the results to transformer reinforcement investment costs was also investigated by lowering the costs to 75% and 50% of their Base Case values. In the single vector scenario, the lower the capex cost, the higher level of reinforcement is observed, allowing for the system to increase its revenues from electricity generation and reduce curtailment.

In the multi vector scenario, the same fraction of the wind generation surplus is absorbed by the district heating system without affecting its sizing or the need for reinforcement, leading to lower total system costs. However, the multi vector benefit drops with the network reinforcement cost, as it now brings lower savings compared to the single vector scenario.

Sensitivity to District Heating System (Heat Pump and Heat Store) Capex

The sensitivity of the results to a reduction in district heating system costs -the heat pump and heat storage - was also examined by lowering these costs to 75% and 50% of their Base Case values. The results indicate that a capex reduction within that range does not offer a material benefit - the sizing of the district heating technologies and the residual curtailment in the multi vector case remain the same across all sensitivities.

We conclude that per capacity-unit capital costs remain high compared to the extra revenues that the system receives by utilising surplus wind generation, and hence optimum system point includes some residual curtailment, rather than increasing the size of the heating technologies.

Sensitivity to The Price Margin Paid by Heat Pump for Importing Electricity from The Grid

The primary objective of this analysis is to assess the multi vector configuration relative to its single vector counterfactual, adopting a policy-agnostic approach. Interconnecting the wind farm and heat network and operating them in concert offers system benefit through avoided losses on the distribution and transmission networks - this value is a whole system saving, irrespective of policy mechanisms and specific charging regimes.

However, it is interesting to understand the perspective of individual parties, e.g. private owners of the heat network and wind farm, on multi vector operation. Per the current charging regime, the electrical import cost to the heat pump operator comprises not only the wholesale price and charges representing the network losses, but a further margin to account for:

- the costs of using the distribution and transmission networks per unit of energy consumption,
- the supplier margin
- other policy-related costs,

some of which could be avoided if the district heating system was supplied by the wind farm via a private wire.

The effect of including such operator savings has been investigated by varying the percentage margin added to the wholesale price (the margin corresponding to network losses is unchanged at 5% in all cases). The operator saving margin is effectively 0% in the Base Case scenario, increasing it to 20%, 50% and 100% of the wholesale electricity price yields the results shown in the table below.

Table 70-Sensitivity to Electrical Price Margin Paid by the Heat Network Operator

	Sensitivity 3 Electrical Price Margin Paid by the Heat Network Operator					
	Single Vector	Multi Vector	Single Vector	Multi Vector	Single Vector	Multi Vector
Margin (%)	20		50		100	
Heat pump capacity (MW)	51	51	51	51	51	51
Heat storage volume (MWh)	10	10	10	10	10	10
Heat Storage discharge/charge rate (MW)	15	15	15	15	15	15
Total Wind Generation Curtailed (MWh)	760	221	760	221	760	221
Transformer rating upgrade (MW)	0	0	0	0	0	0
Wind farm-Heat pump cable rating (MW)	-	2.5	-	2.5	-	2.5
Total multi vector system cost saving (£/% of single vector cost)	-	162,832 (14%)	-	324,542 (25%)	-	593,192 (37%)

The results indicate that the electrical import price margin paid does not affect:

- the residual wind curtailment, or
- the sizing of the district heating system components, or
- the maximum flow on the interconnecting cable.

In other words, the avoidance of the margin within the range examined is insufficient to incentivise the building of a larger district heating system, as the savings do not outweigh the investment costs.

However, the total system cost saving is greatly influenced by the margin imposed on the heat pump import price. The higher the margin, the more savings the multi vector configuration can bring and therefore, the more incentive the private owner of the system has to invest in an interconnecting cable at greater distances between the two systems. This arrangement benefits the heat pump operator only; the operator of the wind farm sees the same curtailment as in the Base case multi vector scenario.

Despite not representing a system saving, there may be a financial incentive for private owners to invest in such private multi vector arrangements.

The avoided system costs associated with energy lost through long distance transmission pay for less than one kilometre of HV cable. Private wire connections between extant wind farms and heating schemes do not create substantial societal benefit (though they may play a part in financing either or both).

3.6.5 Key Findings

The main conclusions that can be drawn from the analysis presented above are:

1. In the single vector case, the most cost-effective solution is to curtail the wind production rather than invest in a higher-rating transformer to effectively export it to the grid; higher-capacity wind farms experience greater levels of curtailed energy, and reinforcing the transformer becomes a sensible solution as the cost of curtailment exceeds that of the investment in a higher-rating transformer.
2. Multi vector configuration allows a district heating system to use excess generation to produce and store heat; reducing reinforcement and allowing the system to avoid the costs incurred as network losses when electricity is instead imported from the transmission system.

   The multi vector benefit increases with the size of wind farm, i.e., with the level curtailment; by supplying more energy to the heat pump, the multi vector configuration offsets the import of electricity at higher network loss costs. However, for wind farms of the size modelled – below 15MW - the multi vector benefit only justifies the interconnector installation for distances of around 1km.
3. The sizing of the district heating plant - the heat pump and storage - is determined mainly by total thermal demand and the 1-in-20 peak requirements. In none of the scenarios assessed did the model increase the multi vector sizes of these technologies to enable the use of more wind energy. This indicates that the cost of building an additional unit of capacity for those heating technologies outweighs the benefit of avoiding network costs. Thermal plant sizing was found not to be sensitive to credible scenarios of capex reduction for those technologies either, for the same reason.
4. The larger the district heating system, the more surplus wind generation can be utilised to offset heat pump electrical imports from the grid and hence, the greater the multi vector benefit. Nonetheless, these were still found to be sufficient only to justify installation of an interconnector a few kilometres long.
5. From the perspective of heat network operators, there may be material benefit in an interconnecting cable if the margin imposed on the electricity imports from the grid is between 20% and 100% of the wholesale price. Despite this providing no benefit at the energy-system level, it could incentivise private owners to invest in such multi vector configurations.

3.6.6 Operational and Engineering Impactions

This analysis as considers the case of wind generation curtailed due to distribution network constraint, and finds that while there is some system benefit in supplying electricity that would otherwise be curtailed to a nearby heat pump power district heating system, the level of benefit is sufficient only to justify transmitting electricity from the wind farm a relatively short distance via a private wire electrical network (< 1 km). While the system benefit is limited, mainly derived from the reduction in distribution losses associated with the electricity the heat pump imports from the grid, the potential value to the operator of the heat network could be significant; depending on:

- the scale of the network and electricity market charges,
- the supplier margin that the district heating system operator can avoid by taking electricity from the local wind farm (also, the price that the local wind farm operator is happy to receive for electricity that would otherwise be curtailed may be lower than the wholesale price).

Hence there may be a local benefit to the private operators that would justify investment in a private wire to connect renewables on constrained networks to district heating systems, potentially over longer distances than was found to be justified by system benefits.

The technical and operational issues associated with the system configuration described in the case study appear to be very few. The wind farm operator would have a non-firm connection agreement with the local DNO, allowing the DNO to curtail the wind farm at times of network constraint, e.g. by sending a signal as part of an active network management system. At this point the wind farm is disconnected from the local distribution network, and the private electrical circuit feeding the district heating system is energised. The private wire network feeds electricity to the heat pump via a connection point located 'behind-the-meter', i.e. on the heat pump side of the electricity supplier MPAN, thereby reducing the amount of electricity the heat pump imports from the grid.

Note that in the Case Study example, the heat pump is connected to a separate electricity distribution network circuit to the constrained circuit that the wind farm is connected to. The private wire network, once constructed, may therefore provide an opportunity to export electricity to the grid at times that the wind farm is curtailed but that there is no simultaneous demand for heat on the heat network (or thermal store).

The operation of the district heating network is unchanged as a result of the supply of power over the private wire rather than the local grid. In the case study, increasing the size of the thermal store to further reduce the level of wind curtailment was not found to be economic, although in the case that the avoided grid charges and supplier margins are higher there may be a financial incentive for the district heating system operator to invest in a larger thermal store.

Wider case for Power-to-heat

While the case study presented here has not found a strong system benefit for power-to-heat in the case of a wind farm on a constrained electricity network, there is considerable interest in power-to-heat as a balancing technology in a number of European countries, particularly those with high levels of RES penetration and significant heat supplied by district heating. Studies of the Danish power system, for example, have identified power-to-heat as a cost-effective method of balancing intermittent renewable generation, considering a wind farm supplying electricity to an existing heat pump based district heating network. Studies in Denmark and other European countries have often focussed on electric boilers in power-to-heat systems, finding that while heat pumps provide a greater system benefit for the same heat output, the much lower cost of electric boilers leads to a higher ratio of benefits to costs.

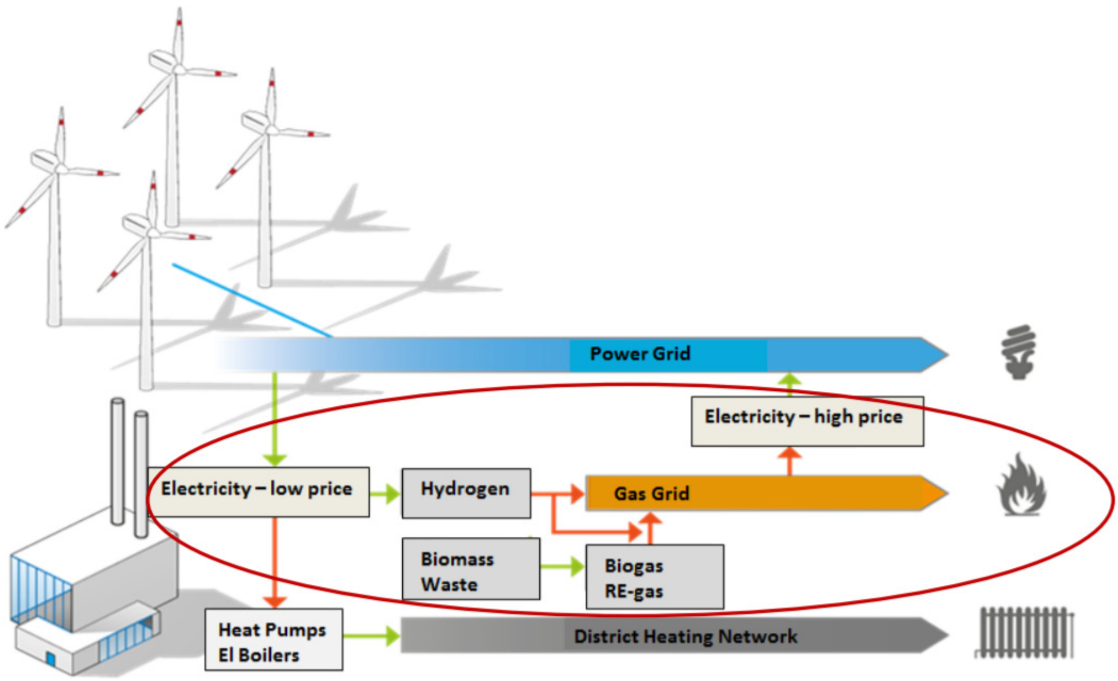

Figure 57, Danish district heating vision – a multi-vector approach[85]

Much of the interest in power-to-heat in European countries such as Denmark and Germany has focussed on its potential to consume electricity during times of surplus, i.e. when there is significant renewable generation on the system and low electricity demand, rather than as a means of avoiding network constraints. In these countries, a large amount of the district heating system thermal plant is CHP, hence substituting a part of the CHP generation with heat produced by electric boilers or heat pumps also has the advantage of reducing CHP electricity generation at times of generation surplus.

A study of the potential for power-to-heat in Germany predicted that by 2030 there could be a technical potential for 8.5 TWhe of electricity to be used to provide heat to district heating systems[86], based on the correlation between negative residual load on the electricity system and thermal demand on German district heating networks. Despite the large technical potential, it was only found to be economic to use power-to-heat in Germany to provide frequency response. The component of the German electricity price related to grid charges, feed-in tariff and taxes, meant that it was not economic to use excess power for power-to-heat.

German and Danish studies have found that power-to-heat offers considerable technical potential to balance surplus renewables in systems with large renewables penetration, however the economics of power-to-heat are undermined by grid charges and other components of the electricity price (even when the wholesale price is low). The authors of these studies believe there is a case for incentivising the use of electricity for heat during times of negative residual demand on the system.

[85] Danish Energy Agency, District Heating and Integration of Wind Power in Denmark

[86] Potential of Power-To-Heat Technology in District Heating Grids in Germany, Böttger et al, Energy Procedia, vol. 46, 2014

3.7 Case 6b: Smart Electric Thermal Storage (SETS)

3.7.1 Introduction

Context

Around 10%[87] of UK homes are not connected to the gas grid, particularly those in sparsely populated areas or isolated communities - the fraction is higher in Scotland and Wales. Of these:

i. 800,000 are heated by oil,
ii. 1.8m are heated using electric storage heaters[95], and
iii. 600,000 using other resistive heating[88].

Some off-gas-grid areas have significant renewable energy resources but weak electrical grids; making the development of renewable generation prohibitively expensive. A 2014 Community Energy Scotland (CES) assessment estimated that:

> 65% of community energy projects in Scotland cannot gain a firm grid export connection for their planned installed capacity, because of unaffordable grid constraints.[89]

In one such isolated community, the Isle of Mull, the potential for aggregated domestic electric heating to offer distributed demand response has been investigated in the Access Project. The island's 50kW export constraint is mitigated by management of the aggregate electric heating demand of 100 homes, allowing a greater fraction of a 180kW hydro plant's generation to be used. A similar scheme, Heat Smart, looks at mitigating curtailment of a 900kW wind turbine on Orkney.

At larger scales, distributed electrical heaters and storage can help mitigate regional or system level oversupply, and provide ancillary services; regulators, suppliers, aggregators and housing associations are beginning to investigate potential business models for multi-megawatt-scale domestic generation matching.

A total of around 15 GW of electrical heaters in the UK produce around 25TWh of domestic heat each year[90] - equivalent to the total wind generation capacity installed in the UK and half their output respectively. Given:

i. the large number of new build homes in construction that will be warmed using panel heaters,
ii. the increasing uptake of heat pumps,

total installed capacity of domestic electric heating plant is expected to continue to rise beyond 2050. Electrification of heat may then provide an increasing reservoir of manageable demand which can be matched to renewable generation, or provide grid regulation services.

Case Study Aims

In this Case Study, we assess the potential for SETS to:

1. Increase the utilization of, and so lower the barriers to, renewable generation in grid constrained areas.
2. Provide ancillary services to grid operators and DSOs.
3. Lower the costs of low-carbon, off-grid heating.

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[87] Sub-national estimates of households not connected to the gas network
[88] United Kingdom Housing Energy Fact File 2013
[89] About Local Energy Economies: The potential for Scotland, CES 2014
[90] Energy consumption in the UK

We note that price optimisation through domestic DSM is not considered as part of this study, and that we do not consider forward planning of thermal demand matching, so that our analysis may underestimate the benefits of SETS.

3.7.2 Potential Scale and System Value of SETS

Local Demand Matching for Network Management

The UK's Renewable Energy Planning database includes over 500 projects between 1 and 30 MW in size (totalling 3.7 GW), with planning permission but awaiting construction; many of these face economic viability hurdles due wholly or in part to lack of grid capacity. DNO connection capacity maps show that most distribution lines are highly constrained; examples for Scottish Power Energy Networks 11kV and 33kV lines are shown below, (the interactive map can be seen here[91]). In the south, and coastal regions, of England, megawatt-scale wind and solar projects are occasionally curtailed, and new projects struggle to find the network headroom required to connect.

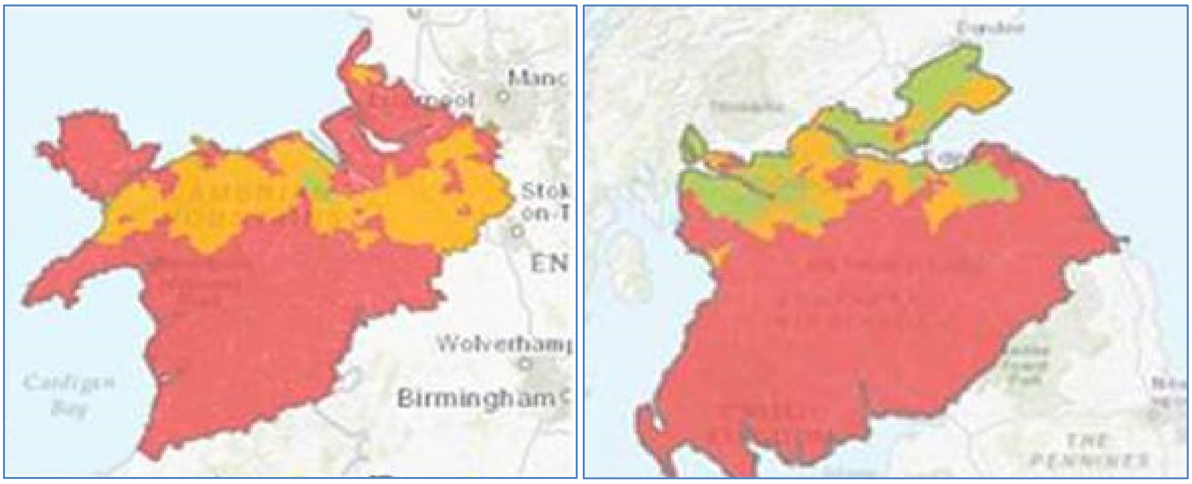


Figure 58 - SP Energy Networks - Connection Constraint Heat Maps, North Wales & Scottish Borders.

Local clusters of smart, electrically heated homes represent a potential means of alleviating this curtailment through active network management (ANM); matching demand to supply to reduce net flow on constrained circuits to within operational limits.

SETS may therefore enable grid connection, and increasing utilisation, of community owned projects. These projects are a key part of the drive to alleviate fuel poverty in isolated areas, where up to 70% of local people may be in fuel poverty while local renewable generation is curtailed on a daily basis. Scotland plan to meet 1.5 TWh of heat – the demand of around 100,000 homes - from DH by 2020[92]. SETS - also called Virtual District Heating (VDH) – is expected to make-up a large fraction of these (other community scale projects consider means other than thermal store – such hydrogen electrolysers at Surf 'n' Turf Orkney[93] – to avoid local grid constraints).

[91] SP Distribution Heat Maps

[92] The Heat Policy Statement - Scottish Government

[93] Orkney Surf 'n' Turf

System Level Services

Much of the 15GW of electric heating is distributed across the country, and connected to different gird circuits; it cannot reduce net flow, though it may provide ancillary services and system level demand matching.

Turn Up

To address issues of system level renewable oversupply, in May 2016 National Grid soft-launched the Turn-Up Service, under which users are paid for their ability to turn generation down or demand up during off-peak periods. The scheme seeks to address:

- A large increase in distribution-embedded Solar PV driving a suppression in demand levels during the day
- [significant variation in] overall wind levels overnight and during the day[94]

Turn-Up offers an hourly availability payment during summer of around £1.50/MW; at 80% availability, this corresponds to a total value of £2250/MW/year.

Table 71 - Turn-Up Service – Required Availability

Months	Overnight	Day
May and September	23:30 to 08:30	13:00 to 16:00
June, July and August	23:30 to 09:00	13:00 to 16:00

SETS constitutes a potential source of Turn-Up, although:

i. National Grid expects only around 300MWh to be required annually in the short term
ii. Domestic summer heat demand is low, so that large numbers of households would have to be connected to mitigate unit PV oversupply.

Grid Regulation

Electric heaters represent an excellent source of frequency regulation services, at least in winter, as:

i. They can be ramped up and down without affecting user experience.
ii. Resistive heaters have few moving parts, and while most heat pumps require further design iterations to meet dynamic frequency response requirements, there are no technical barriers to developing their frequency responsive capabilities.

