Programme Area: Energy Storage and Distribution

Project: Multi Vector Integration

# Title: Multi Vector Integration Study Summary report


## Abstract:

This Deliverable is the report summarising the work during the project overall. 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 continuation 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.


## 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

D6.1 – Summary Report

for

**The Energy Technologies Institute**

10th September 2017

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## Acknowledgements

The authors are grateful to all individuals and organisations that assisted with and provided input to this study. In particular, thanks are due to:

**BEIS**

**Community Energy Scotland**

**EnerNOC**

**Glen Dimplex**

**Honeywell**

**Dr. Ian Madley of Keele University**

**ITM Power**

**Professor Margaret Bates of Northampton University**

**Mitsubishi Electric**

**National Grid**

**Northern Gas Networks**

**Ofgem**

**Passiv Systems**

**Progressive Energy**

**Scottish and Southern Energy (SSE)**

**Upside Energy**

**Xsilon**

Special thanks are due to Northern Powergrid (NPG) and Western Power Distribution (WPD) for allowing us to use their network data in our analysis.

# 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 continuation 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.

## 1.1 Case Study selection

An initial long-list of multi vector interactions were identified following a comprehensive assessment of the 'services' that multi vector interactions could provide across the energy system. These services were broadly classified as follows:

> **Peak avoidance** – demand on one network is substituted for another vector at peak times. This is mainly related to the electricity network.
> **Flexibility** – the system provides ability to flex between vectors due to a range of price signals or constraints on particular networks.
> **Generation capacity constraint** – switch from electricity to a different vector due to constrained generation capacity.
> **Generation curtailment** – curtailment of a generating technology due to lack of network capacity, or energy demand or storage capacity for the area of interest
> **Back-up** – use of an alternative energy vector to back-up a primary source.

The long-list of multi vector interaction opportunities identified across the energy system was then filtered down to a short-list by applying the following prioritisation criteria:

- 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 the detailed analysis:

**Final short-list of Cases Studies:**

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 H2/RES to CH4
5. Grid electricity to H2 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

## 1.2 Case Study definition and analysis

Through the analysis of the case studies, we seek to understand the benefit that the multi vector interaction can provide at a system level, e.g. overall reduction of resource costs. We also consider whether there is a business case at the local level, e.g. a financial case for the direct project participants. In each case, the multi vector system is compared against one or more single vector configurations, which supply the same energy demands. For both single and multi 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.

The Case Study models do not represent the whole energy system; in each case a boundary is defined that encompasses the elements that vary dynamically and those that are considered exogenously. The Case Study definitions comprise the following elements:

**The context and setting** – a qualitative description of the Case Study, in terms of the geography or system levels considered, users involved and energy services provided.

**The model boundary** – defines the variables and sub-systems optimised over and those features of the energy system that are exogenously defined.

**Exogenous variables of interest** – further features of the wider energy system that have an impact on multi vector value may be explored, to identify future system scenarios where the multi vector benefit is particularly significant or marginal.

**Global system parameters** – where variables are exogenous to the model boundary, we use a set of Global System Parameters which are used across a number of the case studies. These include price series, e.g. electricity and gas price series for relevant ESME scenarios, carbon price trajectories and so on.

**Timeframe** – a timeframe is also defined for each Case Study – this may be a particular year, e.g. 2030 or 2050 (most of the case studies are considered over at least a one-year period). In some cases, a longer timeframe is considered, e.g. the typical lifetime of a particular infrastructure.

The techno-economic analysis of the case studies is summarised in the following section. We then summarise the barriers to multi vector energy systems and identify some areas of innovation required to accelerate their deployment.

## 1.3 Summary of analysis of the cases:

### Case Study 1 – Electrification of heat with peak gas boilers

#### Case Study aims

Widespread electrification of heat coupled with decarbonisation of the electricity grid is a potential pathway to decarbonisation of space and water heating in buildings. However, the increase in peak electricity loads associated with thermal electrification is expected to necessitate very significant investment in grid reinforcement and increased generating capacity.

- The multi vector opportunity explored in this Case Study is retention of the gas network to meet peak heat loads while largely electrifying heat demand, using hybrid heat pumps.
- The multi vector case is compared to a single vector alternative of pure electric heat pumps with and without demand management.
- The study assesses the electricity network reinforcement investment required, and the fuel and emissions costs in both single and multi vector configurations, for various heat pump uptake scenarios.

#### Main features of modelling

- The modelling has been performed at the scale of a UK city, with Newcastle selected as the Case Study.
- The model considers component level reinforcement at the LV and HV tiers of the electricity network under a range of heat pump uptake scenarios, up to a maximum level consistent with the BEIS High scenario used in the Smart Grid Forum Work Stream 3[1] (around 70% penetration of heat pumps in the domestic sector by 2050).
- Parallel electrical load growth due to the deployment of electric vehicles is also included, following the BEIS Central scenario. Wholesale electricity, gas and carbon prices consistent with a high heat electrification scenario have been used, taken from ESME scenarios and BEIS projections.

#### Key findings

- In the highest heat pump uptake scenario, the multi vector configuration delivers a saving in grid reinforcement costs of around £3,000 per household, compared to unmanaged electrification of heat.
- This assumes smart management of hybrid heat pump operation to avoid substation overloads. While this is effective at reducing substation reinforcement costs, the model predicts that significant reinforcement of LV feeders will still be required. A more sophisticated management system, which allows monitoring of feeder loads, could potentially avoid all network reinforcement.
- While the peak loads that drive network reinforcement in the single vector case only occur for a limited number of hours in the year, the clustering of these periods in a winter cold spell means it is difficult to avoid peak electrical loads using thermal storage. The low CoP of heat pumps during the coldest periods exacerbates this problem.
- The multi vector configuration does not significantly undermine decarbonisation objectives – over 90% of thermal demand in hybrid heat pump homes are still met electrically. The additional fuel and carbon costs in the multi vector case are therefore found to be marginal and far outweighed by avoided network reinforcement.

[1] Assessing the impact of low carbon technologies on Great Britain's power distribution networks, Ofgem, 2012, ENA Work Stream 3

## Case Study 2 – Gas CHP and heat pumps supplying heat networks

### Case Study aims

In this Case Study we consider the following multi vector configuration: a gas-fired CHP system working in tandem with a heat pump to supply a district heating network. In this arrangement, the heat pump is powered by electricity generated by the CHP, while both the heat pump and the CHP engine provide heat to the district heating network.

We consider how the multi vector configuration is able to respond to electricity and gas price signals by varying the dispatch mode, to minimise overall costs of heat supply. For example at times of high electricity prices, the heat pump may be turned down and the cogeneration exported to the grid, while at low (or negative) electricity price periods, the heat pump may operate directly from grid electricity.

The multi vector configuration is compared to two single vector configurations:

i. a gas CHP based heat network
ii. a heat pump based system

With the total thermal output of primary plant equal across configurations. In all cases, we assume gas boilers are installed to supply peak heat demand.

### Main features of modelling

The Case Study model represents the energy system economically:

- Thermal demand profiles and building level annual totals are combined to calculate a bottom-up hourly district heating scheme demand profile, which we then diversify.
- The model then determines the lowest cost dispatch option to meet hourly thermal demands.
- The cost optimisation is run over a 25-year system lifetime, considering a range of carbon and fuel price scenarios.

### Key findings

- The multi vector configuration was found to reduce heat supply costs by around 3% compared to heat pump only supply, at social discount rates.
- At commercial discount rates, the higher up-front costs of the multi vector plant outweigh the lifetime operating cost savings compared to boiler only heat supply. This suggests some incentive or regulation might be required for commercial project developers to invest in significant multi vector plant.
- In the multi vector system, hybrid operation, i.e. the CHP powering the heat pump, is the lowest cost heat supply option for over 90% of the time at carbon prices below £90/tonne. As carbon prices increase, heat pump only operation becomes increasingly attractive (following BEIS projections, we assume the carbon intensity of grid electricity falls by a factor of 8 between 2020 and 2050 – from 0.255 to 0.032 tonnes $CO_2$/MWh).
- The multi vector system was not found to operate in CHP export mode for a significant fraction of the time. However, the system might potentially to provide local peak-shaving and ancillary services (this value is not assessed in detail).
- There do not appear to be significant engineering challenges associated with multi-heat supply, beyond those associated with hydraulic and thermal integration of multiple heat sources providing heat at different temperatures (care in plant sizing will also be required to ensure heat rejection is avoided). Operationally, the ability for the multi vector plant operator to optimise dispatch based on time-varying power prices will require different trading arrangements to those typically available to small (i.e. a few MW) scale plants.

### Case Study 3 – Supplying plug-in vehicle (PiV) demand with liquid fuels during periods of electricity supply constraint

#### Case Study aims

This Case Study considers a future scenario of widespread adoption of electrified transport and an electricity generating fleet that incorporates high levels of renewable generation capacity, much of it offshore wind. Such a system is vulnerable to capacity constraints during extended periods of low wind speeds, particularly when these periods coincide with peak electricity demand periods (i.e. peak winter). We determine the system level benefit of shifting the demand of a large fleet of plug-in hybrid electric vehicles off the electricity network, to rely on liquid fuels, during a prolonged period of constrained generation.

#### Main features of modelling

The model considers a two-week period of low wind speed in January 2050; we assume the total vehicle parc includes 8m hybrid electric vehicles – 7m cars and 1m vans.

The model assesses the total system electrical demand and generation, alongside the demand for liquid fuels. For the low wind speed period we then:

- Calculate the cost, by hour, of supplying hybrid vehicle energy demands though the power and the liquid fuel vectors.
- Identify periods of high power prices, where there is a system-level benefit in supplying energy through petrol and diesel, rather than electricity.
- Derive the total benefit of flexible supply by considering extended periods where the price of electrical supply exceeds that of liquid fuel supply, and calculating the total difference across such periods. This allows us to calculate the total savings achieved through fuel substitution.

Electricity prices are based on a 2050 high grid decarbonisation scenario and the oil price is scaled to BEIS gas price projections.

#### Key findings

- During the two-week low wind speed period in 2050, the modelled wholesale electrical price rises to a maximum of £330/MWh, around £440/MWh when peak time-of-use charges are included. This compares to a delivered liquid fuel cost of around £340/MWh.
- Only at times of extreme grid stress does liquid fuel supply to plug-in hybrid vehicles come at a lower system cost than marginal grid generating plant. These high price spikes tend to be of short duration, such that a single vector demand management strategy could provide an effective means of shifting PiV demand away from the highly constrained period. (Electricity supply costs rise above liquid fuel costs for a maximum period of 19 consecutive hours during the two-week low wind spell).
- Total annual value of flexible energy supply comprises less than £1 per vehicle per year; it is therefore unlikely to cover its up-front and incentivisation payments.

### Case Study 4 – Power to gas – transmission level RES to $H_2$ and RES to $CH_4$

#### Case Study aims

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 features of modelling

- The model considers the capacity of electrolysers that can economically be built assuming use of renewable generation oversupply, which is assumed to be available at zero cost.
- For this Case Study, it is assumed that the gas network can absorb all hydrogen produced (we consider the implications of this in terms of hydrogen blending limits under the GSMR and potential constraints on where on the gas grid $H_2$ injection can be accommodated in practice).
- A range of hydrogen prices are considered. A higher hydrogen price will allow the economic build of a larger capacity of electrolysers, given the same renewable oversupply duration curve.

### Key findings

- Power to hydrogen has been shown to reduce system costs compared to a 'do nothing' scenario of curtailment of renewable oversupply, however we find selective reinforcement of the transmission network – the single vector alternative – delivers greater overall system benefit under hydrogen and gas sale price parity at around £30/MWh.
- Despite the large amount of renewable generation on the system (up to 94GW), the duration curve of capacity curtailment leads to low annual capacity factors for the electrolysers, 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), appears still less economically attractive, due to its higher capital and operational fixed costs and further efficiency losses.
- A higher hydrogen price (up to £50/MWh is considered, consistent with the $H_2$ price in the Leeds H21 study) and reduced electrolyser capex assumption (we consider £701/ kW in the base case reducing to £526/kW in the low capex case) both have the effect of increasing the capacity of electrolysis that can be built and increase the system benefit delivered. A carbon price of £100/tonne $CO_2$ might result in hydrogen prices at these levels.
- In a scenario of both high $H_2$ price and reduced electrolyser cost, the power to $H_2$ system becomes competitive with selective transmission reinforcement as a means of dealing with renewables oversupply.
- Electrolysers could also provide a range of ancillary services to the electricity system, due to their flexibility and rapid response rates, potentially increasing the overall system value.