V-Charge are working with National Grid on a study into Fast Dynamic Frequency Response - an advanced form of EFR - in which 60MW of modern storage heaters respond within two seconds to a continuous control signal, thereby regulating mains electrical frequency[95]. An Element Energy report for National Grid[96] found that subject to the resolution of control and response time concerns, the value to a domestic heat pump of frequency provision is around £51 annually; storage heaters would likely see similar value.

[94] National Grid - Demand Turn Up

[95] V-Charge Consultation Response to Ofgem

[96] Frequency Sensitive Electric Vehicle and Heat Pump Power Consumption

EFR strike prices at the June 2016 auction range between £7.5/MW/h and £12/MW/h; representing between 12 and 20 times the value of Turn-Up, as technical requirements are more stringent, and the availability payment is offered for the entire year.

Suppliers are also starting to look at SETS as a means of managing imbalance, including the SSE Real Value Project.

3.7.3 Scenario Definitions and Assumptions

This Case Study considers a distributed network of storage and immersion heaters, or electric boilers, controlled centrally to mitigate a renewable generation export constraint.

Three scenarios are modelled:

1. A community-scale hydro facility on a remote island.
2. A wind farm of 12MW and development of modern housing blocks in a nearby town.
3. A 4MW solar farm in south west England

Table 72 – Scenario Definitions - Generation and Constraint Sizes

Scenario Name	Generator Power	Export Constraint	Homes on Constraint side
Hydro (Scottish Islands)	180kW	50kW	100
Wind (Scottish Borders)	12MW	4MW	4,000
Solar (West Country)	4MW	2MW	2,000

Housing Archetypes

The breakdown of house types, and their space, hot water and electrical demands are taken from the Scottish Housing Condition Survey 2011-13, with space heat demand totals scaled to the local climatic conditions for each scenario.

Thermal Demand

Daily thermal demand is based on an annual demand total scaled to the number of 15.5°C heating degree days (HDDs) for locations around the country[97].

Table 73 - 15.5°C Heating Degree Days by Location

Scenario Name	Location	Total 15.5°C HDDs
Hydro	Scottish Islands	3,149
Wind	Scottish Borders	2,330
Solar	West County	1,613

[97] Heating Degree Days are a measure of the aggregate difference between the baseline and the actual outdoor temperature, given by the total temperature difference multiplied by the number of days.

Electrical Heating

Electric boilers are used in much the way that gas boilers are, heating water for space heating and domestic hot-water. Model boilers are sized, for each residential archetype, to 1,000 run hours - around 12kWe for an average UK residence, and while electric boilers can meet instantaneous demand, they can store 180 litres hot water for later use. Domestic thermal and hot water demand profiles are described in appendix 8.1.1.

Storage and immersion heaters are typically run on a time-of-use (ToU) electrical tariff, such as Economy 7 or Economy 10; generating and storing heat during periods of low electrical demand at cheaper rates, and releasing this heat into the building as required.

For each property and location, model storage heaters are sized to the Economy 7 off-peak period - 7 hours - for half the year; heater ratings are given by total annual demand divided across 1275 hours. Hourly demand profiles are given by distributing daily thermal demand uniformly across the off-peak run hours, with electrically heated homes split evenly between the Economy 7 and Economy 10 tariffs.

Storage heater users are assumed to use immersion heaters to provide their hot water demand, which they operate in the same way; model storage heated properties therefore generate no thermal demand outside off-peak hours. Houses heated by electric boilers use the instantaneous demand profile, though these are included only in the Constrained Hydro scenario.

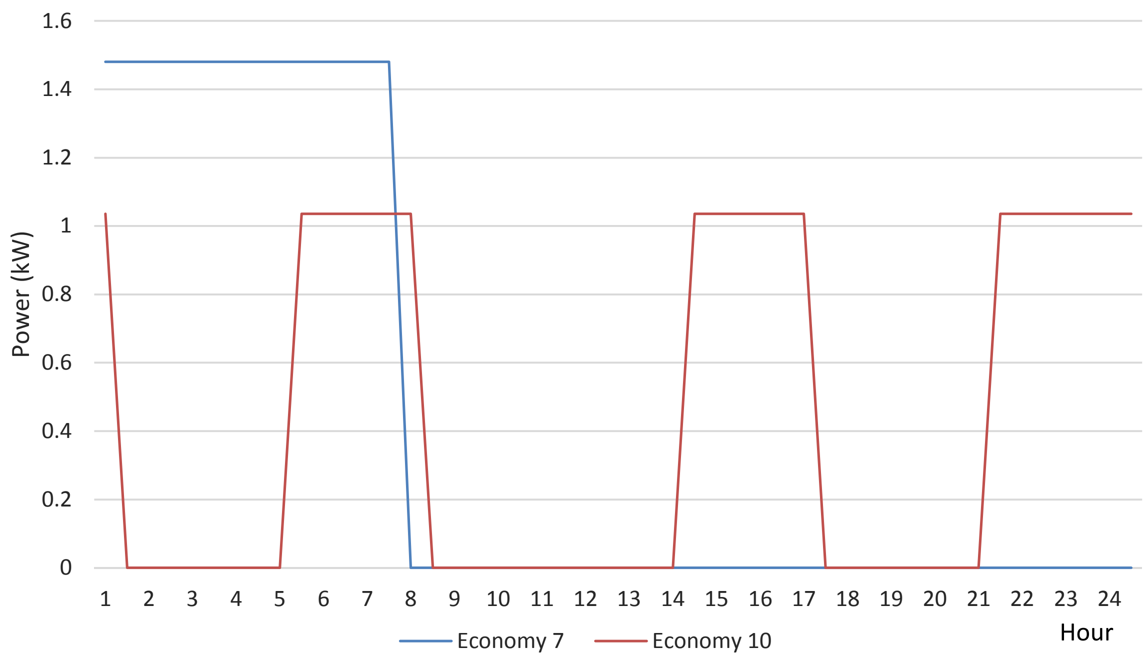


Figure 59 – Diurnal Winter Heating under Economy 7 and Economy 10 ToU Tariffs

Electrical Appliance Demand

Non-thermal electrical demand located behind the grid constraint can also be specified in the model. The hourly load shape is taken from aggregate primary substation half hourly data, the peak demands specified are shown below.

Table 74 – Electrical Demand behind Export Constraint

Scenario Name	Peak Appliance Demand (kW)	Storage Heated Homes	Homes with Electric Boilers
Hydro	0	15	85[98]
Wind	1,000	4,000	0
Solar	500	2,000	0

Electrical Price Time Series

Electrical time series prices are taken from the 2020 ESME High Decarbonisation Scenario, at an average wholesale price of £39/MWh. SETS stores renewable oversupply as heat whenever capacity exists and these prices are positive - no further price optimisation is considered in the model, and customers do not move their demand away from high price periods. The total value of additional generation may however depend on this price series, and the average price at times of demand management may differ from the annual average.

Since this Case Study considers system level value, wholesale - rather than domestic flat rate or ToU – electrical prices are used.

Carbon Price

Where renewable generation can be stored, it offsets supply of thermal electric demand at the grid average carbon intensity of 0.255 tonnes CO_2/MWh. The electrical price time series includes a carbon component, and therefore reflects the environmental benefit of capturing renewable generation (these carbon prices are significantly below those in the BEIS Central Scenario[99]; although both aim to reflect the marginal abatement cost).

However, policy instruments that incentivise low carbon heating may pay scheme operators or participants for using zero carbon power through e.g. the RHI; the carbon value, at the BEIS Central 2020 price difference of £45/tonne is therefore also reported.

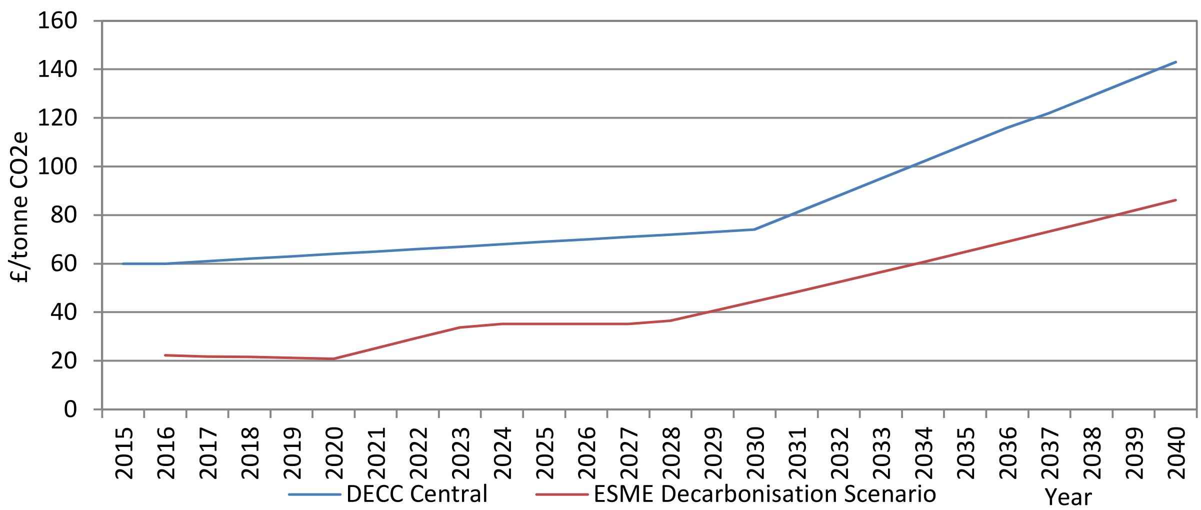


Figure 60 - BEIS and ESME Decarbonisation Scenario Carbon Prices

98 Electric boilers are used on Scottish Islands, but are relatively rare elsewhere in the UK.

99 A brief guide to the carbon valuation methodology for UK policy appraisal

System Cost

In current field trials of SETS and other domestic heat demand management, monitoring and telemetry systems were retrofitted to scheme participants' thermal plant. Given this, and the modest number of trial subjects, user participation costs were considerably higher than project revenues.

An estimate of the SETS infrastructure costs at scale is taken from the Element Energy study for National Grid *Frequency Sensitive Electric Vehicle and Heat Pump Power Consumption*, which calculated annualised control costs at £20 per user – here, we use this cost for storage and immersion heaters, and electric boilers. Where retrofit is required, annualised connection and monitoring user costs are likely to be substantially higher.

Glen Dimplex, who supply most of the UK storage heater market, report the cost of modern, aggregator-ready heater as between £1,000 and £1,500 for new build, or up to £3,500 to retrofit or refurbish in existing buildings. Honeywell offer a smart immersion heater, the combined installation, system and control cost of which is below €400.

As the multi vector solution and the single vector alternative (BAU curtailment) use the interconnector and existing LV network within their design parameters, SETS does not introduce any additional DNO costs; grid use charges are therefore not included in this analysis.

Thermal Losses

Energy in a storage heater is dissipated to the environment; when there is no household thermal demand, this dissipated heat has little value to the consumer. Some fraction of the additional renewable generation converted to heat will not be usefully deployed; particularly if the thermal reservoirs are filled at times of little demand e.g. during high summer.

Model storage heaters and hot water tanks lose between 1-2% of their stored heat at each model time step, where these losses do not coincide with thermal demand they effectively have no user value. To capture the user benefit of SETS, the model reports both the amount of renewable generation that is stored as heat, and the fraction that is then usefully deployed (this lower bound on useful energy is reported as the Useful Heat Fraction).

Hourly Generation Data

Capacity factor data for hydro and wind generation are taken from Gridwatch data, while solar generation data are taken from *PVsyst*[100] for the UK; daily hydro and wind generation are correlated with thermal demand, while solar generation and thermal demand are negatively correlated. The model stores heat when there is capacity; much of the heat generated in summer will therefore be lost to the environment, leading to lower Useful Heat Fractions.

Table 75 - Correlation of Daily Generation and Thermal Demand

Scenario Name	Correlation with Thermal Demand
Hydro	0.47
Wind	0.66
Solar	-0.68

[100] PVsyst is a software package for solar plant annual load calculation.

3.7.4 Case Study Analysis

For each scenario presented above, we determine the system level value of electric heating as both an unmanaged and a managed demand in reducing renewable curtailment:

- In the former case storage heaters are run at constant power across their off-peak hours and electric boilers are run to meet instantaneous demand, using local generation preferentially.
- In the latter case, generation which would otherwise be curtailed is used to generate domestic heat which is then stored (provided there is sufficient capacity).

Scenario 1 - Hydro

Parameters for the community scale **Hydro** scenario are given below.

Table 76 – Model Parameters – Hydro Scenario

Parameter	Value
Generator Nameplate	180kW
Export Limit	50kW
Generation Load Factor	37%
Peak Thermal Demand	280kW
Peak Appliance Demand	50kW
Useful Heat Fraction	70%

Model results are shown in Table 77; in this case:

- 31% of renewable generation is used by local domestic appliances (9%) or exported to grid (22%)
- 54% of generation is consumed as unmanaged electric heating.
- A further 12% can be matched by smart management of thermal demand, so that only 4% of generation is curtailed.

Table 77 – Hydro Scenario - 2020 Electrical Generation and Supply

	Total Generation	Exported or Used Locally	Supplied as Electric Heat	Matched using SETS	Curtailed
Total Power (MWh)	585	179	313	71	21
Share of Total		31%	54%	12%	4%
Electrical Value (£)	23,298	7,688	12,702	2,279	629
Share of Total		33%	55%	10%	3%
Wholesale Cost (£/MWh)	39.8	42.9	40.6	32.1	29.4

Of the heat that is demand managed and stored, 30% is dissipated - slightly above typical values for storage heaters. The customer value will therefore not reflect the full price of the electricity. We therefore report, below, the total generation value, and that value scaled by the 70% Useful Heat Fraction; the scaled and unscaled values represent lower and upper bounds on the smart multi vector value respectively.

Table 78 - Annual Hydro Scheme SETS Total Value

	Total	Per User	Per kW
Total Solution Value	£14,981	£149.81	£47.04
Total Solution Value scaled by Useful Heat Fraction	£10,541	£105.41	£33.10

Table 79 - Annual Hydro Scheme SETS Smart Management Value

	Total	Per User	Per kW
Smart Management Value	£2,279	£22.79	£7.16
Smart Management Value scaled by Useful Heat Fraction	£1,604	£16.04	£5.04

In the **Hydro** scenario, behind constraint electric heating is worth over £100 per user per year – around £40 per kW per year - in avoided renewable curtailment.

The premium for monitoring and telemetry required to enable smart management of this demand may be recouped, though at an annualised system cost of £20 per user, insufficient value may remain to incentivise customer participation, once this margin is shared between the aggregator and generator.

The value of the SETS has a similar per kW system level value of frequency response provision; where control systems and aggregation platforms allow the provision of both services, control and monitoring system costs will be more rapidly recouped.

Environmental Value

The value of the emissions avoided through renewable supply is shown below; a low-carbon heat subsidy in line with the BEIS Price and Carbon Intensity projections, increases the SETS value by around 35%; sufficient to increase the lower bound of per user value to above the £20 control system cost.

Table 80 - 2020 Hydro SETS Environmental Value

	Total Generation	Exported or Used Locally	Supplied as Electric Heat	Matched using SETS	Curtailed
Carbon Emissions Avoided (tonnes)	149	46	80	18	5
Emissions Value (£)	6,410	1,965	3,433	777	234
Carbon Value Fraction of Fuel Saving	28%	26%	27%	34%	37%

Small scale water-power schemes on isolated grids can profitably reduce their curtailment by control of local storage heaters and (particularly) electric boilers; the capital costs of which are low.

Scenario 2 – Wind

Parameters describing the **Wind** scenario, and model results, are tabulated below.

Table 81 – Scenario Parameters

Parameter	Value
Generator Nameplate	12MW
Export Limit	4MW
Generation Load Factor	32%
Peak Thermal Demand	6,400kW
Peak Other Demand	1,050kW
Useful Heat Fraction	50%

At the 12 MW wind farm modelled:

- over 50% of generation is curtailed where no electric heating load is present behind the constraint
- connecting 4,000 electrically heated flats behind the 4MW export constraint reduces these shares to 34% and 13% for unmanaged and managed use of storage heaters respectively.

Only 50% of heat is usefully deployed - considerably lower than for typical storage heater operation – these losses arise where heat is stored for long periods with little demand, e.g. over summer.

As storage heaters normally charge at off-peak times, smart matching moves this demand to times of higher prices; the mean value of matched generation is therefore 15% above average. Customer participation would likely be contingent on some guarantee of reduced, or at least no increase in, net fuel bills.

As electric boilers are not included in this scenario, there is no unmanaged electric heating demand during peak hours; the smart management capability therefore represents a much greater share - over half – of the multi vector benefit than in the **Hydro** scenario; and value remains to incentivise customer and generator participation once control costs have been met.

Table 82 – Wind Scenario - 2020 Electrical Generation and Supply

	Total Generation	Exported or Used Locally	Supplied as Electric Heat	Matched using SETS	Curtailed
Total Power (MWh)	33,343	16,502	5,601	6,748	4,492
Share of Total		49%	17%	20%	13%
Electrical Value (£)	1,379,130	662,740	193,430	325,530	197,430
Share of Total		48%	14%	24%	14%
Wholesale Cost (£/MWh)	41.4	40.2	34.5	48.2	44.0

Table 83 - Annual Wind Scheme Total SETS Value

	Total	Per User	Per kW
Total Solution Value	£518,959	£129.74	£73.09
Total Solution Value Scaled by Useful Heat Fraction	£253,614	£63.40	£35.72

Table 84 - Annual Wind Scheme Smart Management Value

	Total	Per User	Per kW
Smart Management Value	£325,527	£81.38	£45.85
Smart Management Value Scaled by Useful Heat Fraction	£159,084	£39.77	£22.41

Environmental Value

The environmental value of the smart heating system raises the value of the scheme by around 25%; a premium of £25/year for electric heating, and £15/year for the SETS platform.

Table 85 - 2020 Wind SETS Environmental Value

	Total Generation	Exported or Used Locally	Supplied as Electric Heat	Matched using SETS	Curtailed
Carbon Emissions Avoided (tonnes)	8,516	4,215	1,431	1,724	1,147
Emissions Value (£)	365,556	180,916	61,412	73,984	49,244
Carbon Value Fraction of Fuel Saving	27%	27%	32%	23%	25%

Wind power schemes can reduce curtailment by more than half by connecting to a flexible demand bank of half their size, and in so doing create local value. The value of the electricity that can be absorbed using SETS comprises an additional 40% on unmanaged power sales. At around £80/user/year, the value of SETS is likely insufficient to pay for new storage heaters, it is therefore likely to be limited to new build homes or existing users of storage heaters.

Scenario 3 – Solar

The key parameters for the **Solar** scenario are shown below, model results are shown in Table 87. Here:

- 70% of generation is curtailed.
- Given the distribution of solar generation, only a small fraction (6%) of generation can be absorbed to typical off-peak electrical heating
- SETS doubles the generation that can be absorbed, though only half of the stored heat is later used to meet consumer thermal demand.

The first finding is driven by the high seasonal and diurnal concentration of generation, the second and third point to the mismatch in summer PV output and thermal demand (as a result, useful heat fractions are similar in the **Solar** and **Wind** scenarios, but **Solar** curtailment is higher (24% against 13%) even though there is more domestic heat demand per kW of generation than in the **Wind** case).

Table 86 – Scenario Parameters

Parameter	Value
Generator Nameplate	4MW
Export Limit	1MW
Generation Load Factor	24%
Peak Thermal Demand	2,860kW
Peak Other Demand	525kW
Useful Heat Fraction	49%

Table 87 – Solar Scenario - 2020 Electrical Generation and Supply

	Total Generation	Exported or Used Locally	Supplied as Electric Heat	Matched using SETS	Curtailed
Total Power (MWh)	8,266	2,480	494	3,271	2,022
Share of Total		30%	6%	40%	24%
Electrical Value (£)	325,318	98,736	18,539	132,491	75,551
Share of Total		30%	6%	41%	23%
Wholesale Cost (£/MWh)	39.4	39.8	37.5	40.5	37.4

SETS values for the **Solar** case are shown below:

Table 88 - Annual Solar Scheme Total SETS Value

	Total	Per User	Per kW
Total Solution Value	£151,030	£75.52	£51.20
Total Solution Value scaled by useful heat fraction	£73,386	£36.69	£24.88

Table 89 - Annual Solar Scheme Smart Management Value

	Total	Per User	Per kW
Smart Management Value	£132,491	£66.25	£44.92
Smart Management Value Scaled by Useful Heat Fraction	£64,378	£32.19	£21.83

In the solar case, generation and thermal demand experience opposite seasonal trends, and the ToU heating demand coincides only marginally with solar generation hours, shown below. Nevertheless, some savings can be realised through intelligent use of thermal storage; the SETS value is around £50 per user per year – £30/kW – and comprises around 80% of the system value of electric heating.

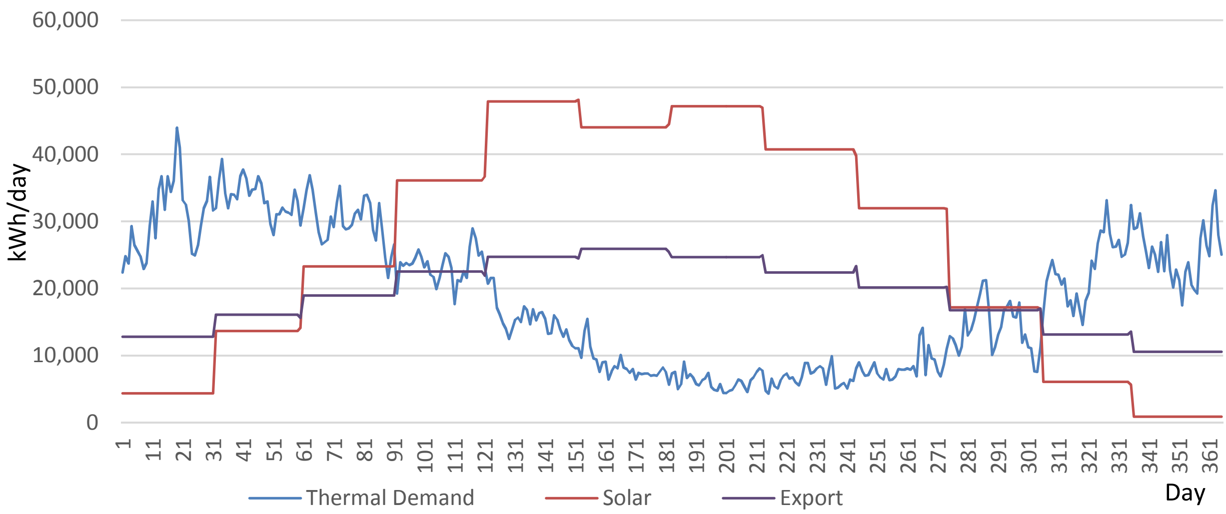


Figure 61 - Solar Generation, Export Potential and Thermal Demand

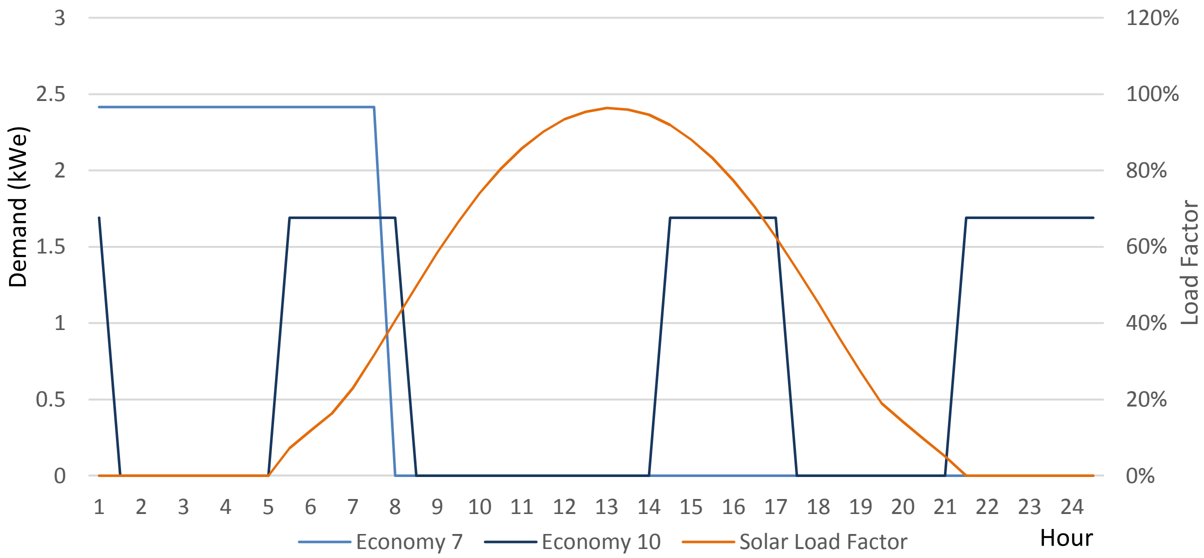


Figure 62 – June Storage and Immersion Heating Demand and Solar Generation Load Factor

Environmental Value

The environmental value of SETS again comprises around 25-30% of the wholesale cost of the additional generation absorbed.

Table 90 - 2020 Solar SETS Environmental Value

	Total Generation	Exported or Used Locally	Supplied as Electric Heat	Matched using SETS	Curtailed
Carbon Emissions Avoided (tonnes)	2,111	633	126	835	516
Emissions Value (£)	90,623	27,185	5,417	35,857	22,163
Carbon Value Fraction of Fuel Saving	28%	28%	29%	27%	29%

Given the lower overlap between demand and generation, SETS appears less well suited to solar oversupply, even under the more generous heat demand to generation assumptions in this scenario. There is however sufficient value for a lean business model to develop SETS as a means of avoiding curtailment of PV oversupply.

Sensitivities

The value of SETS has been investigated for a variety of generators; the effect of model assumptions is reviewed below.

Storage Efficiency

A key factor in the useful storage of renewable generation as domestic heat is the rate at which this heat is lost to the environment; the effect of increased loss rates on useful heat fractions across the three scenarios is shown below.

Figure 63 – Variation in Useful Heat Fraction with Storage Efficiency

Hourly Storage Efficiency	Scenario		
	Hydro	Wind	Solar
98%	70%	50%	49%
96%	58%	30%	35%
92%	50%	20%	30%

Efficiency ranges at the upper end of this range are representative of modern storage heaters, the lower end may be more indicative of legacy units. Existing electric heaters may require replacement before being included in a SETS scheme.

Applicability

Single Vector Alternatives

Curtailment of renewable generation might also be resolved though grid reinforcement or battery storage. At a cost of between £2 and £10/kW, SETS represents a lower cost storage solution than batteries by a factor of between 4 and 20; battery storage appears unlikely to resolve renewable export constraint issues in the medium term.

Costs of network upgrade will depend on:

i. The length and location of the network sections to be reinforced
ii. Any required substation reinforcement

These costs will include both fixed and variable (by kW and by km) components, it is therefore difficult to assess reinforcement as a single vector competitor to SETS. We note however the extent to which grid connection costs prevent the commissioning of UK renewable energy projects, discussed above.

Table 91 – 2020 ESME Battery Cost Data

	Li-On Battery
Capex (capacity) (£/kW)	372
Economic lifetime (years)	15
Cost of capital discount rate (%)	8
Required Return (£/kW)	41

Environmental Value

Storage heaters were initially developed in the 1950's to absorb off-peak nuclear generation, and there is renewed interest in off-peak electric heating as a new generation of fission plants come online. This analysis may overstate the environmental benefit (at least in the **Wind** and **Solar** cases) as overnight and off peak generation are likely to be less carbon intensive than average. Reduction in this value does not however qualitatively alter our findings.

3.7.5 Key Findings

Based on our analysis, the intelligent management of distributed electrical heaters and storage may have a role to play in the mitigation of renewable constraints and provision of ancillary services.

1. Smart electric heating creates energy system value of between £50 and £150 per household per year. Storage heater installed costs for new build are between £1,000 and £1,500 per dwelling, SETS value may be sufficient to drive the selection of electric heating as a heat supply option – giving a distributed source of curtailment mitigation – but not to cover these costs.

   As this value accrues to generators and network operators, developers taking decisions on how to heat new build schemes and homeowners replacing legacy units may require policy incentives that offer them some of the system value of the management of their thermal demand.

2. The fraction of this value due to the smart management of thermal storage depends on the diurnal and seasonal distribution of generation and heat demand, but is between one and two times the control and monitoring premium for new space heaters and boilers. This value must, however, be shared between the generator, aggregator and customers; currently no commercial mechanisms or regulatory frameworks exist to do this, and whether the value is sufficient to incentivise users, once aggregator and generator margins have been met, is unclear.

3. SETS value equates to between £25 and £50/kW, comparable to the strike price of frequency regulation services, which modern storage or immersion heaters might also provide. These are around 10 times the value of the annual Turn -Up payment - worth around £2/kW/year, demand for which is not expected to exceed 300MWh annually. There is also a utilisation payment for Turn Up, worth around £70/MWh, provision value is likely to remain marginal compared to the control system costs.

4. Where SETS connects to buildings with dual time meters and existing electrical heaters, further metering and telemetry will be required, with costs well above the £20 or so envisaged in the National Grid report, and at legacy storage efficiencies, much of the stored heat may be lost. As such, SETS value is unlikely to drive investment in smart management of existing electric heaters in the UK before their upgrade (the lifetime of storage heaters is around 15 years)

5. Communities on constrained grids who build and operate renewable generators may find SETS a low-cost alternative to grid reinforcement or electrical storage, particularly where homes in these communities are electrically heated.

   Although there are substantial logistical and financial costs to aggregation of community demand to lower electrical prices, and to building, operating and demand matching renewable generation, organisations are pursuing these aims, often with a specific focus on fuel poverty.

3.7.6 Operational and Engineering Implications

Challenges associated with the transition to multi vector operation have been collated through consultation with industry stakeholders and other experts, and are summarised in the table below. Further analysis is provided in the accompanying report *Barriers to Multi Vector Energy Supply.*

	Issue	Impact and Solution / Mitigation
Commercial	**A mechanism is required to share generation value with customers who allow their demand to be managed.**	Demand management of heating can lead to heat supply being shifted from off-peak to peak periods, which could lead to increases in consumer bills. Commercial arrangements are therefore required to ensure that consumers benefit (or at the very least, see no increase) as a result of participation. Options could include: **A customer rebate** – customers could be provided a rebate for participation in the scheme. This would be relatively simple to implement, and might not require a change in their tariff. **Local time of use tariff** – A time-varying tariff could be offered by the supplier, which would lower electrical prices at times of high renewable generation. This tariff would ensure that consumers benefit from the management of their demand, although demand management may need to be implemented as direct control by an aggregator, rather than purely based on price signals, to get the required 'firm' DSM response from a potentially limited number of customers. Domestic half hourly metering and settlement would be required for a time-varying tariff. **Pooled demand and generation** – Generation and demand could be pooled within a 'virtual MPAN'. In this case, a local supply company, acting as a licence exempt supplier, would bill consumers based on half-hourly consumption data and a time varying tariff, ensuring participant benefit – the renewable generation and aggregated demand are pooled behind the virtual MPAN, and the local supplier settles their net position with a licenced electricity supplier. **DNO management with a local tariff** – An aggregator manages the demand as a service to the DNO (this could be as part of an ANM scheme), and the DNO recoups cost through an increased GDUoS charge on the generator for generation that would have otherwise been curtailed. In this case the consumers could still be billed by the electricity supplier, but a lower tariff could be offered to participants of the scheme, funded by a reduced payment to the generator for generation that would have been curtailed.

Technical	**In-home systems and communications infrastructure are required to enable the response of demand consumers**	SETS depends on the reliable control of domestic electric heaters. Smart thermostats that manage in-home control enable demand flexibility to be offered (managed by a third-party aggregator) while ensuring consumer comfort is maintained. Enabling heating appliances to provide additional ancillary services, such as rapid frequency response, is likely to require further bespoke hardware (current commercial smart thermostats do not offer this service. Bespoke devices to provide this response, such as those offered by V-Charge, are being commercialised). **Compatibility**–suppliers of smart thermostats that manage in-home comfort and provide longer-term demand shifting are not necessarily the same organisations that provides the demand management platform (e.g. the aggregator). This demand management platform must collect data from the installed smart thermostats on the availability of flexible demand and be able to send control signals to these thermostats. The aggregation platform may analyse past consumption data and weather data to predict future availability of flexible demand (alternatively this could be done at the local device level). Where different organisations are involved, open communication protocols are needed to enable two-way communication between local devices and aggregation platforms. The management of domestic heating appliances does not necessarily rely on smart meter roll-out, although a means of communicating with appliances is required. In the ACCESS project, for example, this is achieved via home broadband connection and Wi-Fi connectivity of smart appliances and thermostats. For some commercial models envisaged above, half-hourly metering may be required to enable revenue sharing between generators and demand managed customers, e.g. to enable time-varying tariffs. In addition to the communications with the homes, an inter-tripping arrangement is required between a monitoring point on the transmission system, i.e. at the constrained point, and a breaker that can trip out the generator should the constraint be breached.

Commercial / Regulatory	**Incentives to match local supply and demand.**	As well as enabling greater renewable utilisation, the local matching of generation and demand can assist supplier balancing, and reduce network costs and line losses. These benefits can be passed on by suppliers to consumers. Grid balancing is managed at the national system level; there is no general mechanism to encourage the supply of a customer on the same network circuit rather than one on the other side of the country. SETS and other demand matching schemes may comprise Local Balancing Zones, and many projects are looking at retaining generation value locally of this, such as Energy Local.
	Use of existing network for local supply.	In general, there is no means by which renewable generators can guarantee that their generation will be used preferentially by local demand, despite the savings above. As such, parallel private networks are being constructed in some areas, though obtaining planning permission can be difficult. Virtual private wire may allow small portions of existing grids to be used to match local demand and generation.
Technical	**DNO C&C infrastructure**	DNO monitoring infrastructure is, in general, insufficient to accurately price the services provided by aggregators in reducing net flow on constrained circuits.
Commercial/ Technical	**Provision of Ancillary Services**	Managed demand might provide further ancillary services, creating additional value. Services would need to be compatible with management of the transmission constraint (which would have priority call on available demand).
Technical	**Communication protocols and wireless range**	Any control platform is likely to communicate over the internet, most likely with a unit that interfaces with a user's wireless router. This may represent a problem with e.g. immersion tanks in the garage, or hot water tanks in the roof. A signal booster could resolve this problem at a one-off-cost of around £30.

3.8 Case 7: Energy-from-Waste to Electricity and Biogas

3.8.1 Case Introduction

Energy from waste (EfW) could contribute increasingly to the primary resources within the energy system.

Anaerobic Digestion (AD) plants have tended to produce renewable electricity and heat in CHP mode; due to current policy drivers, however it has become increasingly common for AD plants to produce renewable biomethane which is then injected into the gas grid. An alternative means of producing renewable gas is thermal gasification of biogenic waste which can then be post-processed to pipeline quality gas.

The diagnostic question in this Case Study is whether in the future, such systems could benefit from flexing their production between biomethane and electricity in response to volatile price signals, considering the additional capital and fixed operational cost required to enable them to operate in a multi vector configuration.

3.8.2 Scenario Definition

To assess the option value of EfW systems flexing their output in response to price signals, two different EfW systems are envisaged in this Case Study, in both single vector and multi vector configuration.

The analysis focuses on 2050, as an illustrative snapshot future year.

The broader energy system, comprising:

- supply mix,
- demand levels, and
- prices

are based on projections for the same year and is consistent with ESME Scenario 3 (High Wind), which represents a world of high renewables penetration and was generated for Case Studies 3 - 6 (see Appendix 9 for further information). The electrical and gas price time series are derived using the ESME2PLEXOS tool from the ESME Scenario energy system input assumptions; giving a 2050 hourly electricity price profile which encodes the average electricity price and its variability, as well as a gas shadow price in 2050 which is used as a proxy for the retail price.

Single and Multi Vector Configurations

Two EfW systems are studied, and described diagrammatically in the figure below:

a. Anaerobic Digestion (AD)
b. Thermal gasification of biogenic waste

In single vector configuration, the system is built with a single delivery system – either to generate electricity through a CHP plant, or to inject methane into the gas grid (we consider both potential single vector configurations as, in assessing multi vector value, we must demonstrate benefit over either single vector configuration alone). We also assume the underlying (single vector) EfW facility is already commissioned; as in Case Study 2 the analysis does not assess the overall project economics, but only the additional net costs and benefits of a multi vector operation.

In multi vector configuration, plants can flex their output in response to price signals as follows:

a. AD plant: Produces biogas which can be burned in a biogas CHP to produce electricity and heat. Alternatively, it can be cleaned-up and upgraded (to make the biomethane of grid quality), and subsequently injected into a grid-entry unit

b. Waste gasification plant: Produces syngas which is then post-processed (contaminants removed and CO_2 captured), into bioSNG that can substitute natural gas (fungible natural gas). BioSNG can either be burned in a standard natural gas CHP, or further processed to make it acceptable for grid injection. CO_2 capture is a necessary step in converting syngas to bioSNG for grid injection and is heat-integrated in the plant; methanation is an exothermic reaction, heat from this process provides can be used in efficient CO_2 desorption units.

Syngas can also be burnt in a modified CHP before CO_2 capture, but fewer such engines are available and they are typically de-rated to operate safely on this gas, leading to lower conversion efficiency and higher capital cost[101]. For this reason, this study envisages that plant CHP gas offtake occurs after the CO_2 capture step, which is therefore common to both gas injection and CHP mode.