## Case Study 5 – Power to gas – Electrolytic $H_2$ production for dedicated $H_2$ networks

### Case Study aims

The potential for hydrogen to become the main vector of heating and cooking energy in the UK, by replacing natural gas in 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 Leeds H21 study focussed on steam methane reformation (SMR) with carbon capture and storage (CCS) as the principal means of generating hydrogen. 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 by grid electricity; electrolysis can support the matching of intra-day demand variation as it is more flexible than SMR due to its faster ramping rates, and may therefore partially replace the requirement for hydrogen storage

### Main features of modelling

- The model is based on a city of the scale of Leeds – with a heating demand of 6.4 TWh/year - 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 our base case the electricity price is £47/MWh (we do not consider a time varying price), while natural gas is costed at its ESME shadow price of £28/MWh.
- The model determines the least cost mix of SMR (with CCS[2]), diurnal and seasonal $H_2$ storage and grid powered electrolysis to meet the $H_2$ demand.
- Sensitivities to electrolyser capex, electricity prices and maximum dispatch rates of hydrogen storage have been assessed.

### Key findings

- Under base case electrolyser cost and fuel price assumptions, the whole $H_2$ demand is met by SMRs and storage, i.e. building electrolysers delivers no system benefit.
- Capex reduction alone does little to change this result, even at a 70% capex reduction the contribution of electrolysis to hydrogen supply is marginal (only 28MW of electrolysers are built, compared to around 1.25GW of SMR capacity).
- Electrolysis becomes more relevant under lower power prices; at £27/MWhe (a 45% reduction on the 2050 base case assumption) a significant capacity of electrolysers is built (>400 MW), delivering a total cost saving of 1.6% compared to the single vector case.
- When electrolysis is built, 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.
- As storage discharge times are increased, higher levels of electrolysis are built. This suggests there may be a role for electrolysis to provide some of the required flexibility if access to the appropriate geology for hydrogen storage is limited (e.g. if storage costs are higher or deliverability lower).

## Case Study 6 – Power to heat

### (a) Wind to district heating

### Case Study aims

This Case Study investigates the potential for district heating to mitigate constrained renewable generation on weak or isolated grids by connecting two independent systems:

1. A heat network supplied by a large heat pump, (with thermal storage used to avoid peak price power).
2. A wind farm facing curtailment due to connection to a constrained circuit (separated from the network to which the heat pump is connected).

The objective of the analysis is to understand the system benefit delivered by providing a connection between the wind farm and heat pump to reduce curtailment and the extent to which this justifies investment in the interconnecting cable, i.e. over what distance. The system benefit is compared against the single vector alternative of grid reinforcement and curtailment. We also explore whether varying the sizing of the heat pump and thermal storage affects the system benefit delivered in the multi vector case.

### Main features of modelling

- The heat pump and district heating system serves an average annual thermal demand of 50 GWh, with a peak hourly demand in a typical year of 16 MW.

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[2] Model results assume cost-effective CCS for SMR can be achieved (annualised CCS costs from ESME are around £42/tonne).

- A base case wind farm capacity of 15 MW is modelled, connected to a primary substation with a 5 MW transformer. The load on the substation is assumed to follow a typical demand profile for a primary substation of this size (typical of the demand of a small rural town).
- In the single vector case the model determines the cost optimal level of substation reinforcement and the optimal sizing and dispatch of heat pump and thermal storage on the DH system. In the multi vector configuration it determines these parameters and the optimal rating of the wind farm to heat pump interconnecting cable.

#### Key findings

- Curtailment is successfully reduced by exporting to the district heating system – 70% of curtailment is absorbed with total cost savings of around 6% of the combined costs of the two single vector systems.
- However, this cost saving justifies installing an interconnecting cable of the required capacity over a distance not greater than 900 metres (i.e. the savings only pay for the cost of the cable if the wind farm is no more than 900m from the heat pump).
- Increasing the size of the wind farm or increasing the heat demand on the DH network both lead to increased multi vector benefit. However, the system benefit is still only sufficient to pay for a few kilometres of cable, suggesting this solution will have only very limited applicability.
- While the system level benefit is marginal, the opportunity to avoid grid pass through costs by purchasing wind farm electricity over the private wire does create a significant benefit for the DH system operator, so there may be an attractive local business case for investing in the private wire.

### (b) Smart electric thermal storage (SETS)

#### Case Study aims

The second part of this Case Study considers a variant on power to heat, in which the output of renewable generation is balanced by a network of controllable domestic electric storage heaters. In this case, the flexible thermal demand is connected to the same network as the renewable generator (i.e. on the same side of the grid constraint as the generator).

The objective of the Case Study is to assess whether demand management of electric storage heating can increase the capacity of constrained power grids to connect renewable generation more cost-effectively that the single vector alternative of network reinforcement and curtailment. We also consider the potential for the distributed storage heating technology to be managed to provide further ancillary services and to lower the cost of low carbon heat supply.

#### Main features of modelling

- The analysis considers a range of different RES technologies – hydro, wind and solar – at varying scale, from 180 kW to 12MW. The study of different generator technologies enables the interaction of different diurnal and seasonal generation profiles with thermal demand to be assessed.
- The analysis considers both electric boilers with hot-water storage and smart electric storage heaters.
- Unmanaged and managed heating appliance control modes have been considered. In the former case, storage heaters are run at constant power during their off-peak hours (Economy 7 and 10 tariffs) and electric boilers are run to meet instantaneous demand, using local generation preferentially. In the managed case, appliances are run to absorb generation that would otherwise be curtailed, which is then stored.

#### Key findings

- Smart electric thermal storage has been shown to deliver a system value worth between £25 and £100 per user. Between 20 and 80% of this value is captured in the unmanaged case, i.e. simply by providing a source of demand on the same side of the constraint as the generator, with smart load control allowing a further £16 to £40 per year.

- This increases by around 25% to 35% when the environmental value of reduced curtailment is included (based on BEIS carbon price and grid average carbon intensity projections for 2020).
- This value is sufficient to justify the costs of monitoring and controls required to enable smart demand management for new build installations (estimated at around £20/year), although costs are expected to be significantly higher for retrofit of controls to existing storage heaters.
- The additional value accrues largely to the generator in this case, through reduced curtailment. A mechanism will be required to share this value with the customer (to incentivise their participation and potentially to reimburse additional electricity costs, where storage heaters are charged outside off-peak hours) and the aggregator that provides the demand response.

## Case Study 7 – Energy from waste flexing between CHP and gas grid injection

### Case Study aims

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, or 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 capability 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 and infrastructure.

### Main features of modelling

- Both anaerobic digestion (AD) and gasification plants are considered in this Case Study. We also consider two single vector configurations in each case:
    i. the AD plant and gasification plant produce biogas and bioSNG, respectively. These are burned in a CHP engine, which exports power to the grid.
    ii. The biogas and bio-SNG undergo further processing to upgrade the gases to grid-injection grade biomethane and bio-SNG. The biomethane / bioSNG are then injected to the gas grid via a grid entry unit.
- In the multi vector configurations, the plants can either burn the biogas/bioSNG in a CHP engine or methanate and clean-up the gas to inject into the GDN. The multi vector plant operator has the option 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.
- We consider each single vector option as a base case and assess the benefit in investing in additional plant to enable multi vector operation (i.e. either investing in a CHP engine or investing in further gas processing equipment and a grid entry unit).

### Key findings

- Based on the electricity and gas prices used in this analysis (generated using 2050 hourly gas and electricity price projections from the ESME High Renewables scenario with some probabilistic volatility layered in[3]), a benefit from adding multi vector capability was found in the case of AD for both single vector counterfactuals.
- In the case of gasification, there is a benefit in a CHP plant upgrading to enable gas injection, but not vice versa.

[3] The price fluctuations generated by this additional randomness was calibrated to historical levels of price volatility. 100 pairs of gas and electricity prices with this stochastic volatility were generated to be used in the multi vector dispatch model. The option value of flexing between electricity and gas prices was averaged across the 100 runs.

- Note that the results above assume no value is attached to the heat produced by the CHP (e.g. due to remoteness from thermal loads). A modest heat price can make the addition of CHP to a gas injection plant viable (and increase the benefit in the case of AD).
- The multi vector benefit increases as the price correlation between gas and electricity falls. Hence as gas and electricity prices become increasingly uncoupled there may be greater value in adding multi vector functionality, particularly – in the case of adding a CHP engine – where the heat can be sold.

  Overall, however, the scale of multi vector benefit identified in this Case Study is marginal.

## 1.4 Summary of Case Studies

The motivating questions for the analysis described above, the methodology and the key findings are summarised in the following table:

*Table 1 – Summary of Case Study Methodologies and Findings*

| Case Study | Focus of Investigation | Modelling/Methodology | Principal Findings |
|---|---|---|---|
| **1** | How much of the network reinforcement requirement associated with the electrification of heat might be avoided through hybrid gas/electric heat pumps? | We model the HV and LV network structure for the City of Newcastle, and investigate peak capacity demands at each grid component over the next 35 years, for a range of heat pump uptake scenarios and modes of operation.<br>In single vector scenarios, all heat pumps are pure electric units – in the multi vector they are hybrid units (in homes connected to the gas network).<br>For multi vector operation, we investigate a smart solution in which heat pump supply vector is determined by local grid capacity, and an unmonitored solution in which the electrical demand of hybrid HPs is set to some fraction of maximum household thermal demand, with peak heat supplied by gas. | The network reinforcement upgrade required by 2050 is worth £4,000 per household if 65% of homes are electrically heated, falling to £3,000 for 20% electrification. Most of this cost comprises LV feeder upgrade.<br>Depending on the sophistication of the control platform, multi vector heat supply might obviate between half and all this investment. These savings are two orders of magnitude greater than the annual cost associated with the additional carbon emissions.<br>Heat storage (in hot water tanks or more sophisticated solutions such as actively managed phase change materials) might allow heat pumps to move their electrical demand away from times of peak demand, our analysis however suggests that storage and DSM alone will not obviate the need for significant network reinforcement where heat is substantially electrified. |
| **2** | Can large heat pumps and gas CHP operate in tandem, and in reaction to movements in power and gas prices, | For a heat network with a given demand profile, we determine the costs of supplying heat through gas CHP, electric heat pump, | In a high carbon price future (driving significant district heating), there is a moderate cost reduction (between 2 and 4% of lifetime scheme costs) in supplying heat through a power cost responsive combination of gas CHP and water (or ground) source heat pump. |

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| | to reduce the supply costs for heat networks? | and a combination of these two options (with the cogeneration of a CHP used to power a heat pump). In the context of this study, the two former options are the "single vector" solutions (energy supply is not significantly impacted by hourly fuel costs) and the combined system is the multi vector solution (energy supply mode is determined by quarterly gas and hourly power price projections).<br><br>We consider variations in several key factors as sensitivities, including price volatility, the role of storage, and the export price of CHP cogeneration. | Further – given their similar demand patterns – separate heat pump and CHP powered networks represent natural candidates for "private wire", or other bespoke power delivery arrangements; the avoided network usage charges allow both to reduce their costs or increase their revenues relative to grid import/export arrangements respectively. |
| **3** | Is there value in a system which allows hybrid vehicle energy demand to be moved from the electrical to the liquid fuel system during times of depressed power generation (e.g. a low wind speed week in a high-renewable future)? | We use ESME[4] to determine the effect of low wind generation in 2050, and calculate the supply LCOE for unit petrol/diesel, comprising the fuel, distribution and environmental costs. We also calculate the levelised cost of power for marginal generation plant (OCGT) at a range of load factors.<br><br>The multi vector benefit then comprises the difference in the total energy cost between single vector supply (power) and the | We find the marginal cost of electric charging only rarely, and then fractionally, exceeds that of liquid fuel supply, and never for sufficient periods (greater than a day).<br><br>Given the flexibility of car and van charging, and their comparatively low average utilisation factors, any multi vector control system is likely to be of limited value. |

[4] The ETI whole energy system model, used throughout our analysis.

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| | | multi vector (cost responsive vector supply). | |
| **4** | Are power to hydrogen and power to methane with gas grid injection viable solutions as reservoirs for system level over generation in a high renewables future? | We investigate 2050 renewable oversupply and curtailment, and calculate its annual duration curve, given:<br>1. Scale and national distribution of renewable generation[5].<br>2. Future demand and transmission network capacity<br>We then determine in which cases this oversupply allows electrolysers to run at viable load factors (using oversupply/curtailment only, at zero fuel cost[6]).<br>The cost-optimal multi vector mitigation of oversupply is then compared single vector alternatives:<br>1. Curtailment (do nothing) | We find that in general, power-to-hydrogen (and particularly power-to-methane) struggle to compete with grid reinforcement as a solution to renewable overspill at hydrogen prices equivalent to per kWh gas prices (hydrogen for heat) of around £30/MWh. However, under an increase in the hydrogen price of around £20/MWh, due e.g. to environmental incentives, there may be viable opportunities for transmission network power to gas (though injection into the gas TNs turns out to be more problematic than into the GDNs; as the operators and OEMs of all connected plant (turbines, heavy industry, etc) must agree to higher hydrogen content levels. |

[5] These are calculated in ESME as a function of carbon price.

[6] We assume further than electrolysers can access all oversupply/curtailment without further grid reinforcement.