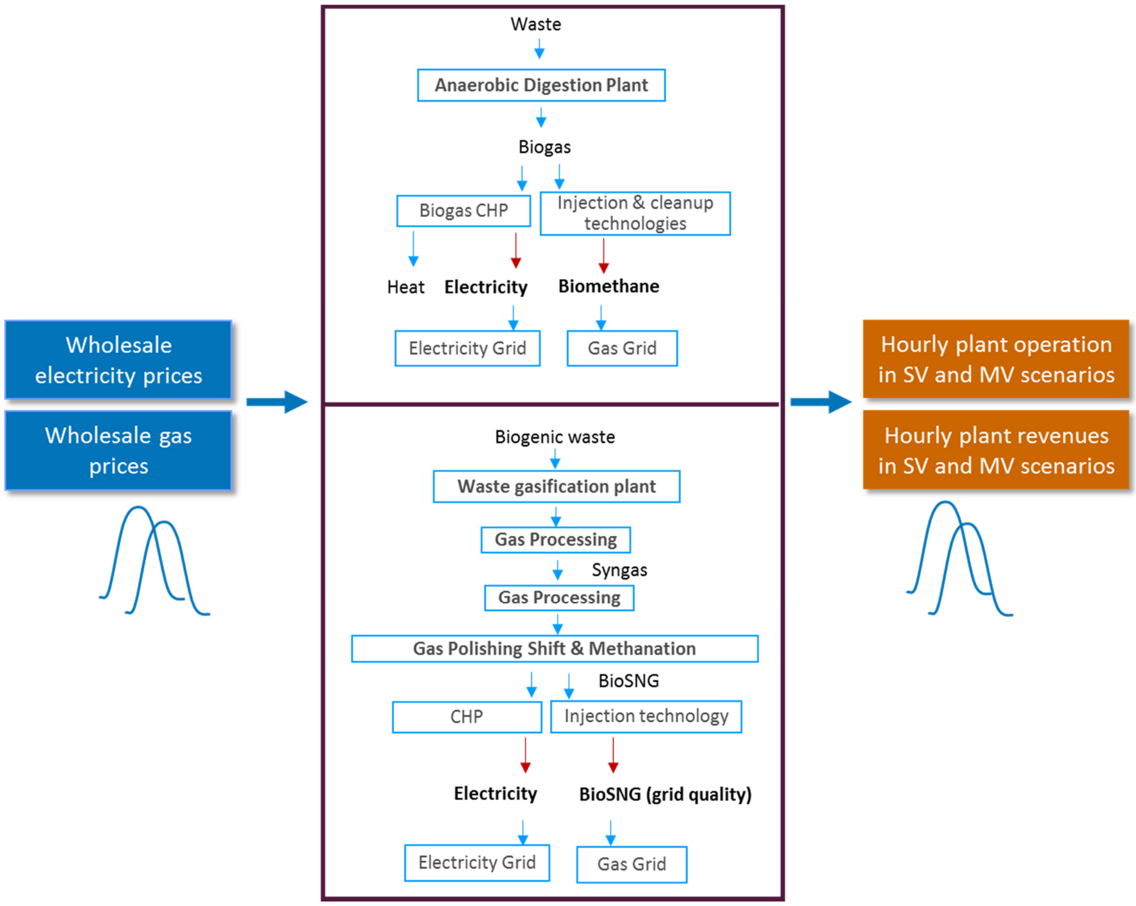


Figure 64- EfW multi vector configuration

Depending on which route is chosen as the single vector, each plant (AD/waste gasification) will need to be equipped with the technology required to operate in a multi vector mode; investing in this technology allows the system to respond to relative electricity and gas price signals - capturing gas injection revenues when this is more profitable than generating electricity, and vice versa.

It is worth noting that a single-vector gas injection plant would need to have access to some form of heat at high temperatures for the conversion of waste to gas, which would come at a cost. That heat demand could be offset by the heat produced by a CHP plant added in a multi-vector configuration, bringing some further value to the system. However, the value of the heat produced from the CHP plant has been ignored for simplicity in this study.

[101] Information obtained from Progressive Energy on Waste Gasification plants

3.8.3 Overview of methodology and analytical tools

The ability to export to the gas grid represents the option for the operator of the EfW facility to sell at a gas price or at an electricity price; this option will have value where price volatility in the electricity and gas markets is high, and where there is low correlation between them.

The Case Study analysis will quantify this option value and compare it to the additional infrastructure costs.

The required infrastructure comprises:

- processing and injection technology when the single vector counterfactual is assumed to be the CHP operation
- a CHP plant for when the single vector counterfactual is the injection of renewable gas into the grid (biomethane/bioSNG)

This approach builds on the electricity and gas price time series used in previous Case Studies by adding a probabilistic element, which allows us to determine the extrinsic option value[102].

To illustrate this, consider two price series as shown in the following figure.

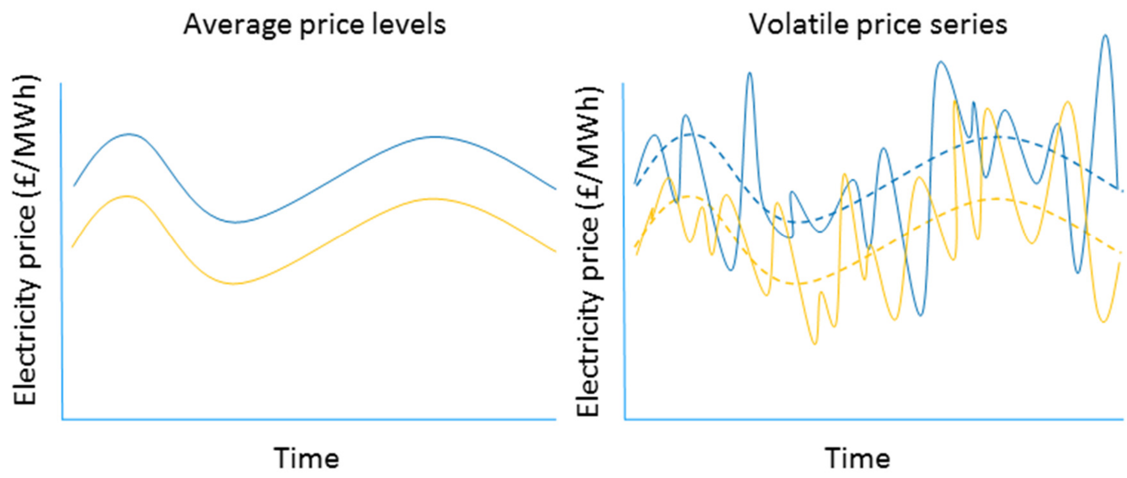


Figure 65-Pair of volatile price series

The left-hand graph shows rolling average prices; there is a constant difference between them, and an option that pays out when the yellow price exceeds the blue price would have no intrinsic value. The right-hand graph shows the spot prices; at times the yellow price exceeds the blue price, leading to a pay-out. Where prices move in the opposite direction, there is no impact as the pay-out is zero; it is this that leads to extrinsic value.

Monte Carlo Model

Our approach to quantifying the potential extrinsic value is to use a standard stochastic method, taking the deterministic price profiles of power and gas and layering in variability - we use a Baringa tool to generate a statistically consistent time series of power and gas spot prices, calibrated to historic price dynamics.

[102] Extrinsic value is the additional value of an asset (or contract) that results from volatile price movements around an average level. This occurs where the impact on the asset pay-out is asymmetric (and hence the changes do not average out to zero) – movements in one direction increase pay-out, but in the other decrease it by a smaller amount or not at all.

This tool includes parameters representing the volatility, mean reversion and correlation between the price series, and takes as inputs a pair of hourly power and gas price time series exclusive of any renewable energy subsidy payments, an assumption on their correlation; and outputs multiple simulations of price series pairs.

We generate 100 probabilistic projections, consisting of a pair of electricity and gas time series, for a given correlation value between the two. These pairs of price series simulations are unique, but statistically respect the properties indicated by the correlation parameter; for each hour, the mean value across all simulated prices matches the corresponding value in the initial deterministic price series.

The model then determines the optimal multi vector hourly dispatch decision for each series of price pairs, based on the revenues given by the efficiency-adjusted hourly power and gas prices for the CHP and gas-injection routes.

In each simulation, the benefit that the transition to multi vector operation represents is given by calculating total yearly revenues and comparing these to the corresponding revenues in the single vector case; the result is a set of 100 non-negative values representing the multi vector benefit for each simulation, which is used to generate a probability distribution of the multi vector benefit across all simulations, from which we determine the expected value. This is then compared to the annuitized investment and O&M costs of the required multi vector add-on technology.

In the Base Case scenario in this analysis, the deterministic hourly power price series used as a starting point for the generation of stochastic samples is the one corresponding to ESME Scenario 3 (High Wind) for 2050, generated using the ESME2PLEXOS tool (presented in previous sections, see Appendix 9.1.3 for more information). There is therefore an inherent volatility in the deterministic price series, which reflects the hourly dispatch of the electricity market under that 2050 ESME energy system scenario in which exogenous variable wind load factor hourly profiles have been used - as opposed to fixed average load factors (which lead to further hourly volatility in the electricity price signal - see Appendix 9 for further details). We anticipate that this will be the primary driver of volatility.

When generating the stochastic prices, some further randomness is added onto the signal, based on historical volatility and mean reversion of power prices. Despite being calibrated to historical values, this additional randomness (over and above the underlying fundamental variations described above) is assumed not to have particular drivers for change in the future. This is because the main source of volatility in the power price profile is closely related to the mechanism of price formation based on SRMC of plants and the real-time matching of demand and supply, which is not expected to change in the future.

The deterministic hourly gas price series is based on the gas shadow price for the same scenario (see Appendix 9) in 2050, to which variability has been added based on volatility and mean reversion historically observed in the day-ahead gas price; clearly future gas price dynamics may change, but unlike electricity there is no clear trend to justify higher or lower levels.

Price Correlation

The correlation between power and gas prices, has been assumed to be 15% in the Base case scenario, based on average historical observations. UK market fundamentals in 2050 suggest this correlation may be lower in the future - prices are set less frequently by gas-fired plant and therefore we have investigated the sensitivity of the results on this parameter.

Plant Capacity

The model assumes constant 20MW infeed of waste, which can be converted to either electricity and heat or renewable gas for injection into the gas grid at the respective efficiencies.

3.8.4 Input Assumptions

The key components in this analysis are:

- the efficiency losses in each of the conversions routes for each type of plant (AD/gasification)
- the capital and fixed costs associated with the transition from each single vector scenario to the multi vector configuration that will be compared against the multi vector benefit.

Relevant assumptions are summarised in the table below;

- efficiency loss factors are based on values defined in ESME v4.1 for AD CHP (waste-to-electricity and heat), AD gas (waste to gas), and Waste Gasification (waste to electricity and heat) plant. The overall conversion efficiency for a waste gasification plant from waste to bio-methane was taken from conversations with Progressive Energy[103] (see Appendix 7 for more information).
- Capital and fixed costs for CHP only plants were based on the assumptions on macro-CHP plants available in ESME V4.1.
- The capital cost for grid injection units (otherwise referred to as Grid Entry Units/Network Entry Facility) was based on information provided by Progressive Energy and CNG services for waste gasification and AD plants respectively.

The Grid Entry Unit includes

- a propane injection facility which improves the biomethane/bioSNG calorific value so that it meets grid quality standards,
- the required Remote Telemetry Unit (RTU) and network-owned remote operate valve.

According to Progressive Energy, the cost for the Grid Entry Unit (GEU) is dominated by Ofgem-mandated analysers, quality assurance, injection pressure regulation and other control and monitoring plant; it is not therefore expected to differ significantly between different types of plants, or to be materially affected by the size of the plant. Therefore, in this study, it has been assumed that the cost of a GEU unit, i.e., the cost for converting a single-vector existing CHP plant to a multi-vector system, is fixed and does not scale up with the size of the plant. On the other hand, the cost of adding a CHP unit varies by size. This indicates that when comparing the benefits of converting the two different single-vector systems into multi-vector, the assumption made on the initial plant capacity (MW) will be key.

An additional cost has been added to both plant categories for interconnecting pipes, ducting and control systems following conversations with CNG services, the costs for the gas network export pipeline have been ignored.

Fixed costs of £60k have been assumed for flaring, based on information provided by CNG services, this is also assumed not to be affected by the capacity of the plant. In the absence of specific information, the same value is used for the fixed cost for injecting gas from waste gasifiers into the gas grid.

The total costs have been annualised based on a plant lifetime and discount rate taken from ESME v4.1 data for waste gasification and AD plants.

[103]Taken from conversation with Progressive Energy.

Table 92- Technical and economic data input assumptions

Parameter	Anaerobic Digestion	Gasification
Plant capacity on per input basis (MW)	20	20
Plant availability (%)	100	100
Efficiency: waste to electricity (%)[104]	16	31
Efficiency: waste to grid injection biomethane/BioSNG (%)	26	65
Single Vector route 1: CHP mode		
capex of additional technologies: Upgrade & injection plants (£k)	700	700
Fixed costs of additional technologies: Upgrade & injection plants (£/year)	60	60
Economic lifetime (years)	20	20
Discount rate (%)	8	8
Single Vector route 2: Gas grid injection		
Capex of additional technologies: CHP plant (£/kWe)	490	490
Fixed costs of additional technologies: CHP plant (£/kWe/year)	27	27
Economic lifetime (years)	20	20
Discount rate (%)	8	8

The efficiency assumptions are taken from ETI's bioenergy programme data. We note that the waste to gas and waste to power values, and their ratios, are different for the two plant types, reflecting differences in the technologies, the energy costs of the clean-up processes, and typical feedstocks.

3.8.5 Case Study Analysis

Key outputs of the model, using the methodology described in the previous section, are illustrated for the Base Case scenario in the following section; the probabilistic analysis carried out in this Case Study uses 100 stochastic simulations for electricity and gas prices which are shown in the following two figures. As discussed above, there is an inherent volatility in the electricity price reflecting the electricity system in 2050 and exogenous historical hourly volatility of wind energy output.

The electricity price signal has high mean reversion because the price formation is closely linked to the plants' SRMC, and supply and demand matching are possible in close to real-time. Therefore, as seen in the graph below, the signal tends to revert to the underlying deterministic pathway quickly.

On the other hand, the gas price signal shows a lower tendency to revert to its mean value, and many price pathways diverge for significant periods from the underlying mean, which reflects:

1. a more diffuse set of price drivers for gas, including influences across a much broader geographic spread,
2. the strong influence of commercial and contractual arrangements,
3. stronger influence of varying longer term price views given the availability of gas storage.

[104] Efficiency figures quoted are based on MWh main output/MWh input waste ratio

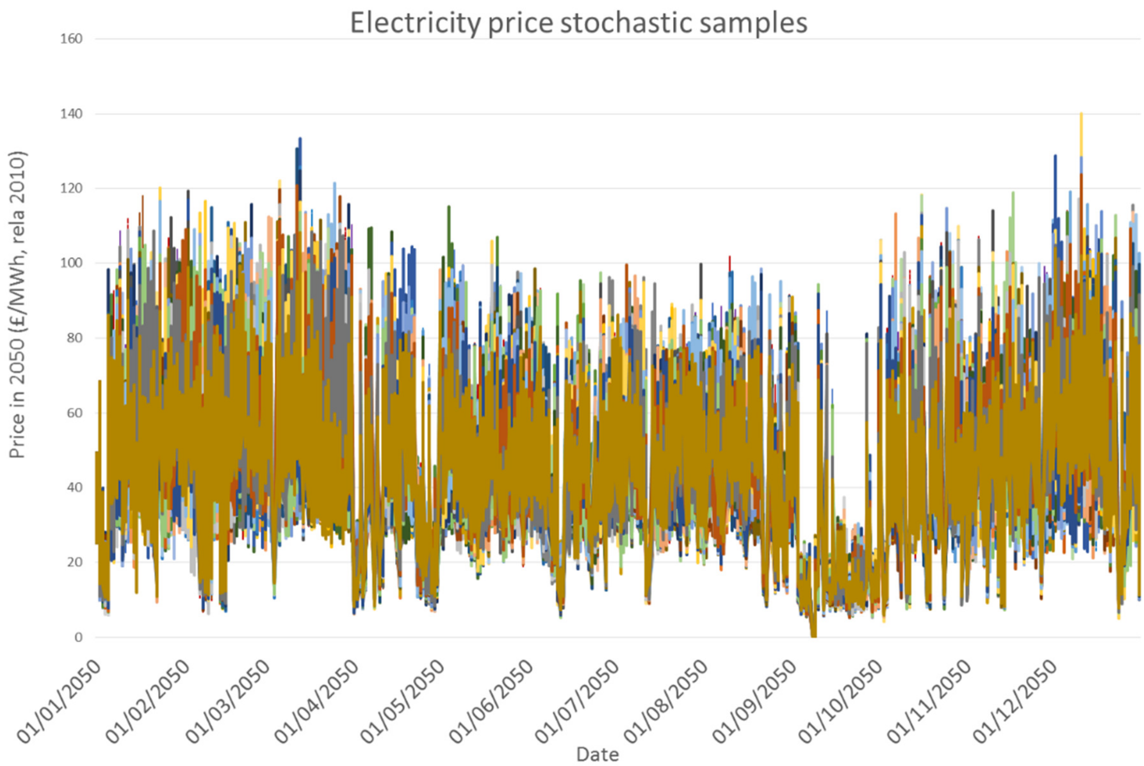


Figure 66- Base case probabilistic samples for electricity prices in 2050 (real 2010)

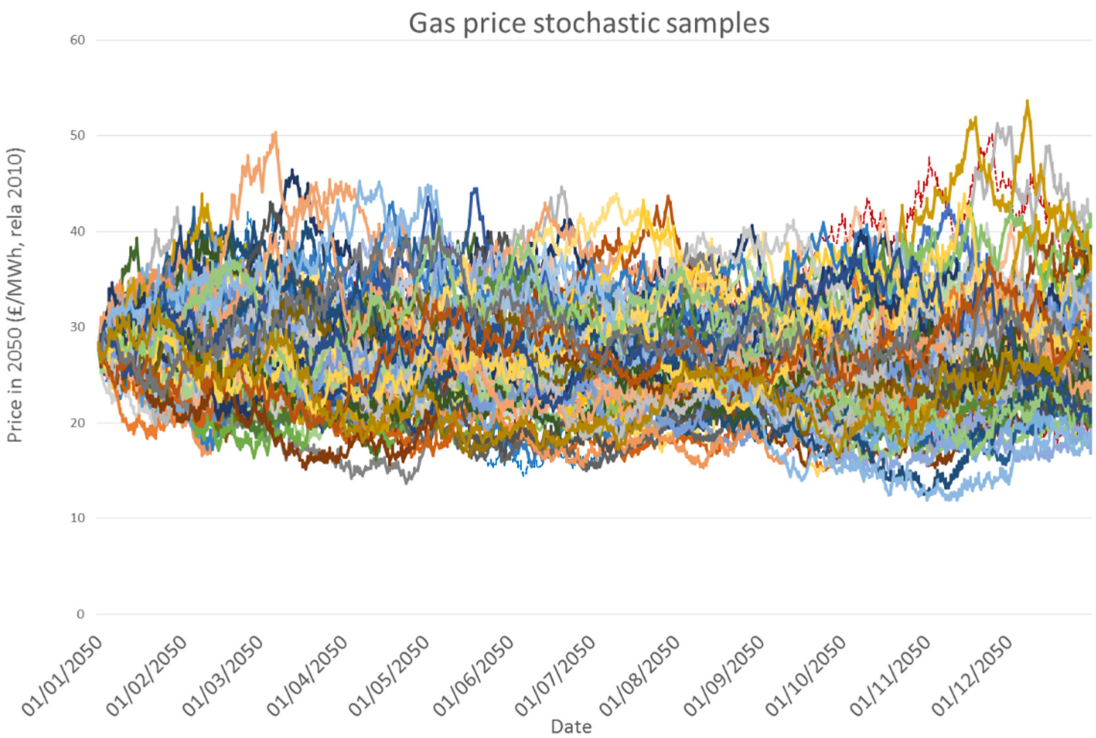


Figure 67-Base Case probabilistic samples for gas prices in 2050 (real 2010)

The graph below shows the average over the above probabilistic scenarios generated for electricity and gas; the correlation between the two signals is 15% in the Base Case Scenario, as described above. The model uses a Monte Carlo approach, calculating

- the plant revenues in each of the two single vector scenarios (CHP operation or gas injection) and
- optimal dispatch of the multi vector scenario in which the plant can choose the conversion route that yields the highest revenues, responding to the hourly price signals.

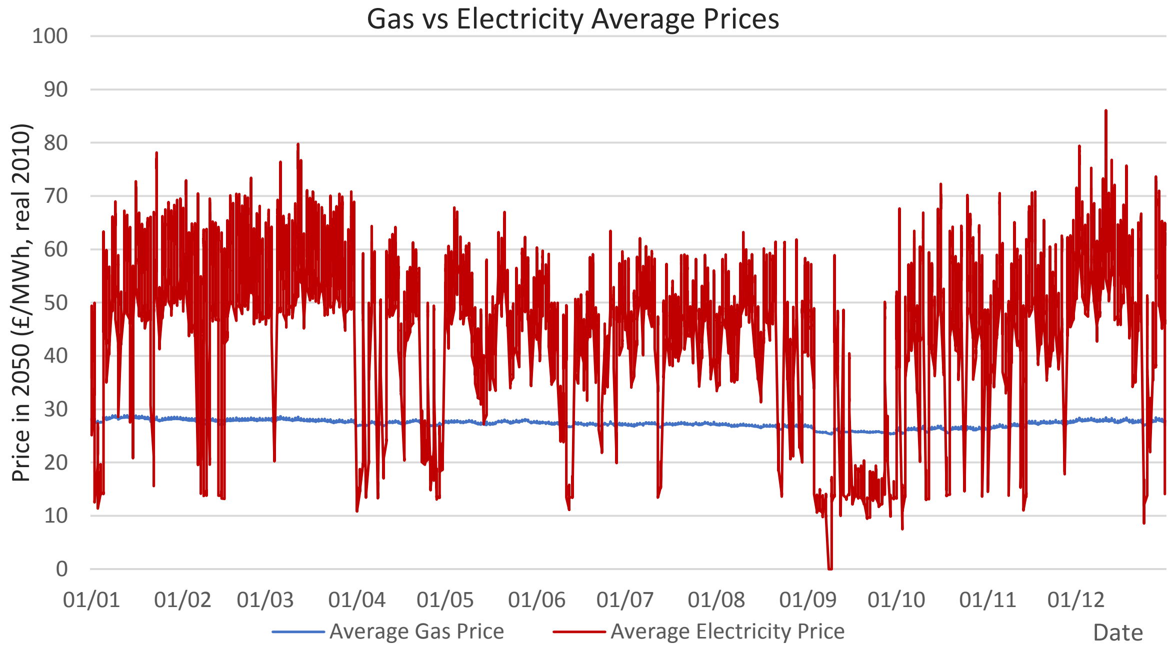


Figure 68-Base Case average electricity vs gas prices in 2050 (real 2010)

Anaerobic Digestion Plant

The following figure illustrates the percentage of time in which a multi vector AD plant operates in a CHP and a gas injection mode in the Base Case, across all 100 simulations.

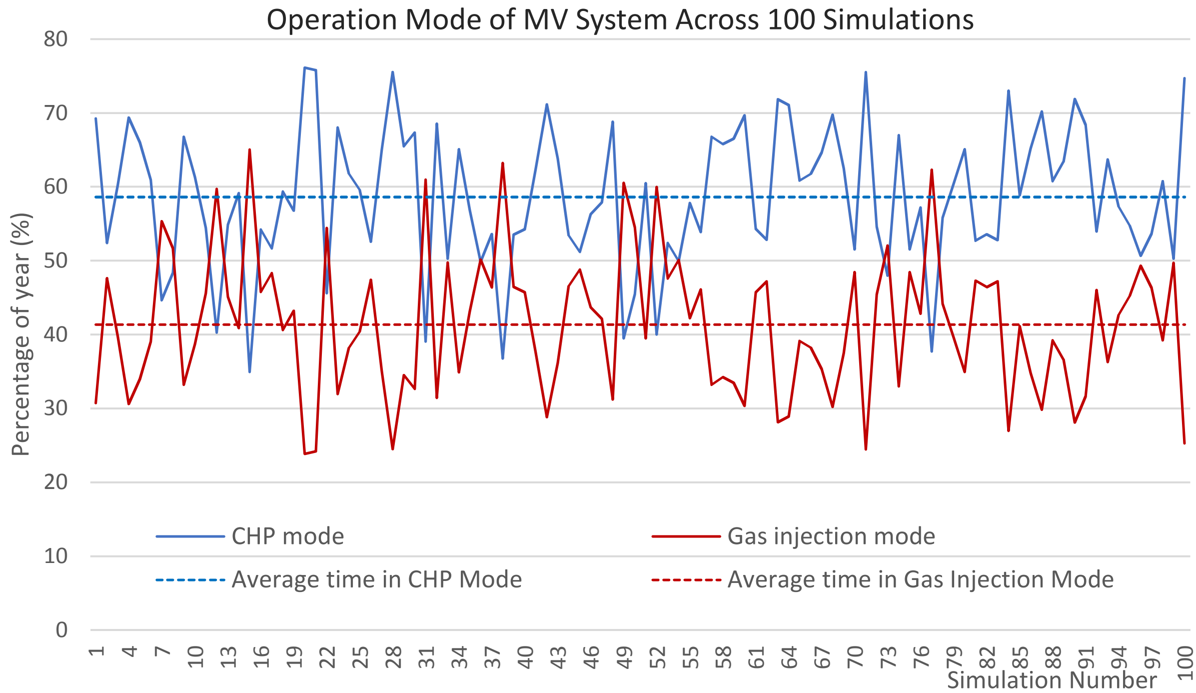


Figure 69-Multi vector plant operation across 100 simulations

Most of the time, the plant operates in CHP mode; since efficiency adjusted electricity prices are on average higher than gas prices. However, the plant spends a significant amount of time in gas injection mode, showing that there is value in enabling the plant to respond to system prices.

For the given prices and original plant capacity, there is net benefit from both adding gas injection equipment to an existing CHP plant and adding a CHP plant onto an existing gas injection plant. Despite the latter option having greater revenue benefit, the net benefit for the former plant is higher due to the lower capital and fixed costs of installing the additional plant (gas injection unit). It should be highlighted, that this depends on the choice of plant capacity, since the cost of the gas injection unit is assumed fixed while the cost of CHP scales with capacity.

The key results for an AD plant in the Base Case scenario using the price signals illustrated above are summarised in the following table; these indicate that a single vector CHP plant (SV-1) can benefit from installing a gas injection unit as its revenues are increased by 14% and the profit margin of that additional revenue is 26% (£46k, taking out the additional capital and operational costs of the new equipment). Adding a CHP plant to an existing gas injection plant (SV2), increases its revenues by 21%. However, due to the higher costs of installing a CHP unit at this scale, the profit margin of the additional revenue is only 2% (£6k).

Table 93- Base Case Results for AD Plant

	Base Scenario- AD plant operation			
	SV 1 CHP mode	MV vs SV 1	SV 2 Gas injection mode	MV vs SV 2
Deterministic Electricity Prices	ESME2PLEXOS prices as per ESME Scenario 3 (£47/MWh average)			
Deterministic Gas Prices	Shadow price ESME Scenario 3 shaped with historical volatility (£28/MWh average)			
Electricity vs gas prices correlation	15%			
CHP mode (%)	100	59	-	59
Gas injection mode (%)	-	41	100	41
Mean value of revenues from gas/electricity sales (£k)	1,323	1,505	1,244	1,505
Mean value of benefit (£k)	**-**	**180**	**-**	**259**
Annualised capex and Fixed Opex of additional plant (£k)	-	134	-	253
Mean value of net benefit (net of additional MV costs) (£k)	-	46	-	6

Upgrading single vector injection and CHP AD plants to multi vector supply is, on average, marginally beneficial to both. If there is no market for the heat produced (i.e. a heat price of zero), the benefit in going from CHP to multi vector operation are greater than those of adding CHP to a gas injection plant, reflecting the greater value of green gas.

Sensitivity Analysis

The sensitivity of the results to the correlation between electricity and gas prices is illustrated in the following two tables.

Power and Gas Price Correlation

When correlation is reduced from 15% to 6%[105], the multi vector benefit for both cases increases, with both systems having a higher increase in revenues and profit margin of those revenues; this is expected, since the option value increases for signals that are less correlated - there are more times when the gas price exceeds the electricity price and vice-versa. While the average revenues in each single vector scenario remain the same, the multi vector system higher option value increases; its revenues and net benefit are therefore higher.

Table 94- Sensitivity Results for Lower Price Correlation Levels

	Sensitivity 1-AD plant operation			
	SV 1 CHP mode	MV vs SV 1	SV 2 Gas injection mode	MV vs SV 2
Deterministic Electricity Prices	ESME2PLEXOS prices as per ESME Scenario 3 (£47/MWh average)			
Deterministic Gas Prices	Shadow price ESME Scenario 3 shaped with historical volatility (£28/MWh average)			
Electricity vs gas prices correlation	6%			
CHP mode (%)	100	59	-	59
Gas injection mode (%)	-	41	100	41
Mean value of revenues from gas/electricity sales (£k)	1,323	1,510	1,244	1,510
Mean value of benefit (£k)	-	186	-	264
Annualised capex and Fixed Opex of additional plant (£k)	-	134	-	253
Mean value of net benefit (net of additional MV costs) (£k)	-	52	-	11

Conversely in Sensitivity 2 - where gas prices follow the movement of electricity prices at a correlation of 94% - the multi vector option value significantly reduces; despite both single-vector plants seeing an increase in revenues from multi-vector operation, neither sees a net cost benefit due to relatively high capital and operational costs of the new upgrade equipment.

105 The correlation values tested in the sensitivity analysis are indicative examples of correlation levels; the specific numbers were determined by the model architecture.

Table 95- Sensitivity Results for Higher Price Correlation Levels

	Sensitivity 2-AD plant operation			
	SV 1 CHP mode	MV vs SV 1	SV 2 Gas injection mode	MV vs SV 2
Deterministic Electricity Prices	ESME2PLEXOS prices as per ESME Scenario 3 (£47/MWh average)			
Deterministic Gas Prices	Shadow price ESME Scenario 3 shaped with historical volatility (£28/MWh average)			
Electricity vs gas prices correlation	94%			
CHP mode (%)	100	65	-	65
Gas injection mode (%)	-	34	100	34
Mean value of revenues from gas/electricity sales (£k)	1,323	1,381	1,244	1,381
Mean value of benefit (£k)	-	59	-	136
Annualised capex and Fixed Opex of additional plant (£k)	-	134	-	253
Mean value of net benefit (net of additional MV costs) (£k)	-	-75	-	-117

Multi vector benefit – the option value – rises as electricity and gas prices become uncoupled, and falls (to below zero) when they are more tightly linked.

Increased Gas Price

To investigate the impact of average prices on the Base Case scenario results, the average gas price was increased by £20/MWh, leading to an average value of £47/MWh (approximately equal to the electricity price); the results for this analysis are shown in the following table.

Table 96- Sensitivity Results from Increasing Average Gas Prices

	Sensitivity 3-AD plant operation			
	SV 1 CHP mode	MV vs SV 1	SV 2 Gas injection mode	MV vs SV 2
Deterministic Electricity Prices	ESME2PLEXOS prices as per ESME Scenario 3 (£47/MWh average)			
Deterministic Gas Prices	Base Case prices (£28/MWh average + £19/MWh ≈ £47/MWh)			
Electricity vs gas prices correlation	15%			
CHP mode (%)	100	6	-	6
Gas injection mode (%)	-	93	100	93
Mean value of revenues from gas/electricity sales (£k)	1,323	2,124	2,110	2,124
Mean value of benefit (£k)	-	805	-	15
Annualised capex and Fixed Opex additional plant (£k)		134	-	253
Mean value of net benefit (net of additional MV costs) (£k)	-	671	-	-237

Under gas prices comparable to electricity costs, multi vector plants operate mainly in gas injection mode. Under these prices, there is no net benefit for a gas injecting AD plant upgrading to multi vector.

Under these gas prices, the cost of installing a CHP engine is more expensive than the value of the electrical export revenue, due to the low load factors (6%). Conversely, a (20MW) AD CHP plant increases its revenues by 61% through multi vector upgrade, which leads to a positive net benefit after the deduction of capital costs – 83% of extra revenue constitutes profit. On this basis, multi vector upgrade would be beneficial to AD CHP plants of around 4MW capacity at high gas prices.

As in the previous analysis, multi vector benefit increases at correlation between prices and gas lower than the 15% used in the base case, and reduces at higher correlation levels. In today's market, gas price is a primary driver of power price, due to the level of gas-fired generation; leading to a positive correlation between the two. However, market dynamics in 2050 could look very different; in a world where CCS is not supported, there will be very limited (unabated) gas generation, removing this fundamental link between prices, and high levels of renewable generation will drive power price volatility. Alternatively, where there is substantial CCS gas-fired generation capacity, some correlation between gas and power prices will remain.

The future use of gas (including natural gas and biogas) for power generation is hugely uncertain, and depends on (among other things), the deployment of CCS and the development of biogas. On the demand side, it is possible that gas may play a more peak and flexibility role (for example, in hybrid heating systems) which could also drive significant price volatility.

Overall then:

- We expect low correlation between gas and power prices
- There are drivers for higher power price volatility

in the latter stages of a decarbonisation pathway.

Heat Price

CHP heat has not been considered in the base case analysis, on the basis that EfW plants are typically located far from centres of domestic thermal demand; where CHP heat can be used, e.g. supplying industrial heating demand, the revenues of the CHP plant increase.

To get a high-level view of how the results above change under a non-zero heat price, we modelled a range of heat price scenarios, taking the heat price as a fraction of the gas price – ranging from 10% to 100% – on the basis that heat would otherwise be produced using gas boilers. For a 20MW AD plant, we found that as the heat price approaches the gas price, multi vector benefit for an existing CHP plant falls to the point that it is not economically sensible to invest in gas grid injection technology (net multi-vector benefit becomes negative). Conversely, we found that AD plants operating in gas injection mode see an increasing multi vector benefit as heat price increases.

At very large AD CHP plants there may be some benefit in upgrade for grid injection even under non-zero heat prices, since the cost of injection technology does not vary materially with size, whereas multi vector revenues increase as a function of plant capacity.

Overall, multi vector benefit (net of the investment costs) depends on

- the type and size of existing single-vector system
- whether generated heat can be used, and at what price it is valued.

Where CHP heat can be sold, e.g. to supply to a heat network or offset of internal demand supplied by gas boilers, gas injecting AD plants of most sizes would benefit from multi vector upgrade.

Waste Gasification Plant

The following figure illustrates the percentage of time in which a multi vector waste gasification plant operates in CHP and gas injection modes in the Base Case, across all 100 simulations.

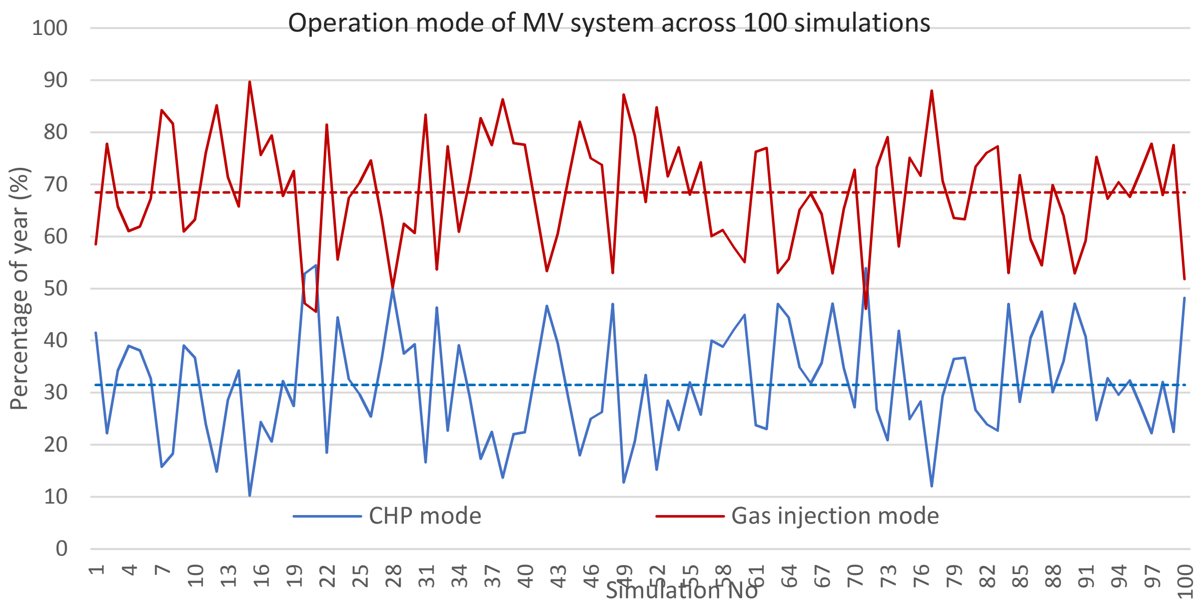


Figure 70-Multi vector plant operation across 100 simulations in Base Case

Most of the time, the plant operates in a gas injection mode; despite electricity prices being higher on average than gas prices, the conversion efficiency from waste to BioSNG is significantly higher (see Table 92).

Key results for the 20MW waste gasification plant are summarised in the following table, using the Base Case fuel price date; the CHP plant (SV-1) sees significant net benefit in upgrading to multi vector operation, increasing its revenues by 29%, with 82% of those additional revenues representing profit. On this basis, CHP gasification plants of 4MW in capacity and above might upgrade to grid injection. Conversely, gas injection plant does not see sufficient benefit in installing a CHP engine, which comes at a significant cost.

Table 97- Base Case Results for Waste Gasification Plant

	Base Scenario- Waste gasification			
	SV 1 CHP mode	MV vs SV 1	SV 2 Gas injection mode	MV vs SV 2
Deterministic Electricity Prices	ESME2PLEXOS prices as per ESME Scenario 3 (£47/MWh average)			
Deterministic Gas Prices	Shadow price ESME Scenario 3 shaped with historical volatility (£28/MWh average)			
Electricity vs gas prices correlation	15%			
CHP mode (%)	100	31	-	31
Gas injection mode (%)	-	68	100	68
Mean value of revenues from gas/electricity sales (£k)	2,564	3,316	3,112	3,316
Mean value of benefit (£k)	-	761	-	208
Annualised capex and Fixed Opex of additional plant (£k)	-	134	-	490
Mean value of net benefit (net of additional MV costs) (£k)	-	627		-282

Gasification plants with CHP export (power only) justify investment in upgrade to multi vector operation; injection plants do not (at zero heat price).

We note that multi vector operation is optimal for AD but not gasification plant, as power to gas generation ratios are higher for the former than the latter.

Sensitivities

Increased Electrical Prices

The tipping point, at which gas injecting waste gasification plant sees a positive return from CHP installation, occurs at electricity prices increase of £59/MWh, 25% above the ESME average value; results at these prices are shown in the following table. These revenue levels correspond also to a positive heat sale price of 12% of the power price, around £6/MWh, or 20% of the gas cost[106]. As CHP engine costs scale with plant capacity, these findings are not very sensitive to gasification plant size, though some cost components of CHP upgrade will be fixed.

Table 98-Sensitivity Results from Increasing Average Electricity Prices

	Sensitivity 1-Waste gasification			
	SV 1 CHP mode	MV vs SV 1	SV 2 Gas injection mode	MV vs SV 2
Deterministic Electricity Prices	ESME2PLEXOS prices as per ESME Scenario 3 £47/MWh average + £12/MWh = £59/MWh			
Deterministic Gas Prices	Base Case prices (£28/MWh average)			
Electricity vs gas prices correlation	15%			
CHP mode (%)	100	56	-	56
Gas injection mode (%)	-	43	100	43
Mean value of revenues from gas/electricity sales (£k)	3,216	3,609	3,112	3,609
Mean value of benefit (£k)	-	393	-	495
Annualised capex and Fixed Opex of additional plant (£k)	-	134	-	490
Mean value of net benefit (net of additional MV costs) (£k)	-	259	-	5

At 25% higher electricity prices, adding multi vector capability creates a benefit for each of the initial system configurations.

Where a gasification plant can supply both heat and power at plausible prices, they increase their potential revenues above those available through gas injection. As such, ACT and ATT plants may play some role in the supply of heat networks.

[106] Assuming CHP thermal efficiency is no worse than twice the electric efficiency.

Power and Gas Price Correlation

The impact of lower power and gas price correlation levels on the results is shown below; the correlation is reduced to 6% from 15%, as in the previous AD plant case. As expected, lower correlation between the price signals leads to increases in both multi vector upgrade options, though the increase is insufficient to justify investing in CHP at existing waste gasification gas injection plants.