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| | | 2. Grid reinforcement<br>3. Battery storage<br><br>We consider the effect of a range of hydrogen prices and capital costs on the role for electrolysers, and qualitatively review potential revenues available through provision of grid regulation services. | |
| **5** | Under what future conditions might electrolysers have a significant role to play in supplying dedicated hydrogen networks? | We determine the 2050 LCOE of multi vector hydrogen supply (i.e. through electrolysis) and compare this to the cost of the primary single vector alternative – steam methane reforming (SMR).<br><br>Given that SMRs are most efficiently run at constant load factors, we consider also a role for electrolysis in meeting seasonal peaks in demand; here the single vector alternative comprises geological (e.g. salt cavern) hydrogen storage; as this is a new technology we | Under central projections of SMR (including CCS) and electrolyser capital and fuel costs (average power cost of £47/MWhe), we find the role for electrolysers is extremely limited.<br><br>We find that large capital cost reductions do little to change this situation, but at power costs below £30/MWh there may be a significant role for electrolysers.<br><br>We note that the cost projections for carbon capture and storage, for which there is no operational data, are central to this analysis. |

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| | | investigate a range of single vector costs and discharge capacities. | |
| **6a** | Can large scale heat pumps serving heat networks provide a reservoir for renewable oversupply; specifically, what degree of network investment is justified by the generation that can be absorbed in this way? | In the single vector scenario, we consider independently a heat network powered by a MW-scale heat pump, and nearby wind farm connected to a constrained circuit.<br><br>In the multi vector scenario, we allow the wind farm and DH energy centre to connect by means of a dedicated network, and compare the annualised cost of this connection to the value of the curtailment so avoided, which can be used to meet instantaneous heat demand, or stored as heat.<br><br>We also qualitatively review areas of the UK where there may be opportunities for the proximate development of heat networks and medium to- large scale renewables. Note we do not consider the potential revenues available to large heat pumps through grid regulation, which have proved necessary for | Our model returns the length of HV connection that can be justified given the increased wind farm utilization; for a 15MW windfarm and a 5MW heat pump around one kilometre of network is paid for by system savings/ While this result scales with increased generation size, there are expected to be few suitable locations in the UK.<br><br>However, taking the perspective of the wind farm and heat network operators, a private wire connection may allow them to share the avoided network usage charges; in this case the construction of around 10km of HV network may be justified.<br><br>Power-to-heat might therefore contribute to flexible load within the existing energy network, (the viability of heat pump powered networks will be driven by carbon prices, the cost distribution and carbon intensity of power, and falling plant capital costs) but is unlikely to drive substantial investment in the grid. |

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| | | power-to-heat scheme viability in Germany and Denmark. | |
| **6b** | To what extent does smart DSM of electric storage heaters allow greater utilization of renewable generators on constrained grids? | We model a renewable generator connected to an export limited constraint, and investigate the potential for a demand managed set of electric heaters (storage and immersion) – connected to the same grid branch as the generator – to mitigate curtailment. This multi vector solution – smart electric thermal storage (SETS) – allows power to be stored as heat in a distributed fashion.<br><br>To compare the single and multi vector alternatives, we then determine under what conditions the multi vector benefit (i.e. the value of the additional renewable utilisation) exceeds the per household control costs. | We find the per household control costs – around £20/device/year – are lower than the value of mitigated curtailment for a range of generator types: hydro, wind, and – to a lesser extent –solar.<br><br>Implementation and value sharing of the SETS platform may not be straightforward, as the commercial arrangements needed to allow the benefits sharing are uncertain and will need to be resolved. Current schemes are trials dedicated to increasing renewable uptake and energy access, run by Community Energy Scotland and utilities such as SSE.<br><br>Per kW load control costs are expected to remain higher for SETS (and domestic DSM generally) than for commercial loads, SETS is therefore likely to remain a grid management solution for isolated, LV DN branches. |

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| **7** | For what future energy system trajectories do energy from waste plants (anaerobic digesters and gasification plants) benefit from upgrading to allow them to export to both the power and gas networks as electricity prices vary diurnally and seasonally? | The single vector configurations comprise the single purpose AD and gasification plants (either CHP or grid injection facilities); the multi vector alternative then represents these plants upgraded to dual operation. To determine multi vector returns we use a Monte Carlo model of gas and power prices; multi vector plant operators can choose the higher value export option for each hourly timestep. | We find that both single vector AD plants may see benefit in including the multi vector option (either CHP or gas injection plant), and flexing operation according to power price movement, even where CHP heat is vented (as the majority of AD CHP heat currently is).<br><br>For gasification, unless CHP heat can be sold or used to offset plant expenditure (e.g. gas purchase for process heat) single vector injection facilities remain the most cost effective operational configuration. EfW plants can potentially be a good source of low cost heat for heat networks, provided they are not situated too remotely from sources of demand. Likewise, the heat network provides a useful revenue stream for the EfW plant, which could encourage a multi vector approach. |

## 1.5 Applicability and limitations

In the table below, we summarise the applicability and limitations of our models and the datasets on which they are based.

The analysis is based on predictions of the future, such as commodity prices, levels of demand, deployment of renewable generation and so on, in which there is inherent uncertainty. Where the multi vector solution has been shown to be of limited or marginal value, or where we must move some distance from our central projections to see an appreciable multi vector benefit, we discuss the robustness of the findings to alternative assumptions, e.g. different projections for price trends or technology learning rates, and discuss the conditions necessary for the multi vector system to deliver benefit to the future energy system.

*Table 2 – Summary of Case Study Methodologies and Findings*

| Case Study | Applicability / Uncertainties | Conditions for role in future energy system |
|---|---|---|
| 1 | **Hybrid heat pumps on constrained networks**<br><br>The finding that electrification of heat is associated with a significant network upgrade cost, and that multi vector heat supply mitigates most of this cost, holds under a range of uptake, demand management and network capacity assumptions. In particular, we find the network reinforcement costs comprise largely LV feeder upgrade requirement, these vary by less than a factor of 2 across suburban and rural areas, given lower population densities but reduced per km feeder replacement costs[7]. However, this conclusion is subject to the following caveats:<br><br>1. Heat pump DSM through storage appears to have some potential as a single vector means of mitigating the network upgrade required by electrification of heat. Whether sufficient power for heat can be delivered through an unreinforced distribution network in the coldest winter months (when heat pump coefficients of performance are not much better than 1) will depend on HP uptake levels, network headroom and growth and active management of other loads. Upgrade may also be required by regulation; specifying capacity design standards, e.g. for 1-in-20 projected peak winter demand.<br>2. This analysis does not present the full cost of electrification of heat, and cannot therefore be compared to alternative decarbonisation options such as biogas or | Multi vector supply appears to avoid most of the grid investment required by substantial electrification of heat to existing homes; the case is further bolstered by reduced user costs and generation infrastructure. Given the small volume of gas used, this case will not be undermined by very high gas and/or carbon prices.<br><br>What role hybrid heat pumps do play will therefore depend on the extent to which heat is electrified, which will be driven by future environmental policy, and the price of alternative means of low carbon heat supply; principally low carbon gas and district heat. The relative costs and benefits of multi vector supply may be slightly different on different gas and power distribution networks, and vary across urban and rural networks, though most of these factors are likely to be similar across the UK.<br><br>Operating a heat pump and gas boiler in tandem with UK legacy pipes and radiators in existing buildings is often not possible; this may be resolved through higher-T output heat pumps (e.g. those using transcritical $CO_2$ as a working fluid). |

[7] Cost data taken from the ETI Infrastructure cost calculator (ICC) dataset.

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| | hydrogen. Our analysis does not include the avoided investment in peak power plant, or the capital cost reduction associated with purchasing a smaller heat pump as part of a hybrid gas/electric heat supply solution; though both likely improve the consumer outlook for multi vector heat supply compared to single vector electrification.<br>3. We report the cost of the expected upgrade today (based on ICC 2015 prices). Deferral or incremental roll out of this investment will lead to slightly different costs (the ICC data project increases of around 3% above inflation every five years for grid component upgrades). | |
| 2 | **Multi vector heat generation for district heating**<br>The finding that multi vector heat supply marginally lowers lifetime DH costs seem robust under a range of fuel and carbon price projections, and power supply arrangements, we note however that:<br>1. We have not considered thermal operation of HP and CHP in series (in which water is heated to an intermediate temperature in a HP first, and then further heated using CHP heat), which would allow heat pumps in multi vector networks to operate at higher CoP s.<br>2. In our analysis gas combustion becomes increasingly expensive as carbon prices rise. Lower carbon gas supplies, such as biofuels or hydrogen, may mitigate the carbon cost of running boilers and CHP engines; this has not been considered in our analysis.<br>3. Heat pumps have been considered as a means of low temperature waste heat recovery; such units could be combined with a gas CHP; as they would run at higher CoP s, this would reduce the relative size of the CHP. | A multi vector heat network allows for, and may de-risk, phased development of a heat network.<br>Initially gas CHP may provide the most proven and cost-effective plant option for DH development, however the carbon emissions performance will diminish over the plant lifetime as the electricity grid decarbonises. Adding a heat pump, powered by the CHP improves the CO2 performance of the system and could provide opportunities to optimise plant dispatch in response to gas and electricity price variations. At the end of the CHP's lifecycle, when carbon prices are higher, it could be replaced with a second heat pump (assuming the carbon price at this point means that it is no longer economic to run a gas CHP). |
| 3 | **PiV switching to liquid fuel at times of generation capacity shortage**<br>We have attempted, without success, to find plausible scenarios in which the cost of liquid fuel supply undercuts that of electricity. We note further that:<br>1. Our analysis does not consider the cost of air quality, this clearly further disincentivizes switching to liquid fuels.<br>2. We have calculated the LCOE of power and liquid fuel supply (including carbon cost); and find that supplying the vehicle energy to drive unit distance is cheaper using power from gas than as petrol/diesel. For this not to hold, the oil-to-gas price ratio would have to fall to historically unprecedented levels.<br>3. Additional use of liquid fuels also leads to increases in particulate matter and NOx emissions, which further undermines the case for this multi vector solution. | This analysis suggests that the conditions necessary for this case to deliver material benefit are highly unlikely.<br>For liquid fuels to be preferred to electric supply for PiVs, power prices would need to exceed £400/MWh for an unbroken period of several days. Were such prices possible, developers would likely build peaking thermal plant; even at low load factors this would be a cheaper and cleaner solution |

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| 4 | **Power-to-$H_2$/$CH_4$ from renewable oversupply**<br><br>In our model, we assume all curtailment/oversupply can be delivered at zero cost to electrolysers without investment in the power grid; given we find little multi vector benefit under this optimistic assumption it is unlikely that power-to-gas based on renewables oversupply will make a material contribution in the future energy system. However, we note that:<br><br>1. Further study will be required to assess smaller scale applications for electrolysers, and more valuable hydrogen supply opportunities - our analysis does not consider the value of hydrogen for transport (i.e. on a kWh alternative to taxed diesel to petrol).<br>2. The ESME duration curve is blocky, so that incremental changes in model parameters produce no change in outputs. As such, the exact model outputs have been read qualitatively, rather than as precise projections of future total electrolyser capacity | Power to gas might be viable at hydrogen prices of around £50/MWh, around 60% above future gas price projections. Therefore, power-to-gas would need to be supported by an environmental credit worth around £100 - £150/tonne $CO_2$, (assuming all oversupply is zero-carbon).<br><br>We note that the efficiency and capital cost numbers used in our analysis (80% and £701/kW) are, respectively, significantly above and below current operational values, and will require significant technological and engineering progress. This progress will likely depend on substantial use of hydrogen as an energy supply vector in the period between 2020 and 2050. |
| 5 | **Grid-powered Electrolysis for hydrogen gas grids**<br><br>We assess the role for electrolysers to supply hydrogen for heat to a network based on the H21 Project Leeds area[8], both to supply baseline demand and as a means of peak matching – reducing the size of the SMRs required, or obviating the need for dedicated storage.<br><br>In our central scenario the single vector appears to outperform the multi vector by some margin (this agrees with the H21 assessment). However:<br><br>1. There is little good data for the single vector alternative – SMR with CCS; a role in hydrogen supply for electrolysers cannot be ruled out without better assessments of the costs of, and UK capacity for, SMR and CCS.<br>2. Our analysis does not consider a distribution of power prices; rather all electricity is purchased at the annual average price of £47/MWh. Electrolysers may be able to operate more profitably running preferentially at lower power prices (away from peak times). | Aggressive capital cost reductions have relatively little effect on viable electrolyser capacity, though this implies that scheme viability is not significantly affected by capital costs, so electrolysers can profitably operate at relatively low load factors, and fuel (power) prices dominate the analysis.<br><br>At power prices below £30/MWh electrolysers are expected supply over a third of total hydrogen demand – these power costs are around 40% below our central prediction. Even at these generation costs, electrolysers would likely have to minimise grid use charges, perhaps by connecting to the NTS, which will have implications for project scale.<br><br>The model efficiency values of 80% are expected to be achievable with solid oxide electrolysers; real life values would need to be at least this good for electrolysis to viably supply hydrogen for heat. |
| 6a | **Power-to-heat for district heating**<br><br>We review a range of capital costs, degrees of oversupply/curtailment, and find that the value of flexible load provided by heat pump powered heat networks justifies investment | As in Case Study 4; we find that as curtailed power is distributed with a "peaky" duration curve, and the value of the commodity produced through its capture (heat, or in CS4, hydrogen for gas |

[8] We model a demand of 6.4TWh $H_2$ annually, and include a peak supply requirement of 3,180MW.

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| | of around one kilometre of private HV network, and up to ten kilometres if we price in the avoided network use costs. Further parallel analysis of the national distribution of wind and solar resource, and the areas favourable to heat network development (e.g. urban areas) will be needed to assess national opportunities to upgrade the grid to encourage power-to-heat, though our findings suggest it will be marginal. | network injection) is relatively low, we cannot justify significant outlay in infrastructure (HV network or electrolyser) to utilise this curtailed power. Whereas the price of hydrogen rises if supplied to other markets, for example as a vehicle fuel, it is not clear that there are comparable opportunities to raise the price of heat. |
| 6b | **Smart electric thermal storage**<br>We review a range of generator types and relative sizes of generation and thermal demand, and find that the annual value of SETS exceeds its annual control costs by between 10% and 200%, and the single vector mitigation options – dedicated battery storage and network upgrade – are several times more expensive. We note further that:<br>1. The control system costs to which they are compared are taken from an Element Study[107] Manufacturers aim to offer aggregator ready storage heaters by Q3 of 2017 at lower control costs.<br>2. To estimate the potential national scale of SETS, a geographical analysis of the location of the 15% of UK electrically heated homes and connection limited networks is required. Such an analysis would need to consider the costs of alternative sources of ANM, e.g. flexible commercial load, on LV networks where substantial electrified heat is connected (particularly, away from the gas networks).<br>3. SETS uses necessary infrastructure to manage grid loads; in the medium-to-long term EVs could compete with SETS to provide this service (and further vehicle to grid services), though EV energy demand totals are lower than for heat, particularly in winter. | Suppliers are investigating storage heaters as a source of flexible load across Europe, e.g. the SSE Real Value Project.<br>Glen Dimplex will bring an “aggregator ready” storage heater to market in Q3 2017, whether aggregators look to use these as a source of flexible load, remains to be seen. Commercial arrangements to share SETS value between customers, suppliers and generators remain the primary sticking point for implementation of SETS and similar schemes. Service providers such as home energy control firms aim to offer load management to customers on a zero up-front cost and reduced fuel bill basis. |
| 7 | **Multi vector energy from waste**<br>We have shown that energy from waste plants may see benefit in upgrading to multi vector operation, particularly where CHP heat can be sold, rather than vented. We note<br>1. We have not considered a customer for heat in our analysis; the value of heat has been considered as a margin on top of the power price. This means that the relative movement of heat demand and power & gas prices has not been fully explored.<br>2. The effect of carbon prices is not considered in this analysis; a high carbon price will encourage biogas to be injected into the grid, rather than burned in a low electrical efficiency CHP for power-only export. However, if some CHP heat can be used to displace gas use, the heat price may include environmental value making multi vector operation most viable. | Our consultation in the gas and EfW sectors finds the industry view is that as there are greater opportunities to decarbonise gas than power, AD and gasification should focus on generating green gas, rather than power and/or heat. Our analysis suggests however that a hybrid role CHP/grid injection may be most profitable for EfW facility development once the technology is mature and subsidy free. |

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| | 3. Plant sizes are fixed; we investigate a 20MW facility and while CHP engine prices scale with plant size (at £490,000/MWe), grid injection capital costs are fixed at £700,000. | |

## 1.6 Barriers and innovation opportunities

A range of specific barriers and potential innovation options have been identified for each of the case studies, following extensive consultation with key stakeholders. These barriers, which include technical, regulatory, commercial and consumer issues, are discussed in detail in the WP5 report *D5.1 Barriers to Multi Vector Integration*.

Looking across the multi vector case studies investigated in detail in the study, we have identified six areas that the key barriers to closer multi vector integration fall within and where innovation actions will be required. These six key areas are tabulated below together with the multi vector systems explore in the case studies that are most strongly affected.

*Table 3 – Barriers to a Multi Vector Energy System and Affected Case Studies*

| Barrier | Multi Vector Case Studies Affected |
|---|---|
| Distribution Network Telemetry | 1. Hybrid heat pumps[9]<br>6b. Domestic turn up and thermal store (SETS) |
| Domestic Demand Response Platform | 1. Hybrid heat pumps[9]<br>2. CHP and HP in heat networks<br>6b. Domestic turn up and thermal store (SETS) |
| Need for Clarity in Low Carbon Heat Policy | 1. Hybrid heat pumps[9]<br>2. CHP and HP in heat networks<br>7. Flexible CHP/Grid injecting EfW plants |
| Gas Network Charging | 1. Hybrid heat pumps |
| Future of Hydrogen | 4. P2G- injection into NTS<br>5. P2G into dedicated hydrogen network |
| Increased Coordination | All Cases Studies |

The nature of the barriers in these six key areas and the innovation needs that have been identified are described in further detail in the table below.

[9] Multi vector heat supply might also mitigate network loads by under sizing heat pumps and supplying peak demand using gas; this would not require sophisticated network telemetry or a DR platform, but does depend on policy to maintain gas connections and boilers at heat pump equipped homes.

| Barrier / innovation area | Description | Innovation Requirement |
|---|---|---|
| **Distribution Network Telemetry** | • As shown in Case Study 1, the benefit from multi vector heating with demand management is maximised where loads on LV assets (feeders and distribution substations) can be managed.<br>• However, currently there is little monitoring of the LV network, due to the high costs associated with the large number of LV assets and the historic lack of business case for investing in LV network monitoring.<br>• The lack of visibility of the LV network is a barrier to the temporally and spatially resolved demand management strategies needed to minimise investment at the LV level. | • **Development of low cost monitoring and communications** to provide more granular data on LV voltages and load flows<br>• As an alternative to monitoring hardware, **investigate use of Smart Meter Data to develop stochastic models of network loads** (incorporating also weather data, demographics etc.) |
| **Domestic Demand Response Platform** | • Demand-side response in the domestic sector is key to the multi vector heating strategy in Case Study 1 and smart power-to-heat in Case Study 6b.<br>• Recent innovation projects have trialled a variety of methods to achieve firm demand side response (DSR) from the domestic sector, including pricing signals (static and dynamic) and direct load control.<br>• Further trials are required to identify the most cost-effective means of securing reliable DSR in the domestic sector.<br>• Demand management of multi vector heating technologies could result in loss of diversity, with potential implications for ramp rates on the gas and electricity networks. Control strategies are required that manage the rate of load increase on low pressure / low voltage networks. | • **Flexible low carbon heating trials** – comparative trial of multi vector heating technologies (hybrid heat pumps, pure electric heat pumps with thermal storage and micro-CHP) to assess demand response capabilities.<br>• **Control systems and DSR mechanisms** – assessment of various control technologies and DSR strategies (pricing based and load control), potentially as part of the above technology trial. |
| **Need for Clarity in Low Carbon Heat Policy** | • There are a range of options for decarbonisation of the heat sector, including electrification, hybrid heat pumps, heat networks and conversion of gas networks to hydrogen. Several of these pathways are likely to involve closer multi vector interaction. | • **Low carbon heating trials** – Trials of multi vector technologies (as above) to assess role in heat decarbonisation (in different segments of the building stock), alongside government and Network Innovation Stimulus trials of hydrogen for heat. |

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| | • These heat decarbonisation pathways have very different infrastructure requirements and are likely to require significant changes to network regulation and energy market design.<br>• Clarity in low carbon heat policy, which sets out a clear strategic direction is likely to be crucial for the networks and other stakeholders (e.g. heating appliance manufacturers) to have the confidence to make the necessary investments in infrastructure, product design etc. | • Ensure research into multi vector energy systems, including technology trials, modelling and development of appropriate market and regulatory frameworks, is adequately funded. The Network Innovation Stimulus may be the most appropriate mechanism, but there is a need to ensure that the value of cross-vector projects (e.g. joint electricity and gas proposals) is recognised in the evaluation process. |
| **Gas Network Charging** | • The pathway to low carbon heating has significant implications for the future of the gas network – possible outcomes include decommissioning, continued use as a peak supply vector and re-purposing to supply hydrogen.<br>• In the multi vector heating case described in Case Study 1, the gas distribution network needs to be maintained but at significantly reduced throughput. Gas network depreciation costs and a large part of the opex costs will remain despite the lower throughput, hence use of system costs will become a much larger component of the per unit price of gas. This has potential to create an unequal distribution of gas network costs between multi vector users and customers that retain the gas network as their primary heating fuel.<br>• A revised charging model is likely to be required in this case. This could weight network cost recovery more heavily toward capacity charges, rather than commodity charges. Some form of socialisation of gas network charges might also be considered, to ensure energy costs are affordable for persistence gas and multi vector users. | • **Assessment of gas network cost recovery model** – development and modelling of new regulatory models for the gas networks as part of multi vector energy systems (particularly the case of gas as a peak heat supply vector).<br>• **Sharing multi vector system benefits across network companies and customers** – ensure that network companies are properly incentivised through the regulatory model to engage in cross-vector coordination where beneficial (even where that benefit accrues to another network). |
| **Future of Hydrogen** | • The future role of hydrogen is a further key uncertainty in the decarbonisation pathway for the heat sector. A significant programme of work on this is currently being planned by government and network companies, stimulated by the Leeds H21 project. | • **Extensive programme of research into hydrogen in the gas network** – substantial R&D and field trial activity is required to prove the feasibility and cost-effectiveness of hydrogen as a heating fuel, supplied by the gas network. This programme of work is |

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| | • From a multi vector perspective, we have considered power-to-hydrogen for injection into the gas grid and as a production option for dedicated hydrogen networks. The economic case for both these configurations has been shown to be challenging. The role of electrolysers is likely to depend on significant capital cost reductions being achieved, availability of low cost electricity and a higher $H_2$ price than the energy equivalent natural gas price. The business case for electrolysers may also be dependent on the additional revenues that can be generated by provision of services to the electricity system, e.g. balancing, demand turn-up and frequency response.<br>• Gas network re-purposing to carry hydrogen is generally considered 10 to 15 years away, assuming it can be shown to be technically feasible and affordable. The nearer term potential for power-to-$H_2$ is therefore highly dependent on changes to the Gas Safety (Management) Regulations (GS(M)R), to permit higher concentrations of hydrogen in the gas network (currently limited to 0.1% by volume).<br>• Hydrogen as a transport fuel is in the early stages of deployments both in light duty (cars and vans), and heavy-duty fleet, vehicles (trucks and buses). An early UK network of around 20 hydrogen refuelling stations is being deployed under several EU-funded projects, coordinating between vehicle suppliers, station operators and government departments. Deployment volumes are expected in the low hundreds of vehicles before 2020, with significant increases after that date following the introduction of lower cost, second generation vehicles.<br>In heavy vehicles, several UK cities (London, Birmingham, Aberdeen and Dundee) are participating in the EU-funded JIVE fuel cell bus project, and are in the process of jointly procuring tens of fuel cell buses for introduction in the next 2 years. | already being developed by government and network companies.<br>• Role and business case for power-to-$H_2$ via electrolysis – building on projects such as the Aberdeen Hydrogen Project (Scottish & Southern Energy Networks), further trials to assess the business case for electrolysers in power-to-heat applications. Particularly the ability of electrolysers to provide services to the electricity system (to network companies, suppliers and ancillary services) and the impact on the economics of power to $H_2$. |

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| **Increased Coordination** | • Identification and operation of multi vector opportunities will require significantly greater cooperation between network operators than is currently the case.<br>• Currently the electricity and gas network operators develop investment plans for their network areas based on their own projections of demand and connection of generation / sources, with no formal cooperation. Identification of multi vector opportunities that could provide a more cost-effective means of meeting energy requirements will necessitate some coordination in plan-making, ranging from demonstrating that multi vector solutions have been considered to development of joint investment plans. The regulator will need to consider how such coordination is managed, to ensure that network companies are incentivised to exploit multi vector opportunities that may be more cost-effective overall, but that might result in e.g. a reduced growth of their own asset base.<br>• A number of the multi vector opportunities we have considered involve flexing demand or generation between networks on short-term timescales, e.g. driven by energy market price fluctuations. The data-sharing required between network operators and the mechanism of this data exchange, potentially in real-time, will need to be understood and secure systems put in place. | • Joint investment planning across networks<br>• Increased role for local authorities in planning local energy network development<br>• Review of network regulation |

# 2 Introduction

## 2.1 Study Motivation

This study aims to understand the opportunity for, and implications of, moving to more integrated, multi vector networks. Our analysis reviews multi vector solutions to several future energy system challenges, and strategic and technical innovation required to enable multi vector supply.