Table 99- Sensitivity Results from Lowering Correlation

	Sensitivity 2-Waste gasification			
	SV 1 CHP mode	MV vs SV 1	SV 2 Gas injection mode	MV vs SV 2
Deterministic Electricity Prices	ESME2PLEXOS prices as per ESME Scenario 3 (£47/MWh average)			
Deterministic Gas Prices	Base Case prices (£28/MWh average)			
Electricity vs gas prices correlation	6%			
CHP mode (%)	100	32	-	32
Gas injection mode (%)	-	67	100	67
Mean value of revenues from gas/electricity sales (£k)	2,564	3,326	3,112	3,326
Mean value of benefit (£k)	-	772	-	217
Annualised capex and Fixed Opex of additional plant (£k)	-	134	-	490
Mean value of net benefit (net of additional MV costs) (£k)	-	638	-	-272

Grid injection is almost always preferable for gasification plants at the scale used in this analysis (20MW input); uncoupling electrical and gas prices makes no material difference to these findings.

3.8.6 Key Findings

Our analysis evaluates the benefit to an existing single vector plant - operating either in CHP or in gas injection mode – in investing in additional technology that enables it to switch between electricity and gas production in response to real-time price signals. Therefore, the focus of our economic analysis is the option value of multi vector operation compared to the investment costs associated with single to multi vector transition. The operational costs associated with mode-switching and the variable operational costs of the new investment are ignored for simplicity, on the assumption that capital and fixed costs would most materially affect the results. Correlation between gas and electricity prices is expected to be low in 2050, and volatility high.

Our analysis suggests there may be price levels that justify the extension of an existing single vector facility to incorporate the option to flex between electricity and gas outputs. However, there are only relatively narrow price bands which justify building this option at the outset – it is more likely that one route will be more economic initially, but that over time relative prices may shift to justify the incremental addition of the alternative route.

The case for investment in a CHP plant is highly sensitive to the sale price of heat, there may not be local heat in proximity to all gasification, and particularly AD plant – most heat generated through AD CHP is vented. Under heat prices that are only a small fraction of the gas price however, gasification and AD CHP facilities outperform gasification and (at slightly higher heat prices) gasification plant.

Our financial analysis considers only capital and annual fixed components of this investment; the capital and operational costs of the original single vector plant are not considered. Therefore, further analysis would be required to evaluate the business case of building a brand-new plant. As the effect of gas on electricity prices may vary substantially over time – both on short term volatility and longer term, more structural shifts – there may be value in minimising barriers to allowing biogas/biomethane projects to supply both the electricity and gas vectors.

3.8.7 Operational and Engineering Implications

A number of the barriers to operating AD and gasification plants in the multi-vector configurations described in this case study are discussed in the table below.

	Issue	Impact and Solution / Mitigation
Regulatory	**Planning restrictions on AD and waste gasification plants likely to result in plant locations that are far from domestic heat demand.**	Local planning and waste disposal authorities typically designate land for waste treatment facilities that is distant from town centres or residential areas, due to concerns regarding odours, vehicle movements for feedstock deliveries and visual amenity. As a consequence, energy from waste plants are often far from areas of high heat demand (unless, for example, the plant is located near an industrial estate). Failure to utilise the heat from EfW plants equipped with CHP significantly reduces overall plant efficiency. District heating systems may offer an opportunity to transport heat to areas of demand, provided the plant is located within an economic distance, given the cost of pipe infrastructure, from adequate demand centres.
Technical	**In the AD case, flexing between biogas CHP and gas grid injection requires intermittent operation of the biogas upgrading technology**	In the case that a biogas upgrading and injection unit is added to an existing biogas plant with CHP, the upgrading facility is only used at times of low electricity price (biomethane to grid is the preferred route for 65% of the time). This intermittent use of the upgrading facility may have implications for lifetime of components and there may also be response rate considerations when switching from electricity generation to gas grid injection or vice versa. There are several technologies commonly used for the upgrading of biogas to biomethane, including: • Water scrubber • Chemical scrubber • Pressure Swing Adsorption • Membrane (Cryogenic) A case study of one of these upgrading technologies – selective membrane separation – is found at the Poundbury biomethane to grid plant (the first commercial biomethane to grid plant in the UK). From a standstill start, the total time for biomethane to grid under normal operation is around 20 minutes, including bringing CO_2 and CH_4 content into the specified range and performing 3-4 gas spectrometry measurements before the grid injection begins. Injection of propane for CV control starts as soon as the biomethane reaches the required range; suggesting that the unit could be operated in a flexible way. Note that in the waste gasification case described in this case study, the syngas to bioSNG step is common to both the CHP and gas to grid pathways, so the upgrading unit can work continuously irrespective of the final product.

Commercial / Regulatory	**Minimum CV requirements for injection to the distribution network, leading to high propanation costs**	Biomethane and bioSNG will typically have a lower calorific value than natural gas in the local distribution zone (LDZ) to which they are connected. The flow-weighted average CV (FWACV) is the average CV of all gas inputs into the LDZ, and the maximum billable FWACV is capped at the CV of lowest source to the LDZ + 1 MJ/m^3. This cap results in a difference between the billable CV and the actual CV of gas in the LDZ – this unbilled energy is known as the 'shrinkage'. Shrinkage will be large where the low CV gas source is only a small fraction of the total gas supplied in the LDZ. To avoid large shrinkage costs, distributed gas facility operators are required to add propane to their gas before injection to ensure that the CV meets the local FWACV. Propanation costs can be prohibitively high, particularly for small-scale producers. For example, a 500 scmh[107] biogas plant could incur costs in the region of £150,000/year (or 0.3p/kWh of gas injected), assuming a CV of 37 against a FWACV of 39 MJ/m^3. We note that both biomethane from AD, and bioSNG from gasification will both have CVs of below that of natural gas, and require propanation under current injection regimes. Solutions to the issue of shrinkage and the associated high propanation costs for producers could include 'energy blending', whereby the biomethane / bioSNG producer injects gas at a point in the network with sufficiently high throughput that the impact of the lower CV gas on the FWACV of the blended gas downstream of the injection point is within acceptable limits; only when the CV target is not met by the blended gas is the producer required to add propane before injection. Clearly this solution is limited to injection points where there is sufficient flow in the network, given the injection rate, that the impact on FWACV is limited. A commercial solution to the problem would be to designate smaller charging zones within LDZs that have multiple gas sources, limiting the potential for shrinkage and reduced the propane requirement for producers injecting into the zone. This concept is being explored in National Grid's NIC project 'Future Billing Methodology'.
Commercial	**Exposure to wholesale electricity price variations**	Most small-scale electricity generating plant, particularly at the typical scale of AD plants but also large waste gasification plants, do not participate directly in the wholesale electricity market. More commonly these plants would be contracted to an electricity supply company and sell their electricity under a power purchase agreement (PPA) at a fixed tariff (with a share of embedded benefits). The costs associated with operating in the wholesale market to take advantage of short-term (intra-day) price variations have not been fully accounted for in the case study, which has considered only the main capital items required, e.g. the CHP engine, but the operational overheads associated with participating in the wholesale market are likely to be significant. Further, the expertise required for this level of engagement may not be common among operators of AD or waste gasification plants.

[107] Standard cubic meters per hour

<table>
<tr><td>Technical</td><td>Capacity constraints on the distribution network, leading to high connection costs to connect at a point with sufficient capacity</td><td>GDNOs limit the capacity offered to distributed injection facilities to the minimum demand downstream of the gas entry point. This can be a significant constraint where summer minimum demands are low, particularly for plants seeking connection to the intermediate or medium pressure (IP or MP) tiers of the gas network. Currently the most common means of accessing greater capacity is to pipe the gas to a point on the network where there is greater demand, however, this can be costly, depending on the location of the plant in relation to higher pressure tiers of the network. There are a number of alternative technical solutions that could be implemented to overcome network capacity constraints, including:
• Gas storage during times of low demand
• Smart management of network pressure
• In-grid compression of gas to higher tiers
• Interconnection of networks
Smart pressure management involves operating the network at reduced pressure during periods of low demand (e.g. summer), such that linepack storage is created within the network (i.e. the pressure is allowed to increase to accommodate injected gas). The network pressure can be controlled by automated gas flow regulators at intake points (i.e. where gas is input from the higher pressure tier), which react to signals from pressure monitoring devices that ensure that the pressure on the network does not deviate from an acceptable range. A number of trials of smart pressure management are underway on the GB gas grid (National Grid and Wales and West Utilities in Cambridgeshire and Bristol respectively). This is a low cost solution, but is limited in terms of the additional capacity created. In-grid compression, which involves compressing excess gas up to the higher pressure tier has potential to create greater capacity (depending on the demand experienced by the higher tier of the network), but requires new compressors to be fitted in the network, incurring significant cost.</td></tr>
<tr><td>Commercial / technical</td><td>High costs for grid entry units and long timescales for approvals</td><td>The costs of the grid entry unit (GEU) are currently significant and can undermine the business case for grid injection (particularly for low flow sites, where connection costs will be a larger fraction of overall costs). Furthermore, the timescales for design and approval processes can be protracted, which can increase the costs associated with connection (and are also relevant for securing the RHI at a particular tariff rate, as the RHI is currently set after plant commissioning). National Grid's CLoCC project is developing proposals for lower cost designs and more rapid approval processes for distributed producers seeking a connection to the national transmission system. For connection to the distribution system, a standard specification for GEUs has already been developed, although distributed producers report some variation between requirements of different GDNOs that lead to increased costs and inability to standardise. Further consultation between GDNOs and distributed producers is required to harmonise requirements and reduce connection costs and timescales.</td></tr>
</table>

Technical	**For CHP serving an existing heat demand, flexing between CHP and gas to grid may not be possible.**	Where an existing CHP system is providing heat to a nearby demand (or supplying heat to a district heating system), then the operator may not be able to switch between CHP and gas grid injection on short timescales – this for example may breach a heat supply contract. Under these circumstances, flexible operation will result in times when alternative plant will be required to meet the heat demand, which may result in additional costs being incurred by the operator (in the analysis presented here, a conservative assumption has been made that the heat from the CHP facility has no value).
Technical	**Onsite CHP will be less efficient overall than gas grid injection if there is no demand for the heat.**	For gasification plants that produce bio-SNG, which is fungible with natural gas, better overall system efficiency may be achieved by using the gas network to transport the gas to an efficient end-use (such as gas boilers or CCGT), rather than using the gas onsite for electricity generation with heat rejection.

4 Glossary and Acronyms

Term	Definition
ACT	Advanced Conversion Technologies
AD	Anaerobic digestion
ATT	Advanced Thermal Treatment
BAU	Business as Usual
BEV	Battery electric vehicle
CBA	Cost benefit analysis
CCC	Committee on Climate Change
CCGT	Closed Cycle Gas Turbine
CCS	Carbon capture and storage
CHP	Combined Heat and Power
CIBSE	Chartered Institution of Building Services Engineers
CO_2e	Greenhouse gas CO_2 equivalent
COP	Coefficient of Performance
DH	District heat
DHW	Domestic hot-water
DN	Distribution network
DNO	Distribution network operator
DSR/DSM	Demand side response / Demand side management
DUoS	Distribution Use of System
EHP	Electric heat pump
ETI	Energy Technologies Institute
EFR	Enhanced Frequency Response
EfW	Energy from Waste
ESME	Energy System Modelling Environment
EV	Electric vehicle
FCEV	Fuel Cell Electric Vehicle
FOM	Fixed O&M

FR	Frequency Regulation
GDUoS	Generator Distribution Use of System
GSMR	Gas Safety Management Regulations
GSP	Grid Supply Point
GWP	Global Warming Potential
HHM	Half-hourly metered
HP	Heat Pump
HV	High Voltage
I&C	Industrial and Commercial
ICE	Internal Combustion Engine
IMRP	Iron Mains Replacement Programme
LCOE	Levelised cost of energy
LP	Low pressure
LRMC	Long run marginal cost
LTS	Local Transmission System
LV	Low Voltage
MP	Medium Pressure
MPAN	Meter point administration number
MV	Multi vector
NG	National Grid
NPG	Northern Power Grid
NPV	Net Present Value
NTS	National Transmission System
O&M	Operation and maintenance
OCGT	Open Cycle Gas Turbine
PEM	Polymer electrolyte membrane
PHEV	Plug-in hybrid electric vehicle
PiV	Plug-in vehicle
PLC	Programmable Logic Controller

PPA	Power Purchase Agreement
RIIO	Revenue = Incentives + Innovation + Outputs, *(the Ofgem gas network cost model)*
SAP	Standard Assessment Procedure
SMR	Steam methane reformer
SNG	Synthetic natural gas
SO	System Operator
SRMC	Short run marginal cost
SV	Single vector
ToU	Time of Use
TUoS	Transmission Use of System
VDH	Virtual district heating
VOA	Valuation Office Agency
VOM	Variable O&M

5 Technical Appendices

5.1 Appendix A: Hydrogen injection into the gas grid

The current limit on the permitted H2 concentration in gas in the gas network is a barrier to the use of surplus renewable electricity for large-scale electrolysis and hydrogen injection. In the following we consider the extent to which the H2 concentration limit constrains the amount of hydrogen that could be accommodated in the network and the implications for where in the network hydrogen could be injected.

The current Gas Safety (Management) Regulations 1996 (GS(M)R stipulate a limit on the hydrogen content of natural gas in the national transmission system of 0.1%mol. In their Future Energy Scenarios forecasts, National Grid refer to the potential for hydrogen to be injected into gas distribution systems in small quantities, up to 2% by volume. However, for meaningful quantities of hydrogen to be injected into the gas grid, this limit would need to be raised further. We first consider the technical factors that might determine the extent to which this limit can be increased.

Technical basis of H_2 concentration limit

The constraint from the perspective of high pressure gas transmission results from the risk of embrittlement of the pipeline. This is generally quoted as 20% hydrogen by volume. A 2015 HSL report concludes that concentrations of hydrogen in methane of up to 20% by volume are unlikely to increase risk from within the gas network from gas appliances to consumers or members of the public.

However, there are still some important areas where issues remain, as follows[108]:

- There are risks associated with bacterial growth in underground gas storage facilities leading to the formation of H_2S. A limit value for the maximum acceptable hydrogen concentration in natural gas has not yet been determined.
- Steel tanks in natural gas vehicles: specification UN ECE R 110 stipulates a limit value for hydrogen of 2% by volume. However, the industry is moving to Type 4 carbon fibre tanks which can accommodate hydrogen at any concentration.
- Gas turbines: most of the currently installed gas turbines were specified for a H2 fraction in natural gas of 1% by volume or even lower. 5% may be attainable with minor modification or tuning measures, some new or upgraded types will be able to cope with concentrations up to 15% by volume.
- Gas engines: it is recommended to restrict the hydrogen concentration to 2% by volume. Higher concentrations up to 10% by volume may be possible for dedicated gas engines with sophisticated control systems if the methane number of the natural gas/hydrogen mixture is well above the specified minimum value. Clarke Energy have quoted a current limit of 4% hydrogen. With R&D it may be possible to get this limit increased.
- Many process gas chromatographs will not be capable of analysing hydrogen. Emerson have recently obtained Ofgem approval for a new gas chromatograph that can meet Ofgem accuracy requirements including hydrogen.

On the basis of the challenges outlined above and assuming appropriate R&D effort, a H_2 limit of 10% might be a reasonable yet conservative assumption for the longer term.

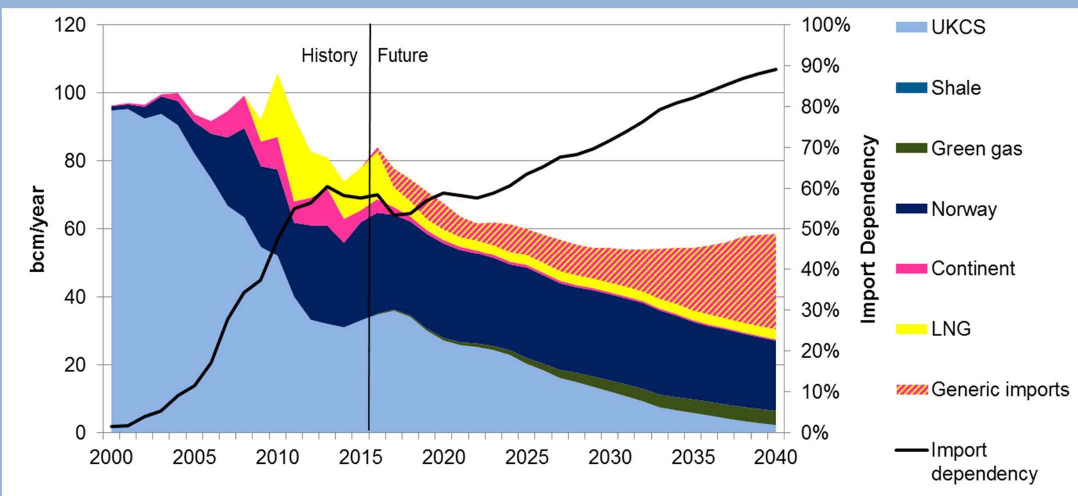
[108] Admissible hydrogen concentrations in natural gas systems, Altfeld & Pinchbeck,

Accommodating H_2 in the GB gas grid

The RES to H2 Case Study (Section 3.2) has identified an economic scale of electrolyser of around 300 MW, based on the projected wholesale price of H_2 in 2050, electrolyser economics and renewables curtailment duration curve. At the minimum required load factor this scale of electrolyser would produce around 1 mcm/d of hydrogen on average, with potential for 1.6 mcm/d at full output. For context, the National Grid's Gone Green future energy scenario envisages an annual gas demand of 59 bcm in 2050, with an average of 169 mcm/d. This is expected to result in a daily minimum demand of around 100 mcm/d. While the overall level of H_2 production suggested in the RES to H2 Case Study is small in the context of this overall 2050 gas demand projection, there may still be local constraints at the point of injection that merit consideration.

Assuming a maximum level of hydrogen injection of 1.6 mcm/d at a particular location on the national transmission system (NTS) and a limit of 10% hydrogen by volume, this implies the need for 14.4 mcm/d of natural gas flowing reliably through that point in order to avoid curtailment. In addition to the main system entry points, the most likely places for this level of regular gas flow are certain multi junctions and compressor stations where pipelines converge and the gas is mixed. Furthermore, if shale gas takes off in the UK, it may also be possible to blend hydrogen with shale gas prior to entry into the gas network.

Natural gas supply points in 2050 – Gone Green scenario



The main entry points for gas into the UK system might provide attractive points for hydrogen injection, given the large natural gas throughput. There is a lot of uncertainty around gas sources in 2050. Based on the National Grid Gone Green scenario out to 2040, indigenous UKCS supplies are likely to be largely depleted, with import dependency potentially 90% or above (subject to the growth of fracking and green gases). Imports are likely to be provided from Norway, LNG and via the continental interconnectors. Of these, Norwegian gas (probably via St Fergus in Scotland and/or Easington on the Yorkshire coast) are likely to be the more consistent through the year, with LNG and continental imports flexing according to market prices. St Fergus and Easington, in particular, may be well located relative to likely locations of spare wind capacity.

In summary, it should be possible to identify a small number of good locations at this level of required gas flow. Clearly this would become more challenging if the limit on hydrogen within the mix was tighter than the 10% assumed above. At 5%, there would be a need for natural gas flows of 30 mcm/d, which may not be feasible throughout the year at any location on the NTS. At 2%, 78 mcm/d would be needed, which could be problematic in all locations at any time of the year. National Grid's 2050 Gone Green scenario forecasts a far higher quantity of hydrogen produced by electrolysis than we have identified in this Case Study, at 15 TWh/y of H_2 production. This implies around 12 to 13 electrolysers of the scale considered in our analysis. Note that based on the Gone Green scenario gas demand in 2050, these electrolysers could not all be accommodated on the network at a maximum H_2 blend of 10%.