## 2.2 Case Studies

This report summarises the detailed the work undertaken in the project to date, which includes:

- Creation of a Long List of Case Studies
- Filtering these, in coordination with the Steering Group, to create a Short List
- Technical analysis and economic modelling of these cases
- Interpretation of model results
- Discussion of the engineering, operational, commercial and regulatory hurdles to a transition to a multi vector energy system, and associated innovation requirements.

### 2.2.1 Case Study Long List

In Tasks 1 and 2, Case Studies were identified and then defined in detail. A full list of Case Studies presented at the first project meeting can be found in appendix 10.

### 2.2.2 Filtering

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

Based on this filtering process, the following short list of cases was selected for detailed analysis:

1. Domestic 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 Techno-economic Modelling

Each of the Case Study models 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. These 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.

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 one or more 'good' single vector case(s).

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

Our Case Study analysis is discussed in section 2.

## 2.4 Barriers, Opportunities and Areas for Innovation

The engineering, operational, commercial and regulatory barriers to operating in the multi vector configuration are assessed in the accompanying report *D5.1 Barriers to Multi Vector Energy Supply;* a summary of those findings is presented in section 3.

# 3 Case Study Analysis

## 3.1 Case 1: Domestic Heat Pumps and Peak Gas Boilers

### 3.1.1 Introduction

#### Context

How to decarbonise UK domestic heating, over 85%[10] 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.

[10] 2016 ECUK Data

### 3.1.2 Data and Analysis

The modelling of this Case Study is based on the City of Newcastle[11]; selected as:

i. Grid topology models built for the ETIs' EnergyPath Networks (EPN) project[12] 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.

#### Overview of Model Operation

The Case Study model calculates the peak load at each component in Newcastle's electrical network under increasing thermal electrification, given the single and multi vector heat supply alternatives above. For a range of years to 2050, we calculate:

i. The hourly appliance use and EV charging load at each building.
ii. The thermal demand, and the share of this demand met by resistance heaters and heat pumps in each of the four above supply modes.
iii. The corresponding total building level electrical demand.
iv. The resultant demand on each grid component (the network comprises LV and HV feeders[13] and substations).

This allows us to determine which, if any, network components are overloaded for that hour, and by aggregating these datasets for the entire year we can determine the total network reinforcement requirement, and therefore the total upgrade cost.

A summary of the model assumptions and parameters is shown below.

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

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

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

*Table 4 – Summary of Model Data Sources and Assumptions*

| Model Parameter | Source / Description |
|---|---|
| Power Prices | Calculated in PLEXOS from the high thermal electrification ESME Decarbonisation Scenario. |
| Gas Prices | A value of £30/MWh is taken from BEIS projections. |
| Carbon Prices | A carbon price of £200/tonne is used throughout this analysis, to:<br>• Reflect a future in which electrification of heat is strongly incentivised<br>• Discourage gas combustion, even at times of low heat pump CoP. |
| Network Topology | Taken from EPN model; a nearest neighbour algorithm matches LV and HV users and substations, connection length is determined by road layout. |
| Demographic Data | Taken from EPN data, New build rate of 1%, demolition rate of 0.5%. |
| Total Energy Demand | Domestic data taken from SAP, commercial demands taken from CIBSE area benchmarks and VOA floor area data. Both are calibrated against ECUK data. |
| Energy Demand Profiles | Hourly electrical appliance demand is given by upstream primary substation load profiles. |
| CoP Data | Domestic buildings use ASHPs, with CoPs ranging between 1.1 at below 0°C and 4.2 at above 15°C. I&C users have a fixed CoP of 3.0 |
| Heat Pump Uptake | Model input totals are shared across the building stock based on their likelihood to upgrade, based on thermal efficiency, existing plant and the socio-economic demographic data. |

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:

*Table 5 – 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 Multi Vector Benefit

In this section, we present, for the four heat supply solutions:

- the network upgrade costs, and
- the environmental and fuel costs associated with multi vector heat supply.

#### Grid Reinforcement Costs

Reinforcement costs by scenario are shown below.

*Table 6 – Summary of Scenario Upgrade Costs*

| Scenario | HV System Costs (£m and number) | | LV System Costs (£m and number) | | Total Cost |
|---|---|---|---|---|---|
| | 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** |

Total 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.

- **Installation of heat pumps in 65% of domestic buildings by 2050 creates a liability of between £250m and £400m, (£2,800 and £4,400 per household[14] respectively). These figures represent lower and upper bounds on grid reinforcement associated with the unmonitored electrified supply of heat.**

[14] Throughout this analysis, per household figures refer to the number of households in which heat pumps are installed but gas was previously used, of which there are around 90,000 by 2050.

- **Multi vector heat supply avoids between £115 million and the entire network upgrade cost - between £1,250 and £4,400 per household. This is substantially more than the lifetime cost of installing and/or maintaining a (top-up) boiler, though the Smart multi vector solution implementation will require a sophisticated control system, the costs of which are discussed in the next section.**
- **At a network upgrade cost of only £32m more than the smart alternative, unmanaged multi vector heat supply may be the most cost-effective grid management option, particularly if:**
  - **Smart control costs are high, i.e. the intelligent control system is expensive, and**
  - **Small heat pumps are significantly cheaper than large ones, e.g. if prices comprise largely marginal unit, rather than installation, costs.**
- **However, in each scenario feeder upgrade costs – particularly LV feeders - dominate other upgrade costs. In the smart multi vector configuration, all the grid upgrade costs – over £110m – are associated with feeder replacements. A system which monitored loads at feeders (as well as substations) and managed multi vector heat supply technologies to avoid breaching feeder operating limits (mainly thermal constraints), could potentially avoid all grid upgrade costs. The system benefit of demand managed multi vector supply would then increase by £115m - from £300 to £1,250 per household – though a more sophisticated monitoring and control system would be required.**
- **Although how best to implement multi vector heat supply will depend on many factors, smart management and undersizing heat pumps are not mutually exclusive, and a hybrid solution (a small, DSM-ready hybrid heat pump) may offer the most cost-effective means of electrifying heat, depending on relative control system, OEM, fuel and carbon prices.**
- **Although quantitative assessment of implications for generation are outside the scope of this study, there are likely to be significant national level benefits to electrical generators associated with the demand manageability of over half of total UK thermal demand.**

### Running Costs

Multi vector fuel switching may undo the environmental benefit of the electrification of heat, if the use of gas is too great. We find however that the peak demand supplied by gas comprises less than 10% of total demand and that the environmental costs of multi vector supply are low, even at very high carbon prices

- **City wide, multi vector heat supply avoids two orders of magnitude more in network reinforcement than it incurs in annual emissions cost. Indeed, there may be no difference in annual running costs; the O&M of the additional substation capacity and feeders required for secure single vector heat pump supply, are likely to offset the small environmental benefit of pure electric heating.**

*Table 7 –Total Annual Heating Fuel Demand, Emissions and Associated Costs across Newcastle*

| Scenario | Total Electrical Demand (GWh) | Electricity 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** | 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** |

## Sensitivity Analysis

Our modelling assumes:

i. That all grid components have a minimum 25% headroom above their 2016 peak, and can use the entirety of this to accommodate heat pump demand[15].
ii. That 100,000 homes (65% of the total Newcastle stock) install heat pumps by 2050.

Below, we show the results where:

i. No minimum headroom is included, (i.e. grid components are sized to the smallest size larger than their 2016 peak demand). This might reflect either a grid which is currently operating at capacity, or a requirement to maintain some headroom on the network.
ii. Under a range of lower heat pump uptake totals.

*Table 8 – Sensitivity– Network Upgrade Costs (£m) for a range of total Newcastle 2050 HP Uptake*

| Scenario | Reduced Headroom | Total Heat Pump Uptake | | | | | |
|---|---|---|---|---|---|---|---|
| | | 30,000 | 45,000 | 60,000 | 75,000 | 90,000 | 100,000 |
| **High Electrification** | 574.3 | 90.64 | 123.57 | 180.38 | 254.17 | 323.39 | 393.40 |
| **Smart Multi Vector** | 156.0 | 31.99 | 40.61 | 65.13 | 83.70 | 99.91 | 113.40 |
| *Saving per Multi Vector Household* | *£4,650* | *£2,170* | *£2,050* | *£2,130* | *£2,530* | *£2,760* | *£3,110* |

[15] As well as determining the network capacity to accommodate peak expansion, this is also the principal determinant of whether sufficient heat can be generated and stored off-peak in a single vector solution.

- **Smart multi vector supply savings increase over the unmanaged single vector alternative as network headroom decreases:**
  - **From around £250m (£2,000 per household) at a minimum of 25% headroom.**
  - **To as much as £400m (£4,400 per household) at no minimum headroom.**

  **Multi vector benefit is not reduced by lack of network headroom or more stringent operational requirements.**

  **We found also that reduction in network headroom increases the value of the smart over the unmanaged multi vector solution – from £25m (£300 per household) to over £100m (£125 per household), comprising avoided substation reinforcement.**
- **Smart multi vector heat supply saves over £2,000 per household under substantial electrification of heat; as uptake levels rise from 20% and 65%, this saving increases by around half. Given control system fixed costs, there may be some minimum required level of take up to incentivise a smart multi vector solution.**
- **We found that while EV demand, particularly for fast DC chargers, may present operational and infrastructure challenges to DNOs, these concerns can be largely uncoupled from the network capacity challenge associated with electrifying heat, for analysis see the report *D3.1 Assessment of Local Cases*.**

## Applicability

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

*Table 9 – Applicability of Case Study Analysis*

| Parameter | Wider Relevance |
|---|---|
| Network Structure | **Our findings are likely to be applicable to most UK areas.**<br>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 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. |
| Security of Supply | **Resilience requirements for highly electrified singly vector heat supply may increase network upgrade costs, and therefore multi vector benefit.**<br>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. 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. |
| Real World Heat Pump Performance | **Model CoP Values are unlikely to overestimate heat pump performance at times of peak grid load.**<br>Model CoP values are unadjusted from manufacturer literature. Field trial data suggests heat pump performance may operate at lower CoPs, due to installation or operational issues. However:<br>• 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.<br>• Technology improvements – 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.<br>• Peak grid demand is driven by heat pump uptake, so thermoelectric demand increases until after 2040, by which time heat pump operational performance is expected to meet or exceed 2015 manufacturer data. |
| I&C Heat Pump Use | **It is unlikely that the industrial and commercial profile leads to a significant overestimate in grid reinforcement costs.**<br>Due to the lack of high quality data, model commercial and industrial thermal demand follows the domestic profile; which 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:<br>• Given the constant year-round CoP of water and ground source heat pumps, the I&C contribution to the winter peak is only around 3% of total heat pump demand.<br>• Around a third of this demand is connected to the HV grid, where reinforcement costs are lower. |
| Population Density | **Grid reinforcement costs and savings should be broadly similar in rural and urban areas.**<br>LV Feeder replacement costs dominate all grid upgrade totals. In sparsely populated areas:<br>i. material costs of LV feeders may be larger, given the longer networks, but<br>ii. installation may be cheaper, given that overhead lines can typically be used.<br>Rough unit connection costs, taken from the ETI Infrastructure Cost Calculator[16] scalars, and by-area housing density classification from the Committee on Climate Change research on District Heating and Local Approaches to Heat Decarbonisation[17], suggest that electricity network upgrade costs per dwelling vary by less than a factor of two across rural, sub-urban and urban areas. |

[16] ETI Infrastructure Cost Calculator

[17] District Heating and Localised Approaches to Decarbonisation, Committee on Climate Change, 2015

### 3.1.4 Multi Vector Implementation

This section explores the implementation options and control system requirements for multi vector heat supply.

#### Demand Management of Heating – Platform Requirements

Under smart multi vector supply, gas use is determined by the headroom on the LV and upstream HV substations. Even where headroom is limited – not much greater than 25% above 2016 demand peaks – gas use is confined to periods of up to a few consecutive hours in winter months, with:

i. Some thermal demand supplied by gas for around 1,000 hours in the year
ii. 92% of city-wide multi vector households'[18] thermal demand met electrically

We find that heat pump driven load increase is not uniformly distributed across substations; some require substantial upgrade, while others see little increase in peak demand.

Also, while we model the electrification of 65% of homes by 2050, those substations which require upgrade do so before 2035 (by which time only around 30% of homes are electrified), due to clustering of heat pump uptake. Realising the full Multi Vector savings modelled above through demand management therefore requires that heat demand can be moved from the electrical to the gas vectors on an hourly resolution within the next 20 years. (Monthly use data, heat supply profiles for a week in January 2040, and the distribution of load growth across the HV substations are shown in appendix 7.1.2).

- **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. Realising the full multi vector value demands 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 20 years (this point is discussed further in the section on Barriers and Innovation Requirements).**

#### Smart Storage as a Single Vector Alternative to Gas Use

Given a smart thermal demand management platform, grid load might be managed by generating and storing heat during off peak hours and dispatching this heat to meet peak demand; shifting electrical heating demand off the system. Our analysis suggests the role for storage will depend on network headroom and off-peak demand levels; hot water storage can reduce gas use in combination with multi vector heating, but cannot in general obviate the need for an alternative heat supply vector under high heat pump uptake. High density thermal storage technologies, such as phase change materials (PCMs) or building thermal efficiency improvements may increase the potential for storage, see appendix 7.1.1.

- **Intelligent use of hot water tanks does not represent a universal solution to managing peak electrical demand management; though it may constitute a lower cost alternative to multi vector heating in some areas, 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 grid 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.**

[18] Those buildings with heat pumps installed that are also connected to the gas network

## Multi Vector Supply through Limited Heat Pump Size

An alternative, less control intensive means of mitigating the grid impact of large scale heat pump uptake is to limit the size of the heat pumps (specifically, their maximum current draw) and to use gas as a peak supply vector. Due to the sharply peaked nature of the duration curve of annual thermal demand, a heat pump sized to 50% of the maximum electrical meets over 90% of thermal demands; the relationship between heat pump size and the fraction of heat supplied electrically is shown below.

*Table 10 – Heat Pump Sizing and Associated Electrical Supply Fraction*

| Heat Pump Peak Size Fraction | Electrical Supply Fraction[19] |
|---|---|
| 20% | 62.0% |
| 30% | 76.2% |
| 40% | 85.8% |
| 50% | 93.2% |
| 60% | 97.9% |
| 70% | 99.2% |
| 80% | 99.7% |

Across the city, heat pumps sized to 50% of peak building demand meet the same fraction of thermal demand as the **Smart Multi Vector** solution (see Table 7); intelligent use of thermal storage might increase this share.

The grid upgrade, and 25-year fuel and emissions costs[20], are shown below for a range of heat pump sizing fractions; fuel and emissions costs are calculated as in the previous section.

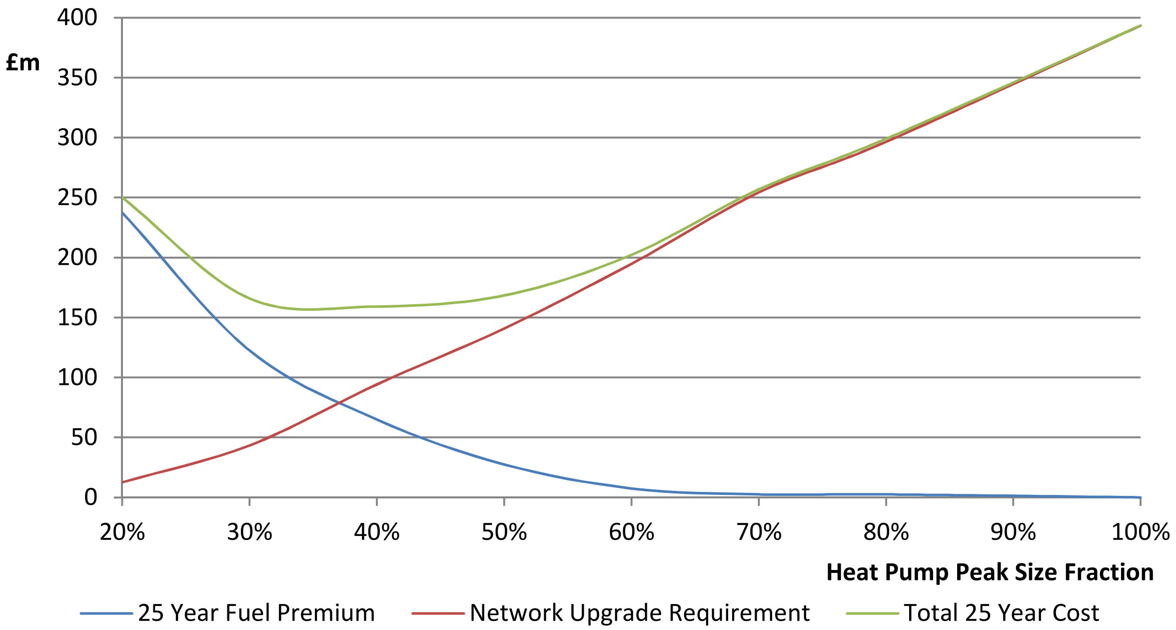


*Figure 1 – Undiscounted Fuel Premium and Grid Reinforcement Costs by Heat Pump Size Fraction*

[19] 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).

[20] The premium over totally electrified heat, we note that no unit cost reduction is included for smaller heat pumps, and a constant carbon price of £200 per tonne is used - 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.**

### 3.1.5 Barriers and Innovation Requirements

The key barriers and innovation requirements are explored below, a more complete and detailed list of can be are found in the accompanying report *D5.1 Barriers to Multi Vector Operation*.

#### Incentivization and Value Sharing

Investment and coordination are required to realise the value of multi vector supply, to:

- Create the required telemetry and control platforms
- Incentivize consumers to choose hybrid, rather than pure electric systems.
- Ensure continued, affordable operation of the gas network.

Despite the large social savings of multi vector heating, a mechanism will be required to incentivise take-up of multi vector heating technologies by consumers and housing developers.

Home energy controllers will enable improved control over consumer energy demands and their use as part of demand-side management systems, either involving direct load control or response to pricing signals, is an area of considerable interest. The commercial framework for demand management of consumer loads (particularly in the domestic sector) is not yet well established (both in terms of commercial offers to consumers and the ability of DNOs to access demand flexibility alongside other actors, e.g. supplier-led demand side response).

Encouraging multi vector heat supply will require:

- Reflection of the system value of supply flexibility in support mechanisms for domestic low carbon heating.
- Design of a mechanism to leverage avoided grid upgrade to incentivise hybrid heat pump uptake and (depending on implementation) a control platform.

Both of which require an understanding of the role of heat pumps in the transition to low carbon heating.

#### Gas Networks as a Peak Supply Vector

Despite the significant expected drop in gas use by 2050, it will be difficult to decommission any of the gas network, so that network depreciation, return and O&M levels will need to be maintained near current levels. We note that Iron Mains Replacement Programme (IMRP) - which comprises over half gas DN current expenditure - is scheduled to conclude around 2032. Once complete, there are expected to be many fewer leaks from the LP mains. Together, reduced network investment requirements and lower maintenance and service costs will lead to a significant drop in gas network O&M from the 2030's onwards. Low utilisation therefore presents economic issues in terms of cost recovery for the network operators, who must recoup their largely fixed network costs over a much-reduced volume of gas transported, resulting in a significantly increased network cost component of the overall gas supply cost. A new pricing structure, which shares gas distribution network costs equitably across gas boiler only and multi vector (peak gas) users may be needed, this would have to be determined and agreed by the regulator.

- **2050 gas demand might fall to around 25% of its 2016 levels as 65% of homes are electrified and building fabric is improved – gas DNs are unlikely to reduce their costs to the same extent. Under the current charging regime, this would lead to an increase**

**in transportation costs and therefore per unit gas prices on domestic fuel bills, which may significantly impact persistence gas users.**

The implications of usage pattern changes for the operation and economics of the gas networks, and the resulting cost of gas to consumers, are discussed in more detail in appendix 7.1.3.

### Domestic DSM

Failure of householders to reliably switch to gas heating during electricity network peaks could at worst rule out DSM as a network management technology, or at best negate the environmental benefits of large scale electrification of heat. The heat supply control mechanism, and its ability to match demand using the appropriate supply vector, is key to this solution - without it users may for example operate their heating systems to minimise bills, irrespective of grid loads. In addition to the questions around implementation and performance, control of home heating technologies raises significant consumer acceptance as well as potential data privacy and cybersecurity issues.

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:

1. 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 connected homes allowing communication with devices within individual homes, potentially through the smart metering system, and for the electric and gas heating devices (which may be separate or hybrid) to be able to communicate.
2. Widespread roll-out of time-of-use pricing will require smart meter roll-out, and the introduction of half-hourly settlement for domestic and small commercial customers; it will also require that suppliers pass network charges through to customers. Some studies on ToU tariffs (referenced in the report *D5.1 Barriers to Multi Vector Operation*) have been conducted, but further work is required, encompassing:
    - Efficacy - the relationship between price increase and demand moved, particularly for multi vector heating, where consumers should not notice vector switching.
    - Their effect on demographic groups and customers who are not individually metered, such as prepayment scheme or housing association members.
    - Concerns around consumer engagement, particularly given the government's drive toward simpler retail tariffs.
3. Constraining the electrical load that heat pumps impose on the electricity network by limiting heat pump capacity. 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. 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). This solution may need to be combined with another mechanism, such as time of use pricing, to ensure additional electric heaters (e.g. electric convection heaters) are not used to meet peak demands, and to ensure that gas use is limited to the peak periods.

### DN Telemetry

Where implemented through responsive means, such as direct load control or variable tariffs, the multi vector heat control platform will need real time load data from substations and, to maximise multi vector value, feeders. Current DNO monitoring capabilities are largely confined to the HV system. In addition to the requirement to share value with GDNs, and engage with heat pump manufacturers, multi vector heat supply will require DNOs to upgrade their infrastructure monitoring capabilities.

Smart meter rollout may represent at least a partial solution to this problem – demand data may allow upstream substation and feeder loads to be inferred, particularly where they are combined with other data and forecasts to create short term predictions of grid component loads.

## 3.2 Case 2: Gas CHP and Heat Pumps supplying Heat Networks

### 3.2.1 Introduction

#### Context

By 2030, district heating could provide around 42 TWh[21] of domestic heating demand – around 15% of the UK total[22]. 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[23] - 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[24]. 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.

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

[22] ECUK Data 2016

[23] BEIS - CHP Focus

[24] 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.

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.

### 3.2.2 Data and Analysis

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 scheme costs for different plant options.

#### Overview of Model Operation

The Case Study model represents the energy system economically:

- hourly thermal demand profiles and building level annual totals are combined to calculate a bottom-up hourly scheme demand profile, which is then diversified.
- The model then determines the lowest cost dispatch option to meet hourly thermal demands

Three potential options for low carbon heat supply are analysed, shown below (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 mode that provides the required heat at lowest total cost.

*Table 11 – 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 boiler.</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[25]</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[26]</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</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>

[25] As ground source heat pumps are considered seasonal variation in CoP is minimal

[26] CHP engine and heat pumps are sized so that the HP draws the full electrical output of the CHP engine; the CHP engine is sized to 40%, and the HP sized to 60%, of their single vector equivalents.

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.

A summary of the model assumptions and parameters is shown below.

*Table 12 – Summary of Model Data Sources and Assumptions*

| Model Parameter | Source / Description | |
|---|---|---|
| **Thermal Demand and Diversification** | Hourly space heating demand values are taken from Carbon Trust field trial data, hot water demand is taken from Energy Saving Trust data. Total thermal demand profiles are diversified according to connection numbers. | |
| **Plant Costs** | Capital and O&M costs are taken from *Research on District Heating and Local Approaches to Heat Decarbonisation*[27]. | |
| | **Gas CHP** | £0.65m/MWth |
| | **Ground Source Heat Pump** | £1.9m/MWth |
| | **Hybrid System** | £1.4m/MWth |
| **Network Costs** | 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. | |
| **Storage Costs** | 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). | |
| **Plant Efficiencies** | **CHP Efficiency** | 55% thermal, 25% electrical |
| | **HP CoP** | 4.4 at 60°C. A sensitivity at a supply temperature of 75°C (at a CoP of 3.4) is included. |
| | **Boiler efficiency** | 85% thermal |
| **Fuel Prices** | Gas and power prices are taken from the ESME Reference (low renewables, low power price volatility) and Decarbonisation (high renewables, high power price volatility) scenarios. | |
| **Network Use Costs** | 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; data for the WPD East Midlands area are used. Generator time of use (GDUoS) revenues are not included. | |
| **Carbon Prices** | CCC Carbon Price scenario are used in the reference case, sensitivity analyses consider the BEIS Central and High Carbon Price scenarios. | |
| **Economic Parameters** | Schemes are assessed on their total costs over at a 25-year lifetime, at discount rates of both 3% - corresponding to a societal perspective – and 10% - corresponding to the perspective of a private developer. | |

[27] For a heat pump capable of supplying hot water temperatures (above 60°C) at a CoP of 4 or above.

### 3.2.3 Multi Vector Benefit

Our findings on lifetime supply costs for heat networks are shown below.

#### Plant Sizing

25-year scheme costs, as a function of principal plant size (as a fraction of the peak demand), are shown below for the three heat supply options (at a 3% discount rate).