5.2 Appendix B: CO_2 Based Heat Pumps

For a given property, the heat lost by that property at a comfortable temperature (here we assume 15℃) is a decreasing linear function of ambient temperature, shown below. A building's radiators and boiler are sized to provide this heat at flow and return temperatures of 75/60℃ or 81/72℃; a temperature difference at the radiators and the room of 52 and 60℃.

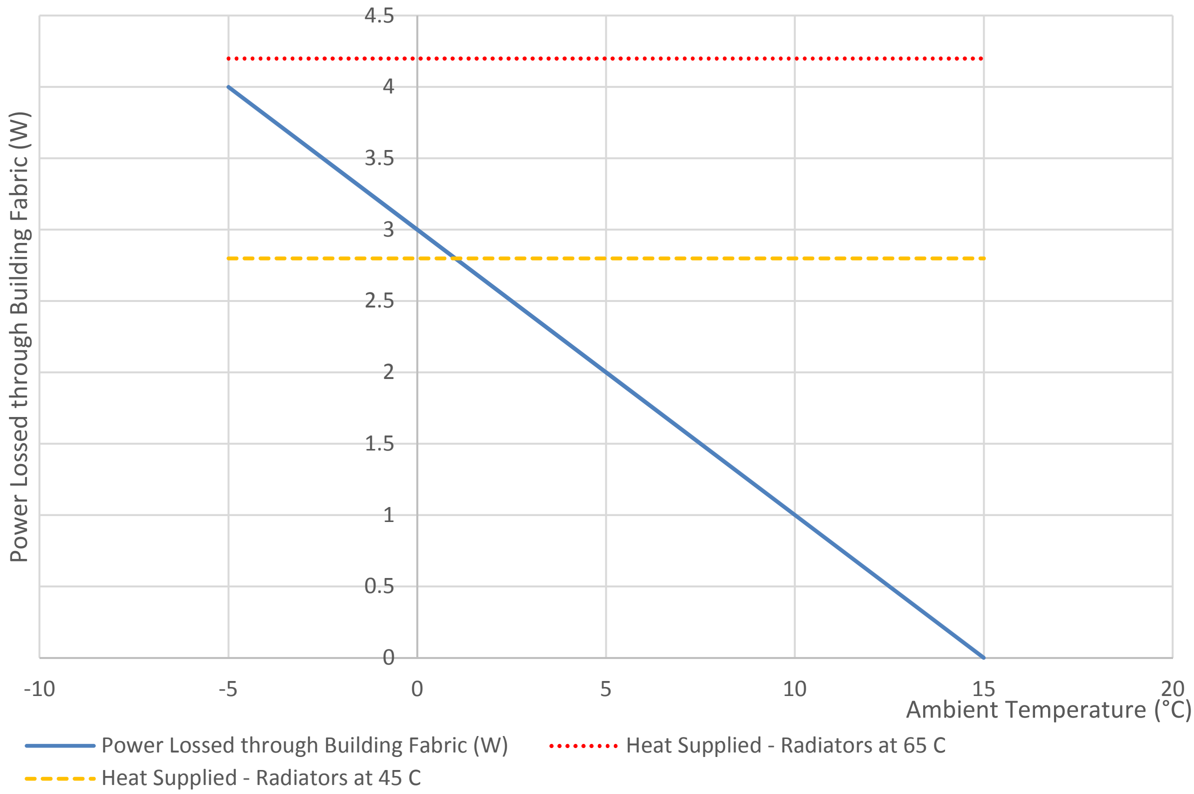


Figure 71 -

Define the **bivalent point** as the ambient temperature above which the property's radiators, operating at a flow temperature of 45℃, can supply sufficient heat to maintain it at 15℃. Experience shows that where the bivalent point is above 2℃, the heat pump will not run sufficiently that fuel savings pay back its capital costs; at around -1℃, they may.

This illustrates the problem with low temperature heat pumps in houses built between 1990 and 2004; these houses have radiators (and in some cases, pipes) that do not have sufficient capacity to supply winter heat operating at 45℃; and their thermal insulation may be less easy to improve. Microbore pipes are a particular problem, as flow rates must be higher for lower delta T. (Had these systems been built for condensing boiler operation, with a return temperature of 55℃ or less, this would not be a problem).

As of February 2017, the main technological focus of heat pump manufacturers, is not increased CoP but reducing the GWP of used refrigerants, in particular, the EU F Gas regulations mean that suppliers must reduce by 33% in the next 18 months the GWP of their total refrigerant throughput. This means that there is a strong focus on switching to ammonia or, for domestic applications, CO_2. CO_2 heat systems must operate at a much greater delta T – and are therefore suitable for the housing stock above.

6 Case Specific Model Technical Appendices

6.1 Case Study 1

6.1.1 Appendix C: Smart Multi Vector – Simultaneous LV and HV Load Management

In the **Smart Multi Vector** implementation, hourly loads at primary (HV) and secondary (LV) substations are monitored, with heat pump demand turned down in response to capacity constraints at either. However, where a HV primary substation and connected LV substations require simultaneous demand management, only the larger amount of:

1. The HV fuel switching
2. The sum over downstream LV fuel switching

Need be considered for each model timestep[109].

The 2050 managed load totals at the 16 primary substations, and the sum of managed load over their connected LV substations are shown below; those substations at which primary demand dominates secondary demand are indicated in **bold**.

Table 100 – Total 2050 Primary and Downstream Secondary Heat Pump Demand Shifted to Gas, Smart MV Scenario

Substation	Primary Shifting (MWh)	Secondary Shifting (MWh)	Electrical Heat Supply Fraction[110]
Benwell	325.3	5,965.7	86.6%
Blucher	158.8	1,430.5	95.2%
Breamish Street	0.0	348.9	97.4%
Close	0.0	597.9	85.0%
Corporation Street	0.0	90.7	99.5%
Educational Precinct	0.0	297.8	98.4%
Fawdon	320.5	2,817.4	90.6%
Fossway	8,186.0	3,424.7	84.6%
Kenton	2,580.7	1,794.1	94.3%
Longbenton	1,885.5	387.7	95.6%
Newburn Haugh	0.0	526.5	94.4%
Newcastle Airport	0.0	2,313.6	70.5%
Pilgrim	0.0	193.2	96.8%
University	0.0	3.6	99.8%
Walker	230.5	2,507.7	83.1%
Westerhope	7,362.1	3,488.6	86.5%

[109] This corresponds to an implementation requirement that the control system is sufficiently sophisticated to include the network topology.

[110] The Electrical Heat Supply Fraction is the share of thermal demand met electrically across buildings equipped with heat pumps and connections to the gas network.

7 Appendix D: Summary of Assumptions and Data Sources

7.1 Case Study 1

Case Study 1 models the grid upgrade costs associated with the large-scale electrification of heat.

Table 101 - Key Data

Parameter	Data Source	Comment
Network Structure	HV to LV substation connections taken from EPN data. HV and LV feeder connections to buildings synthesised in EPN, described below.	
Substation appliance profiles	Existing 2016 demand profiles are taken from a set of HV substation profiles taken from NPG data; LV substations inherit the profile of their upstream primary.	LV substations may be over-diversified. This may affect their potential for storage as a single vector alternative.
EV Charging Profiles	Taken from *National Transport Survey* and *ETI Consumers and Infrastructure EV Project*	
ASHP CoP	Taken from the Emerson Climate *Copeland* and *Select* models, and given in appendix 8.2.	May be high, as they are based on manufacturer data and not field trial data, this effect has been investigated in the model.
Heat demand profiles	Taken from Carbon Trust Profile (in appendix 8.1.1) for both domestic and I&C users.	The same profiles are used for domestic and I&C demand, this likely slightly overstates peak electric heating demand.

Table 102 –Simplifying Assumptions

Parameter	Assumption	Comment
Flow Temperatures	Buildings constructed before 2004 are assumed to require a flow temperature of 70℃, new build a flow temp of 55℃	A flow temperature of 70℃ may only be possible at the CoP values modelled using a CO_2 heat pump, described in appendix 5.2.
GSHP and WSHP CoP	Assumed to take a year-round value of 3.	

7.2 Case Study 2

Case Study 2 considers district heat supply under a range of future energy system price forecasts.

Table 103 – Case Study 2 Data Sources

Parameter	Reference Values	Comment
Electricity and Gas Prices, Carbon Intensities	Taken from Decarbonisation Scenario, described in appendix 9.1.2.	The sensitivity to higher, less volatile prices for a less decarbonised system are also considered.
Carbon Prices	CCC Price projections	BEIS central and high carbon price scenarios are also considered,
Plant Capital and Operating Costs, and efficiencies	Taken from a literature review, carried out as part of the CCC project on *Research on District Heating and Local Approaches to Heat Decarbonisation*	Values for high performance ground source heat pump used.
Thermal demand profiles	Space heat profiles from Carbon Trust Profile (in appendix 8.1.1) for both domestic and I&C users, hot water demand profiles are taken from the Energy Saving Trust report *Measurement of Domestic Hot Water Consumption in Dwellings* and diversified as described in appendix 8.4	

Table 104 – Case Study 2 Simplifying Assumptions

Parameter	Assumption	Comment
CHP Carbon Intensity	CHP cogeneration is assumed to offset peak (thermal gas) plant; given the SRMC of renewable generation, and that CHP generates only when prices are above some positive minimum this is a fair assumption for a decarbonising electrical system. At around 45% CCGT efficiency this equates to around 400g CO_2/kWhe.	Grid average offset is also considered – grid average carbon intensity values are taken from BEIS data. Between them, these likely comprise upper and lower bounds
Low Carbon Plant Size	Low carbon plant is not sized to over 50% of peak scheme thermal demand.	This is based on discussions with existing heat network operators.
Network Temperatures	New build assumed to operate at a flow temperature of 60℃, existing at 75℃	

7.3 Case Study 3

Case Study 3 considers fuel switching of hybrid vehicles at times of electrical system constraint.

Table 105 – Case Study 3 Data Sources

Parameter	Reference Values	Comment
Vehicle Parc	Taken from ECCo model, run as for CVEI projects	
Vehicle liquid fuel and electric efficiencies		
Total fuel demands and infrastructure requirements		
Electrical prices	Taken from PLEXOS model, taken from a constrained period of low wind speed	
Liquid Fuel Supply Margin	A value of 6p/litre used, taken from a Wood-Mackenzie study	

7.4 Case Study 4

Table 106-Case Study 4 ESME2PLEXOS model input data

Parameter	Reference Values	Comment
Wind load factor hourly profiles	Exogenous wind load factor data of different regions in the UK based on Anemos database, which produces simulated wind speed data based on historical weather data (2008). Subsequently mapped to the ESME UK regions.	Same as profile used in ETI's CVEI project
Solar and tidal hourly profiles	Exogenous data obtained from the work Baringa undertook on ETI's CVEI project	Data provided by the ETI for the CVEI project
Hourly demand profile	Time-sliced demand data from the ESME v4.1 model, smoothened using a Gaussian filter	Same as profile used in ETI's CVEI project
Plant technical data	As per ESME v4.1 database and when not available, directly provided by the ETI for use in the CVEI project	Same as profile used in ETI's CVEI project
Interconnectors	Interconnectors to Norway, Netherlands, France and Ireland sized as in ESME v4.1 Reference Case and considered fixed across	

	all scenarios. Interconnector markets modelled in PLEXOS based on a fixed price data series calibrated from the Baringa Pan-EU PLEXOS model.	

Table 107-Case Study 4 Economic sizing of multi vector and counterfactual technologies input data

Parameter	Reference Values	Comment
Electrolyser Capex, VOM, fixed costs, economic data	As per ESME v4.1 database	The sensitivity to lower capex was also considered
Electrolyser efficiency	As per figure quoted in Leeds City Gate H21 project report.	This is higher than the value found in ESME v4.1
H2 price	H2 shadow price given by ESME for each scenario	The sensitivity to higher H2 price was also considered, including the value quoted in Leeds City Gate H21 project report
Electricity price	Electricity prices were assumed to be zero at times of curtailment	
Methanation Capex	Assumed to be 64% higher than electrolysis based on relative increase in corresponding values quoted by ENEA Consulting	See "The potential of Power-to-Gas", ENEA consulting, January 2016"
Methanation efficiency	Assumed to be 20% lower than electrolysis based on efficiency loss derived from electrolysis vs methanation values quoted by ENEA Consulting.	See "The potential of Power-to-Gas", ENEA consulting, January 2016"
Methanation VOM, fixed costs, economic data	VOM and economic data as per ESME v4.1 using electrolysis data. Fixed costs as per ESME v4.1 and including an extra 7.5% of methanator capex based on ENEA Consulting.	See "The potential of Power-to-Gas", ENEA consulting, January 2016"
Carbon price	Carbon shadow price given by ESME for each scenario	The sensitivity to different carbon price scenarios was also considered
Gas price	Gas shadow price given by ESME for each scenario	The sensitivity to higher gas price scenarios was also considered
Transmission line capex and economic data	As per ESME v4.1	

Battery capex and economic data	As per ESME v4.1 database assuming a Li-On battery. Variable and fixed costs were assumed zero.	
Electrolysis/ Methanation ramp rate	Assumed to be fully flexible without output level and ramping constraints. This assumption is based on experimental data published by NREL. For simplicity, the same assumption was used for methanation.	See "Novel Electrolyser Applications: Providing more than just hydrogen (NREL)"
Scenarios of additional revenues from ancillary services: Utilisation and availability fees, technical requirements	Minimum requirement for participation in flexibility services based on National Grid's website. Availability and utilisation fees based on Baringa's internal analysis of historical data and National Grid publicly available data	http://powerresponsive.com/wp-content/uploads/pdf/power-responsive-dsr-product-map-glossary-161215.pdf, http://www2.nationalgrid.com/uk/services/balancing-services/

7.5 Case Study 5

Table 108-Case Study 5 Input Assumptions

Parameter	Reference Values	Comment
Hourly heating demand profile	Hourly demand shape given by the Carbon Trust micro-CHP field trials for domestic and non-domestic customers. Diversification factors for domestic and non-domestic demand assumed to be 25% and 10% respectively. The split between domestic and non-domestic demand was assumed to be 63% and 37% respectively, per Leeds H21 report.	See Leeds H21 Project Report and "Case Study Model Data" Appendix
Yearly H2 demand	Used figure quoted in the Leeds H21 project report as the worst-case conditions annual gas consumption of the Leeds conversion area.	Derived by adjusting annual demand observed in 2013 for the coldest average temperatures observed in the area the last 30 years. Conversion efficiency for gas and H2 boilers assumed the equal.
1-in-20 peak H2 demand	Used figure quoted in the Leeds H21 project report for the area of conversion	See Leeds H21 Project Report
Electrolyser Capex, VOM, fixed costs, other economic data	As per ESME v4.1 database	The sensitivity to lower capex was also considered

SMR Capex, VOM, fixed costs, other economic data	As per ESME v4.1 database	The sensitivity to lower capex was also considered
Electrolyser and SMR efficiency	As per figure quoted in Leeds City Gate H21 project report.	The efficiency for electrolysis found in H21 report is higher than the value found in ESME v4.1. See Leeds H21 Project Report.
Electricity price	Electricity prices as per ESME2PLEXOS prices corresponding to ESME Scenario 3	The sensitivity to lower prices was also considered. See also appendix 9.
Gas price	Gas shadow price given by ESME for ESME Scenario 3.	
Electrolysis ramp rate	Assumed to be fully flexible without output level and ramping constraints (ramp rate at 100%). This assumption is based on experimental data published by NREL.	See "Novel Electrolyser Applications: Providing more than just hydrogen (NREL)"
SMR rate	SMR assumed to be able to ramp up/down their output by 5% per hour according to the Leeds City Gate H21 project report.	See Leeds H21 Project Report
H2 transmission line capex and economic data	As per ESME v4.1 for the value per unit of capacity per km and assuming a total length of 190km of H2 transmission system as the one envisaged in the Leeds H21 project.	See Leeds H21 Project Report
H2 storage Capex, VOM, fixed costs, other economic data	As per ESME v4.1 database based on average values derived using data for shallow, medium, deep salt cavern H2 storage.	
H2 storage minimum time for full charge/discharge (storage volume to power ratio)	Derived based on the characteristics of intra-day storage designed for the Leeds H21 project.	The sensitivity to higher values based on the characteristics of seasonal storage designed for the Leeds H21 project were also considered. See Leeds H21 Project Report.

7.6 Case Study 6a

Table 109-Case Study 6 Input Assumptions

Parameter	Reference Values	Comment
Hourly heating demand profile	Hourly demand shape given by the Carbon Trust micro-CHP field trials for domestic and non-domestic customers, as per Case Study 5, assuming same diversification factors for domestic and non-domestic demand and same split between domestic and non-domestic demand. Scaled down by a factor of 100 assuming that the area is 1% the size of the area of conversion in the Leeds H21 project.	
Yearly and 1-in-20 peak H2 demand	Both based on demand levels in Case Study 5, scaled down by a factor of 100. To convert from H2 demand to thermal (heating) demand, the efficiency of gas boilers was assumed to be 80%.	
Electricity price	Electricity prices as per ESME2PLEXOS prices corresponding to ESME Scenario 3	See appendix 9.
Wind load factors	As in Case Study 4.	
Substation electricity demand hourly profile	Based on an Element Energy typical substation load profile.	
Heat pump Capex, VOM, other economic data	As per ESME v4.1 assuming a ground-source heat pump with the exception of COP assumption being based on Element Energy's study on District Heating.	See https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/502500/BEIS_Heat_Pumps_in_District_Heating_-_Final_report.pdf
Thermal storage Capex, VOM, other economic data	As per ESME v4.1 with the exception of capex for storage volume which is based on a study undertaken by Tyndall Centre	See http://www.tyndall.ac.uk/sites/default/files/twp157.pdf
Primary transformer and cable cost capex and economic data	Based on average values for distribution network HV asset costs found in ETI's Energy Path Networks (EPN) database	

7.7 Case Study 6b

Case Study 6b assesses the value of Smart Electric Thermal Storage (SETS)

Table 110 – Case Study 2 Data Sources

Parameter	Reference Values	Comment
Electrical Price	Taken from Decarbonisation Scenario, described in appendix 9.1.2	2020 values used.
Carbon Price	Taken from BEIS central scenario for 2020, at a value of £45/tonne	
Storage Heater Capital Costs	Taken from discussion with Glen Dimplex.	
SETS Control Costs	Taken from the Element Energy report for National Grid *Frequency Sensitive Electric Vehicle and Heat Pump Power Consumption*	Value for heat pump used, this may slightly overstate the control costs.
Thermal Demand profiles	Taken from Carbon Trust Profile. Economy tariff heating profiles given by scaling daily demand to off peak hours.	
Substation Demand	Taken from EE Substation Demand Curves, scaled to an appropriate peak-to-average value.	
Thermal Demand Totals	Taken from SHCS Energy Use in the Home, 2012 - estimate for 2010 breakdown, and scaled to HDD data for appropriate UK areas.	