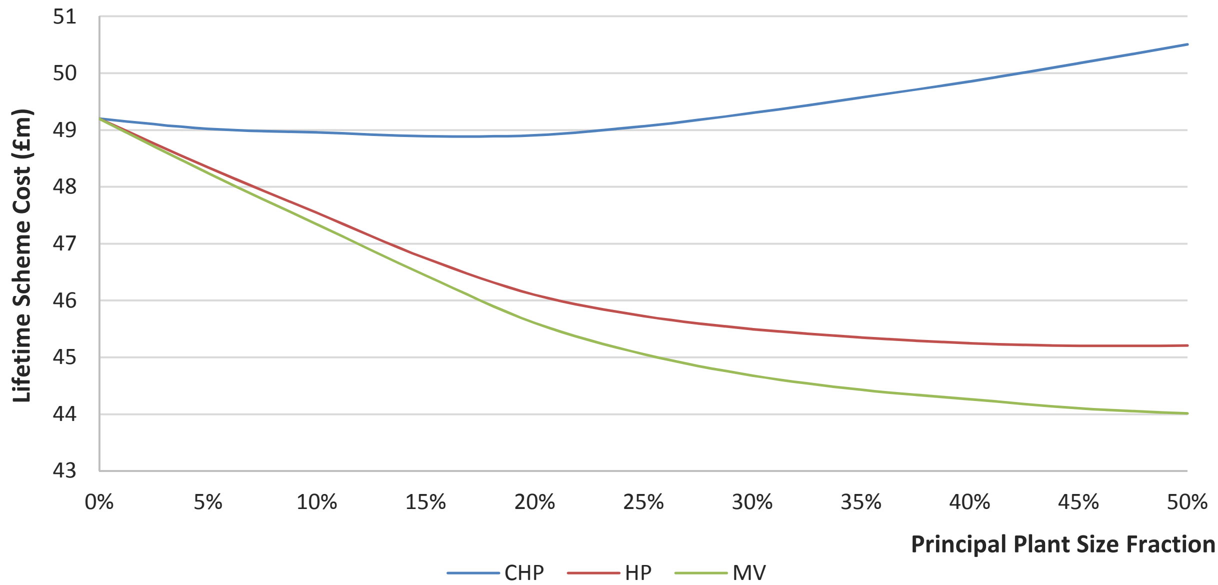


*Figure 2 - Effect of Plant Sizing on Total Project Cost at a Discount Rate of 3%*

- **Multi vector supply configuration provides the lowest cost means of low carbon heat supply at all plant sizes.**
- **At low discount rates, CHP scheme costs initially fall slowly with increasing thermal size, but increase above 20% peak thermal demand, and are not competitive with heat pumps or multi vector supply. The future energy system potential for gas CHP exporting to the grid appears marginal under these price projections and grid carbon emissions levels.**

#### Price of Heat

Total scheme costs with low carbon plant sized to 50% of peak network demand, are shown below, along with the corresponding breakeven price-of-heat.

*Table 13 – 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** |
| 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 |

*Table 14 – 25 Year Price of Heat (£/MWh)*

| | DH Primary Plant | | | | | |
|---|---|---|---|---|---|---|
| **Discount Rate** | Local Gas Boilers | Gas Boiler Only | **CHP Only** | **HP Only** | **MV** | **MV Saving** |
| 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 heat supply saves around 3% compared to alternative supply modes at low discount rates.**
- **Private developers, e.g. Esca's, operating at higher hurdle rates and therefore preferring lower capital costs, are likely to install less low carbon plant, and supply more heat using a gas boiler. Their incentives might be aligned with social perspectives through a combination of up-front subsidy for low carbon plant, and regulations requiring low carbon heat networks.**

### Plant Use

The proportion of run time in each multi vector DH mode is shown below.

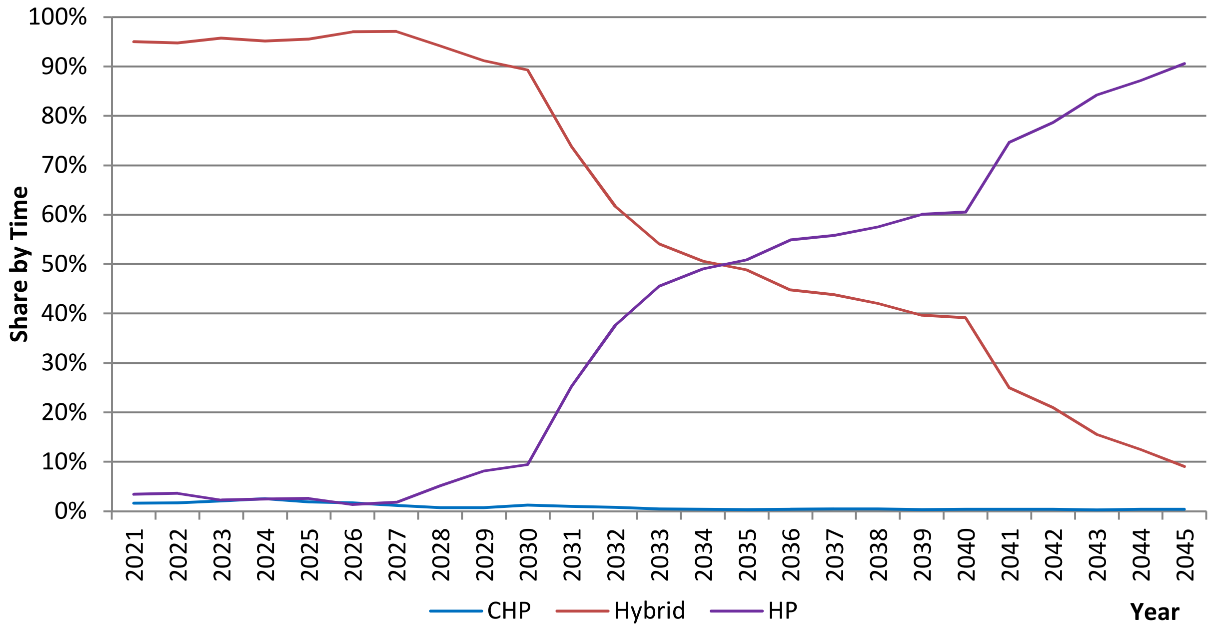


*Figure 3 –Multi Vector Supply Mode Breakdown by Year*

- **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/tonne. In hybrid mode, the DH scheme runs independently of the grid; as grid connection costs can be significant operators may consider not connecting a multi vector scheme to the electrical network. However, we find that the opportunity costs of running exclusively in hybrid mode increase across the scheme lifetime, and equate to 2% of total project**

**lifetime cost, or £0.1m/MWth peak scheme demand – this is unlikely to be economic at typical grid connection costs.**

- **Although it becomes increasingly unviable at high carbon prices; multi vector district heat – whether connected to the grid or not – may represent an intermediate step in decarbonisation of heat.**

### CHP Export

The minimum electrical price at which CHP generation is exported to the grid is shown below by year, for the single vector CHP and multi vector schemes. We show also the costs for an open cycle gas turbine (OCGT); typically used for intermittent or backup generation (both the short-run marginal and levelised costs are shown)[28].

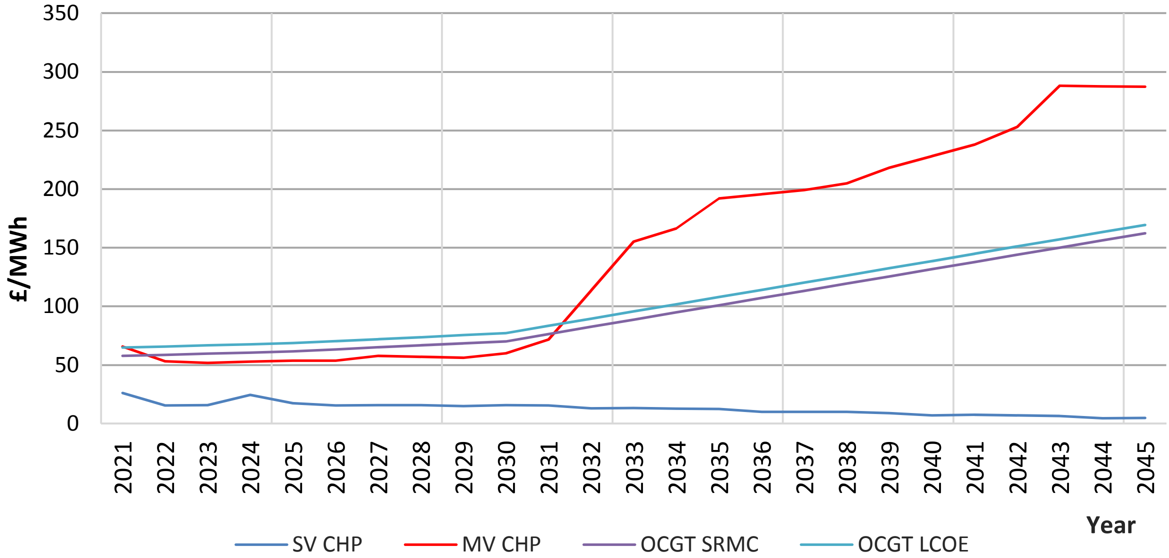


*Figure 4 -Minimum CHP Export Prices by Year, and SRMC and LCOE of OCGT*

- **Standalone CHP provides a low-cost source of peak shedding, though it may be a more expensive energy system solution overall than multi vector heat supply and OCGT.**
- **Multi vector schemes do not export significant CHP generation to the grid (and total export revenues are small, at less than 1% of total lifetime costs). Power prices for multi vector export are lower than gas turbine generation until 2030 though, so such schemes may provide peak generation until then, and potentially ancillary services beyond this point (multi vector heat networks have a peak power output of 10% of peak thermal demand).**

[28] The capital and operational costs are as specified in Case Study 3, though a 3% discount rate is used.

## Sensitivity Analysis

The effect of model assumptions on multi vector benefit, particularly CHP export and carbon prices; are explored in this section.

### Carbon Price

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.

Heat supply costs are shown below for the 3 heat supply options by year; carbon prices represent the dominant macroeconomic driver of differences in scheme operating costs over their lifetimes.

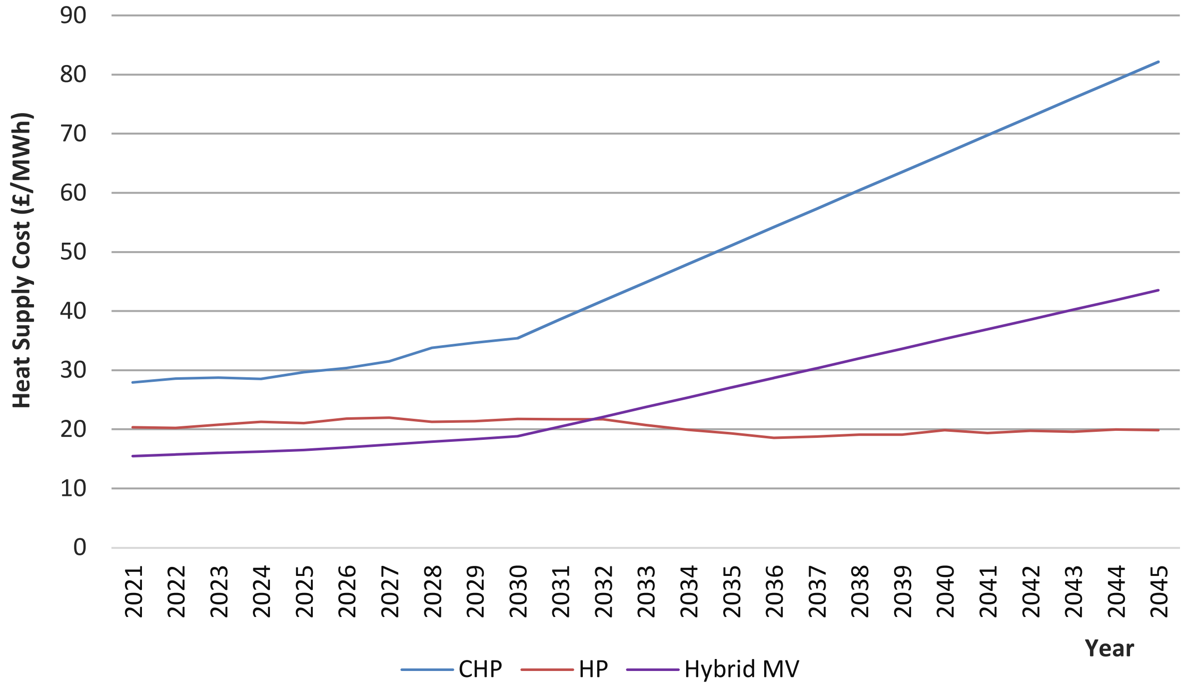


*Figure 5 – CHP Export, HP and Hybrid Multi Vector Heat Supply Costs by Year*

*Table 15 – 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 |

- **Carbon price is the main driver of changes in multi vector scheme operation across its lifecycle, with hybrid mode used decreasingly above £100/tonne; multi vector operation however remains the lowest cost means of heat supply across our carbon price scenarios.**

  **Multi vector benefit is driven by operation in hybrid mode– independent of the electrical grid – as hybrid mode becomes increasingly expensive, the benefit falls.**

### Local Use of CHP Cogeneration

CHP generation can be exported to the grid, or used to offset local demand, in the latter case, the pass-through charges effectively also accrue to the CHP operator. Annual scheme running costs are shown below where all CHP power can be used locally (plant operation remains heat led, i.e. where there is demand for power but not heat the CHP remains idle).