7.8 Case Study 7

Table 111-Case Study 7 Input assumptions

Parameter	Reference Values	Comment
Anaerobic Digestion conversion efficiency values	Waste to gas: As per ESME v4.1 database for an Anaerobic Digestion Gas plant Waste to electricity: As per ESME v4.1 database for an Anaerobic Digestion CHP plant	
Waste gasification conversion efficiency values	Waste to gas: Based on information provided by Progressive Energy Waste to electricity: As per ESME v4.1 database for a Waste Gasification plant	
capex and fixed costs of gas injection plants	Based on unit price and fixed cost figures provided by Progressive Energy.	Assumed the same for both anaerobic digestion and waste gasification plants
capex and fixed costs of CHP plants	As per ESME v4.1 for a Macro-CHP plant.	Assumed the same for both anaerobic digestion and waste gasification plants
Deterministic electricity price profile	Hourly electricity prices as per ESME2PLEXOS prices corresponding to ESME Scenario 3.	See “Exogenous Model data” Appendix
Deterministic gas price profile	Based on gas shadow price for ESME Scenario 3 and shaped by using historical volatility of gas prices.	

8 Appendix E: Case Study Model Data

Data used across models is presented and explained below.

8.1 Hourly Demand Profiles

8.1.1 Domestic Thermal Demand

The Carbon Trust Micro-CHP profiles were given by the average thermal demand across around 20 houses, and averaged across weekdays and weekends[111], and are shown in

8.1.2 Domestic Hot Water Demand

Domestic hot water demand profiles are taken from Energy Saving Trust report *Measurement of Domestic Hot Water Consumption in Dwellings,* and shown in Figure 2.

8.1.3 Elexon Class 2 Profile

The Elexon Class 2 profile is used for settlement of homes on the Economy 7 and Economy 10 tariffs, and gives an estimate of hourly electrical demand for storage heater properties.

8.2 CoP Data

Heat pump CoP data are taken from the Emerson Climate *Copeland* and *Select* models.

Table 112 - ASHP CoP

		Sink Temperature (°C)								
		30	35	40	45	50	55	60	65	70
Source Temperature (°C)		3.76	3.34	2.96	2.62	2.32	2.06	1.65	1.31	1.10
	0	4.52	4	3.53	3.11	2.74	2.41	2.13	1.88	1.65
	5	5.42	4.78	5.91	5.37	4.82	4.28	3.95	3.62	3.29
	10	6.51	5.71	6.73	6.80	5.46	4.83	4.44	4.43	3.65
	15	7.81	6.82	7.44	6.73	6.62	5.39	4.94	4.49	4.25
	20		9.41	8.59	7.72	6.85	5.97	5.47	4.98	4.49

8.3 Plant Efficiency Data

Plant	Thermal Efficiency	Electrical Efficiency
Gas CHP	54%	24%
Gas Boiler	85%	-

[111] Demand for space heating and hot water, but not heat for cooking, see https://www.carbontrust.com/media/77260/ctc788_micro-chp_accelerator.pdf

8.4 Demand Diversification

8.4.1 Thermal Peak

District heating plant and network are sized based on a diversified peak demand factor; in line with CIBSE guidelines, system level peak demand is determined from the aggregate individual peak demands using the formula:

$$D = B + (1 - B)e^{-An}$$

Where

D is the peak diversification factor; the fraction given by the system peak demand over the sum of individual peaks,
A and B are empirical constants, taking values 0.05 and 0.2 respectively, and
n is the number of scheme connections.

8.4.2 Electric Networks

Domestic electrical appliance and heating loads (the After-Diversity Maximum Demand (ADMD)) are shown below, we note that currently no diversification is applied to heat pumps.

Table 113 - NPG Diversification Factors for Domestic Electric Loads[112]

Customer Type	ADMD
General Domestic	2kW (day) 0.5kW (night)
Storage Heaters	2kW + 10% of installed heating (day) 2kW + 60% of installed heating (night)
Direct-acting space heating (DASH)	1kW + 50% of installed DASH load
Other electrical heating (including HP)	1kW + 100% of installed load

8.5 DH Plant and Network Costs

Network Costs

To determine the price of heat, network capital costs are also calculated using an $L(\mathrm{Ar} + \mathrm{B})$ model, where r is the pipe radius, L is the pipe length and A and B take values £10,000/m^2 and £250/m respectively. Network operating costs are taken as 0.4% capex annually.

Table 114 – 2021 Heat Pump Costs by MW, unused model data shown in grey

HP Type	capex (£/MW)	Opex (%Capex/year)
Air Source	1,151,000	0.5%
Water Source	1,380,000	0.5%
Ground Source	1,918,000	0.5%

[112] Code of Practice for the Economic Development of Low Voltage Networks - IMP001911

Table 115 - Gas CHP Engine Costs by MW, unused model data shown in grey

Plant Size Band (MW)	capex (£/MW)	Opex (%Capex/year)
< 0.1	1,001,000	9%
0.1 to 12	844,000	8%
12 to 24	720,000	7%
24 to 36	656,000	6%
36 to 48	656,000	5%
>48	630,889	4%

8.6 Boilers Costs

Per kW costs are shown below, operating costs are charged at 5%/year; system costs also include a £50 gas meter cost, and a £500 installation and gas network cost.

Table 116 - Local Boiler Cost Components

Boiler Size (kW)	£/kW
1-24	50
24-50	45
>50	40

8.7 Grid Time of Use Charges

HV half hourly metered (HHM) users are subject to a fixed charge of between 50p and £1.50 per day. DNOs distribute their remaining existing amortisation and future infrastructure costs across their users on a marginal (per kWh) basis, with demand during peak red periods (corresponding to weekday evenings) particularly emphasised by time-of-use tariffs.

Generators pay a similar amount to use to the HV network, and may then be remunerated on a ToU per unit delivered basis, depending on the topology and capacity of their connecting circuit.

The DNO generator rebate, referred to as Generator Distribution Use of System (GDUoS) charges, vary considerably with by intermittency and across DNO areas; a range of DUoS charges and their associated GDUoS values are shown below.

I&C gas network connections are paid for under a similar structure; users pay to connect and then pay a daily standing charge, which covers some part of the Ofgem regulated network O&M and upgrade costs.

Table 117 –Time of Use Periods for HV Connected, HHM Users and Generators, WPD East Midlands

	Green Time Band	Amber Time Band	Red Time Band
Weekdays	00:00 to 07:30 21:00 to 24:00	07:30 to 16:00 19:00 to 21:00	16:00 to 19:00
Weekends	00:00 to 24:00		

Table 118 –Time of Use Network Charges and Revenues (£/MWh), WPD East Midlands

DNO and Area	ToU Tariff	Red	Amber	Green
WPD East Midlands	DUoS Charge	74.25	1.15	0.21
	GDUoS (Intermittent Generators)	-3.33	0.00	0.00
	GDUoS (Non Intermittent Generators)	-29.55	-1.97	-0.14
NPG (Yorkshire)	DUoS Charge	26.91	12.23	9.8
	GDUoS (Intermittent Generators)	-3.15	0.00	0.00
	GDUoS (Non Intermittent Generators)	-18.7	-3.28	-0.33
Eastern Power Networks	DUoS Charge	55.34	1.42	1.11
	GDUoS (Intermittent Generators)	-5.63	0.00	0.00
	GDUoS (Non Intermittent Generators)	-60.59	-0.50	-0.09

Table 119 –WPD East Midlands DNO Area Retail Margin Composition (£/MWh) by Year

Retail Electricity Bill	2016	2020	2024	2028	2032	2036	2040
Average Wholesale Power Price	38.7	41.1	46.9	46.0	49.6	50.5	55.0
Capacity Mechanism	0.0	3.5	5.4	4.7	4.0	2.4	2.3
BSUoS	2.0	2.0	2.0	2.0	2.0	2.0	2.0
TNUoS	2.5	3.7	4.1	4.3	4.5	4.7	4.8
Losses (T&D)	1.6	1.7	2.0	2.0	2.1	2.2	2.3
AAHEDC	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Supplier margin	1.8	1.8	1.8	1.8	1.8	1.8	1.8
ROC	11.6	13.1	11.9	10.5	8.5	0.0	0.0
FiT	3.5	3.8	3.8	3.7	2.1	0.0	0.0
CfD	1.2	5.8	6.1	9.0	11.2	8.6	9.4
CCL	5.6	5.6	5.6	5.6	5.6	5.6	5.6

9 Exogenous Model Data

9.1 Appendix F: ESME Cases

9.1.1 Baringa Internal Reference Case prices

Electrical Prices

The hourly electricity prices are derived with Baringa's in-house PLEXOS model simulating a power market model with all generators bidding into the GB power market. The Reference case represents Baringa's central view on the evolution of the GB power market using internal assumptions on plant closures, conversions and new plant and interconnector build. Under this scenario, the Government continues to pursue a balanced energy policy, attempting to meet the sometimes competing demands of security of supply, competitive market structure, and environmental sustainability. In terms of demand assumptions, the average demand of the four National Grid Future Energy Scenarios (FES) 2016 is adopted. The full power price is formed based on the marginal cost of the marginal generation in each hour, on which a scarcity rent is added to represent the impact of tighter capacity margins on power prices (with the scarcity rent function calibrated to historically observed values).

Gas Prices

Gas prices follow the forward curve to 2017 based on Platts NBP forward for GB, then trends to 76 p/th (£25.90/MWh) in 2040, with this long term price target being based on the IEA's 2015 WEO "New Policies" scenario (Europe imports) price. These gas prices do not include a carbon price component.

Carbon Price

We assume that the full costs of carbon are passed through into the power price, and carbon prices are therefore a major value driver, particularly for non-fossil-fired generation plant. The Reference case reflects a world in which carbon abatement is achieved largely in the power sector through coal-to-gas switching, as the EUA price steadily rises towards 50 €/t by 2040. GB Carbon price is modelled as a sum of the EUA price and CPS tax, reaching 41£/tonne in 2040.

9.1.2 Baringa Internal Decarbonisation scenario prices

Electrical Prices

In the Decarbonisation case, we explore a scenario in which Government is successful in implementing policies which bring forward further investment in low carbon generation (renewables, nuclear and CCS), and hence these targets are met. It explores the impact of deep decarbonisation in the GB power market and in particular the impact on power prices. In terms of demand assumptions, the most recent trajectory from National Grid Gone Grid scenario is adopted. Peak electricity demand is assumed to grow at the same rate as the same FES scenario. The full power price is formed based on the marginal cost of the marginal generation in each hour, on which a scarcity rent is added to represent the impact of tighter capacity margins on power prices (with the scarcity rent function calibrated to historically observed values).

Gas Price

The Baringa Decarbonisation scenario follows the Reference case forward curve, then trends to the IEA "450" scenario price of 55 p/th (£18.80/MWh) in 2040. These gas prices do not include a carbon price component.

Carbon Price

We assume that the full costs of carbon are passed through into the power price, and carbon prices are therefore a major value driver, particularly for non-fossil-fired generation plant. In the Decarbonisation case the price reaches 105 €/t in 2040 as per the IEA's "450 ppm" scenario EUA price, driving more aggressive emissions-abating investment. GB Carbon price is modelled as a sum of the EUA price and CPS tax, reaching 86£/tonne in 2040.

9.1.3 ESME and ESME2PLEXOS prices

Electrical Prices

For the purpose of Case Study 4, three different whole-energy system scenarios were generated using ESME v4.1 by constraining the 2050 build capacity of onshore and offshore wind to the desired minimum levels in each scenario, i.e., enforcing minimum levels of installed wind capacity in the pathway optimisation model. These scenarios were produced in an attempt to examine the impact of the large penetrations of wind in the system on the level of curtailed renewables. The ESME results in each modelled 2050 scenario include the installed generation capacity mix, electricity demand per seasonal and diurnal time-slice, as well as the required transmission capacity between UK regions allowing transmission of power to centres of demand. The ESME2PLEXOS tool is subsequently used to link ESME to PLEXOS in order to determine the minimum cost electricity dispatch at an hourly level in the country as well as the hourly electricity prices corresponding to each ESME scenario.

The capacity mix in each of these three energy system scenarios is shown in the following table and graph.

Table 120 – ESME UK Generation Mix Projections

Generation capacity (GW)	ESME V4.1 Ref. Case	ESME Scenario 2 (medium)	ESME Scenario 3 (high)
Onshore wind	13	20	20
Offshore wind (fixed)	5	20	40
Offshore wind (floating)	6	20	30
Hydro	3	3	3
Tidal	3	1	1
Total (GW)	**30**	**64**	**94**

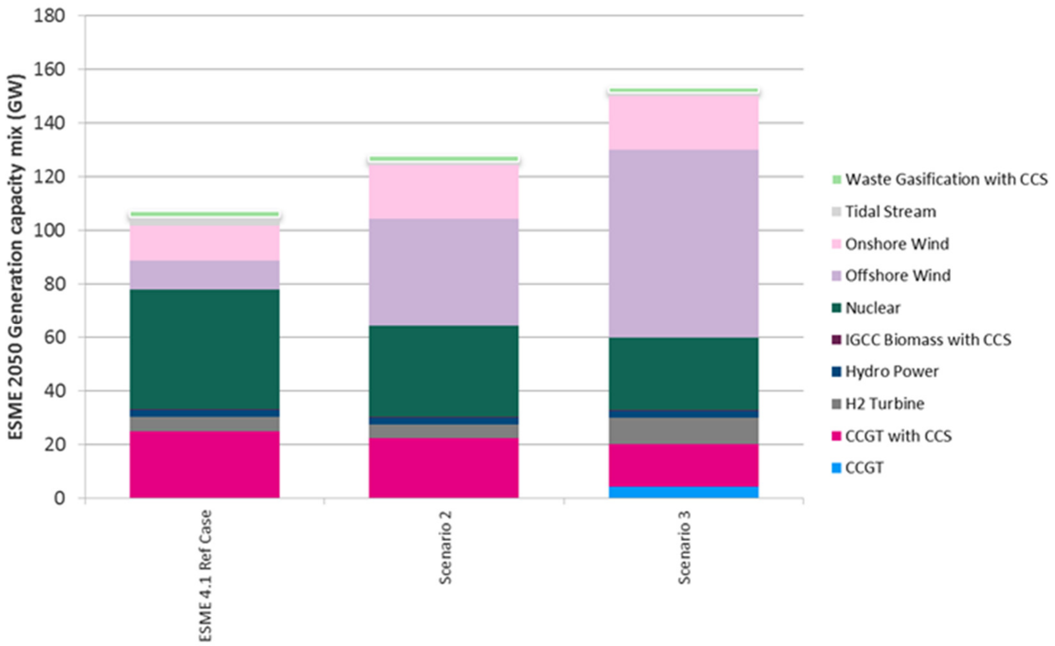


Figure 72 – UK Generation Mix Composition

The analysis in case studies 5, 6a and 7 is based on the electricity price profile derived from PLEXOS for ESME Scenario 3, otherwise referred to as "ESME High Scenario" throughout this report and considered as the Base Case energy system scenario for the aforementioned case studies. Case Study 4 does not explicitly use the hourly profile of electricity prices except for the case where the average electricity price was used in calculating the potential revenues of electrolysis through ancillary services.

Gas Price

For each ESME scenario generated in Case Study 4 (Ref. Case, Scenario 2, Scenario 3), ESME provides a shadow price for natural gas, representing the cost of producing an extra natural gas unit in the system. This has been used as a proxy for the wholesale gas price in Case Studies 4, 5 and 7.

Carbon Price

For each ESME scenario generated in Case Study 4 (Ref. Case, Scenario 2, Scenario 3), ESME provides a shadow price for carbon, representing the cost of producing a unit of CO_2 in the system. This has been used as a proxy for the carbon price in Case Studies 4, 5 and 7.

Hydrogen Price

For each ESME scenario generated in Case Study 4 (Ref. Case, Scenario 2, Scenario 3), ESME provides a shadow price for hydrogen, representing the cost of producing an extra hydrogen unit in the system. This has been used as a proxy for the wholesale hydrogen price in Case Study 4.

9.2 Appendix G: Energy Path Network Model

Energy Path Network is a Monte Carlo model which determines lowest cost network upgrade costs associated with a variety of demand projections and generation connections. The costs in EPN are based on data from the ETI Infrastructure Cost Calculator, and scaled to network capacities based on empirical and operational data. The inherited range and uncertainty in infrastructure costs is discussed below.

Network Component Cost Range

Substation and feeder upgrade costs are constructed from individual component costs, such as the cost of a wire or the labour cost of installation. Following the ETI 2050 Energy Infrastructure Outlook project variation in these costs arises from the factors, summarised below:

Site context

The site context is important in determining land or access rights costs, transportation costs, as well as other costs such as costs related to street works, planning and consents costs etc. In the above project these are driven primarily by whether the area is classed as urban, suburban, rural, or London.

Table 121 – ETI Cost Calculator Area Densities

Classification	Dwellings per Hectare
Rural	>30
Suburban	30-60
Urban	>60

Material costs

These refer to the costs of purchasing the network component under consideration and can depend on commodity prices, global/national/regional supply and demand conditions, foreign exchange fluctuations, learning curves for future costs etc.

Labour costs

Labour costs depend on regional labour costs, the skills availability in a particular region, as well as on the complexity of the installation under consideration.

Plant cost

The availability of suitable plant to support the installation of the network would also have an impact on overall costs.

Installation costs

The scale of installation could also have an impact on costs and this will depend on a complex inter-relationship between the sizing and capacity of the overall installation and the various system costs. In general, large installations could bring system costs down through economies of scale and through avoiding duplication of some costs and labour.

Ground conditions – excavation difficulty

Degree of difficulty expected to be encountered in the excavation of trenches and holes during construction.

Ground conditions – ground contamination

Excavated material which requires specialist handling and disposal as a result of chemical contamination contained within the soil.

Ground conditions – ground water conditions

Water requiring intermittent or continuous pumping during construction operations to keep excavated areas safe and dry.

For illustrative purposes, Figure 73 below shows the annualised per km cost of an 11kV underground cable rated at 6 MVA, comprising the sum of:

i. the initial cost
ii. repetitive refurbishment costs at replacement cycles
iii. abandonment cost

assuming a 40 year asset lifetime.

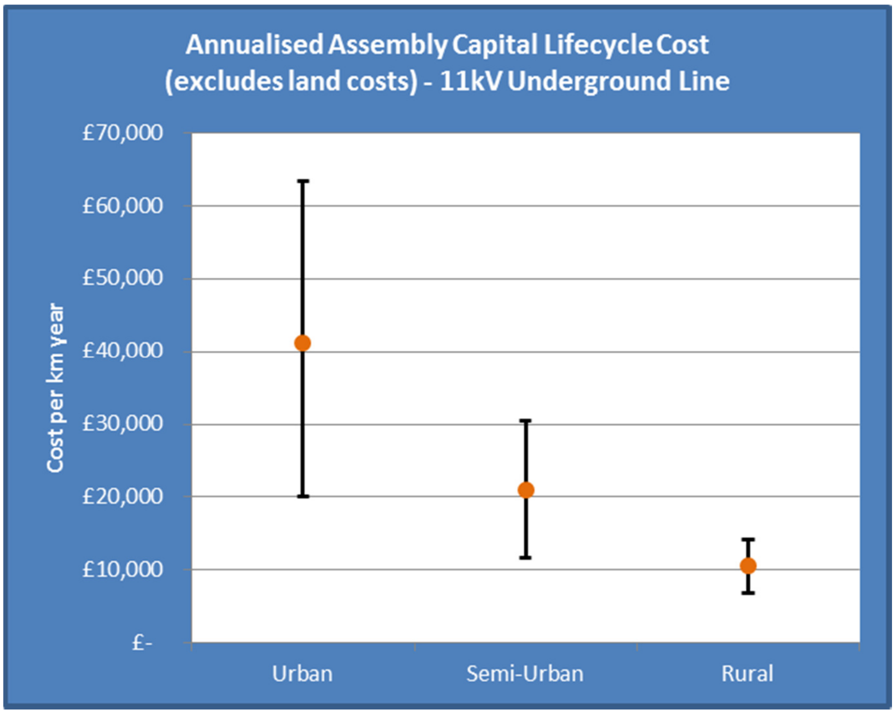


Figure 73 - Annualized cost of an 11kV underground cable (rated at 6 MVA)