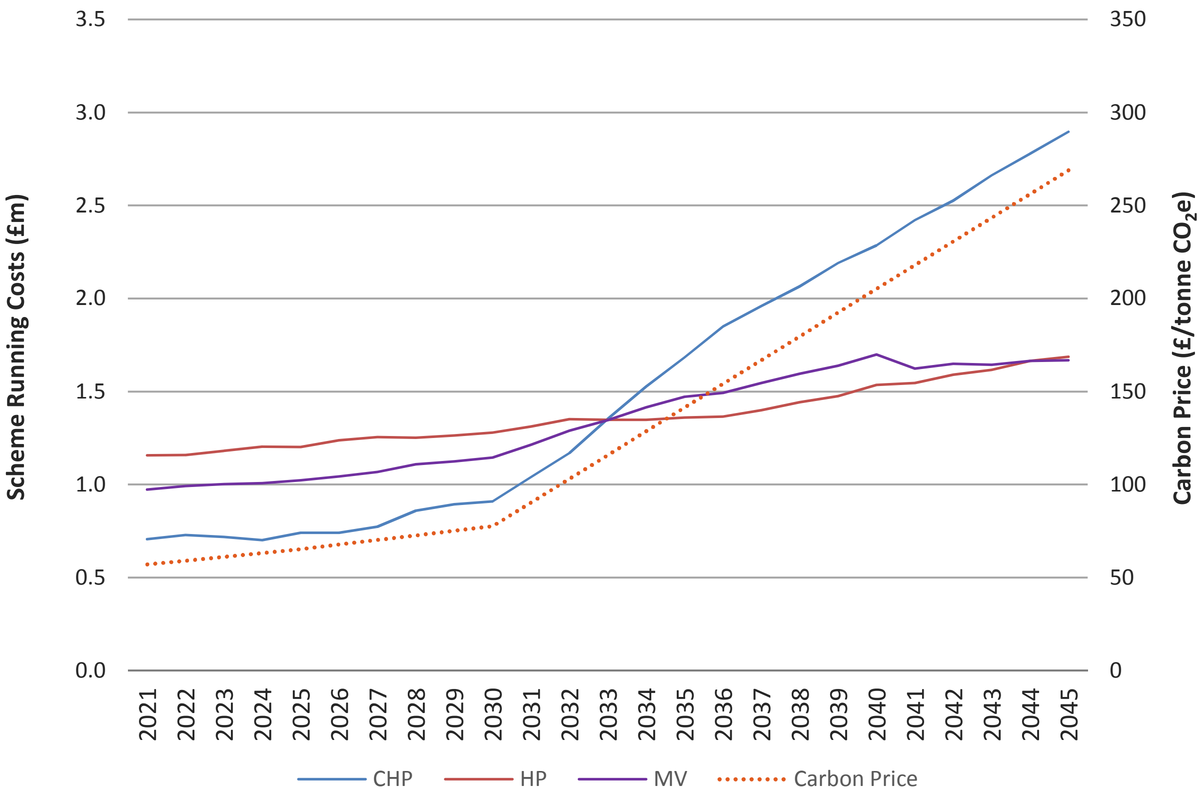


*Figure 6 – Annual Scheme Running Costs and Carbon Price, CHP Generation Used Locally*

CHP engines run when electric prices are high; displacing peak generation plant rather than renewables or nuclear baseload; the emissions offset by CHP power are therefore based on the efficiency of a modern CCGT (around 45%). Where CHP engines run at high load factors this will underrepresent their 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 average annual intensity; we include both emissions intensity calculations in the scheme lifetime cost table below.

*Table 16 – 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 |
| CHP Offsets CCGT Cogeneration Used Locally | 60.97 | 49.72 | 40.61 | 45.21 | 42.48 | -1.87 |
| CHP Offsets Grid Average Cogeneration Used Locally | 60.97 | 49.72 | 47.84 | 45.21 | 43.63 | 1.60 |

- **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.**

The returns of CHP schemes can be significantly increased by offsetting local grid demands. Heat pumps that are installed in close proximity to a CHP system – perhaps supplying heat to an extension of the CHP network, or a nearby independent scheme – are ideal candidates, as their power demands are likely to substantially coincide with export from the CHP system. By connecting through a private or virtual private network, CHPs and heat pumps would effectively form a multi vector network, avoiding or reducing grid use pass-through charges.

Where customers for CHP cogeneration cannot be found, this value may be sufficient to finance CHP operator purchase of an appropriately sized heat pump, or heat pump operator a CHP engine, to augment their existing plant. For example, a 1MWth CHP engine might be included in a 2MWth single vector, or a 5MWth multi vector, DH scheme. Despite the additional capital cost of a 1.5MWth heat pump (bringing the total thermal generating plant capacity to 50% of peak network demand), the latter scheme's lifetime costs are £4m lower (see Figure 2). Similarly, the operator of a 3MWth heat pump might buy a 2MWth CHP engine, reducing overall scheme costs by around £1m.

- **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 of connecting to other private wire counterparties.**

Further sensitivity analyses are summarised below, supporting model data can be found in appendix 7.2.1.

*Table 17 – Sensitivity Analyses*

| Parameter | Finding |
|---|---|
| Power Price Volatility | 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 65% of the reference case value. |
| Network Temperature | Multi vector heat supply remains the lowest cost low carbon solution (and CHP the highest) when supplying legacy buildings. |

### Applicability

Our analysis models a 9MW heat network, serving 8,000 homes and a handful of commercial and government buildings, the network and plant costs are priced on a per MW basis, so our results are more widely applicable. The relevance to the wider energy system, and unmodeled alternatives, are summarised below.

*Table 18 – Applicability of Case Study Analysis*

| Parameter | Wider Relevance |
|---|---|
| Thermal Demand Profile | **The highly diversified profile should not limit the relevance of analysis.**<br>Our analysis is based on a large DH scheme; the findings should however be applicable to heat networks across a range of heat demand totals.<br>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. |
| Bio CHP | **Low carbon fuel could make CHP more competitive with heat pumps.**<br>Carbon costs of gas CHP heating comprise around £2.4m/MWth of lifetime costs (at 3% discount rate), nearly 4 times the capital cost. 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[29]. A biogas or bio-crop CHP operating at a lower carbon intensity may therefore improve the prospects of standalone CHP, depending on scheme size, gas and biofuel costs, and project financing structures. |

### 3.2.4 Barriers and Innovation Requirements

Significant challenges associated with the transition to multi vector operation have been collated through consultation with industry stakeholders and other experts, and are summarised below. More detailed analysis is provided in the accompanying report *D5.1 Barriers to Multi Vector Energy Supply.*

### Real Time Energy Centre Price Optimisation

**Optimising multi vector heat supply mode to half hourly electricity prices requires that the system operator has access to these prices, and that the plant can be ramped up and down sufficiently rapidly.**

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

Electricity suppliers are required to settle their positions in the market on a half hourly basis, and will contract with users and generators for amounts of energy up to gate closure (one hour before the start of the corresponding settlement period)[30]. This notice period will determine the plant ramp time requirements for heat schemes that import and/or export electricity to and from the grid.

Gas turbines are currently the main source of short and medium timescale turn-up services to the National Grid, and are awarded Frequency Response (FR) and Short Term Operating Reserve (STOR); availability payments for increasing 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", kept warm but producing negligible output. To allow the scheme to ramp up and down in response to movement in the electrical price, CHP engines and boilers must run in an intermediate low-throughput mode; it may be possible to use some of the heat and power produced in idling mode. As with all thermochemical plant, ramping up and down may lead to increased wear and lower efficiencies.

More fundamentally, CHP operators need access to wholesale electricity market prices, to which plant operation can be adjusted - depending on the requirements and logistical costs of access to the wholesale market, it may be lower cost to secure a long term PPA with an electrical supplier. CHP plants on the 10MWe scale typically make such arrangements.

We note however, that hybrid operation – in which a CHP powers an on-site heat pump, and both supply heat to the network - constitutes the optimum heat supply configuration for over 90% of run hours at carbon prices below £90/tonne, in this configuration power import and export prices are immaterial to scheme returns.

### Solutions and Mitigations

DUoS variation is entirely - and wholesale price variations are somewhat – predictable[31]; operators of multi vector schemes therefore have considerable foresight of both power prices and scheme demand levels (from e.g. weather forecasts, historic data). Significant optimisation to diurnal power price variation should therefore be possible using current technology and market design. To incentivise flexible operation of the CHP and heat pump, any PPA might be structured to comprise a large fraction (>90%) of the wholesale cost, rather than a flat fee. Alternatively, several multi vector heating schemes could form a single commercial unit, and offer their combined output to the UK market collectively.

- **There are few barriers to hybrid multi vector heat supply – using a CHP to power a heat pump – and the hybrid configuration constitutes the lowest heat supply option at carbon prices below £90/tonne. The system value of heat supply flexibility - the potential to absorb surplus, and mitigate scarcity, of electricity - is however dependent on heat network operators access to the wholesale electrical price. Currently, schemes of this scale do not typically trade their electrical demand and generation on the open market, but commercial arrangements such as PPA design and pooled generation, might allow future DH operators to realise much of this value.**

[30] BSC P305: Electricity Balancing Significant Code Review Developments

[31] Many industrial facilities use on-site diesel generators to avoid network use at red band DUoS times.

## 3.3 Case 3: PiV Fuel Switching

### 3.3.1 Introduction

#### Context

As transport is electrified, many electric vehicles are being produced with both a petrol or diesel engine, and an electric motor. As these vehicles comprise an increasing fraction of the total parc, 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 ability to flexibly supply this energy through power or liquid fuels.

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 21$^{st}$ century, over 40% of generation will be renewably supplied[32].

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[33] 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 2050 parc and vehicle kilometres travelled (VKT) projection used in this analysis has been chosen as it includes significant hybrid vehicle uptake. 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.

#### Case Study Aims

This Case Study aims to identify circumstances when there is system benefit in switching PiVs 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.

[32] Updated energy and emissions projections: 2015

[33] 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".

### 3.3.2 Data and Analysis

Data in this study are taken from the ECCo model, the workings of which are described in appendix 7.3.1.

*Table 19 – Summary of Model Data Sources and Assumptions*

| Model Parameter | | Source / Description |
|---|---|---|
| Relative vehicle electrical and liquid fuel efficiencies | | Calculated as the energy content delivered divided by the distance driven in each mode[34]; liquid fuel efficiencies range from 21% to 30% of the values for electrical supply. |
| Liquid Fuel Price Components | Fuel Cost | 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; at the current oil price of £40/barrel we estimate a 2050 price of 34p/litre. |
| | Ex-Refinery Spread | A margin comprising refining, distribution and profit of 6p/litre is used, based on a UKPIA[35] study. |
| | Carbon Price | The BEIS central carbon price of £212/tonne is used, corresponding to between 56 and 64p/litre, around the same as current duty levels. |
| 2050 Generation Mix | | The 2050 electrical generation fleet makeup is determined by the ESME model; to emphasise the effect on system prices of a low renewable output, the high renewable (94GWe installed by 2050) scenario from Case Study 4 is used; the projected generation fleet is shown in appendix 8. |
| Weekly Winter Wind Capacity Factors | | 10-minute Gridwatch data from 2010 to 2016 have been parsed for 1-in-20 year minimum weekly wind power capacity factors. As these reflect mostly onshore wind, and offshore wind will make up a larger share of generation by 2050, they have been revised upward slightly (a minimum winter capacity factor of 15% has been used). |
| Power Prices | | Hourly wholesale electrical prices are calculated in PLEXOS for the generation mix and capacity factors above, including emissions costs.<br>DUoS charges are also included to capture the network usage costs. |

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

[35] UKPIA - Understanding Pump Prices

### 3.3.3 Multi Vector Benefit

#### Marginal Cost Calculation

In the ESME high-renewable scenario, peak electrical generation is provided by gas and hydrogen turbines, with nuclear providing around 27GW of baseload (see appendix 7.8). On this basis, OCGTs operate 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.

#### Hourly Power Market Costs

Hourly power prices have been modelled based on the relative balance of demand and available generation across a two-week low wind speed period in January 2050. During this period, the modelled wholesale electrical prices rise to a maximum of £330/MWh, around £440/MWh when peak time of use charges are included. Total PiV electric demand in this period is 338 GWh - 3.8% of total power demand.

Electrical energy supply costs rise above those of liquid fuels for a maximum of 19 consecutive hours; electrical and liquid fuel supply prices, and the hourly system switching value, are shown below for this period and the subsequent 5 days.

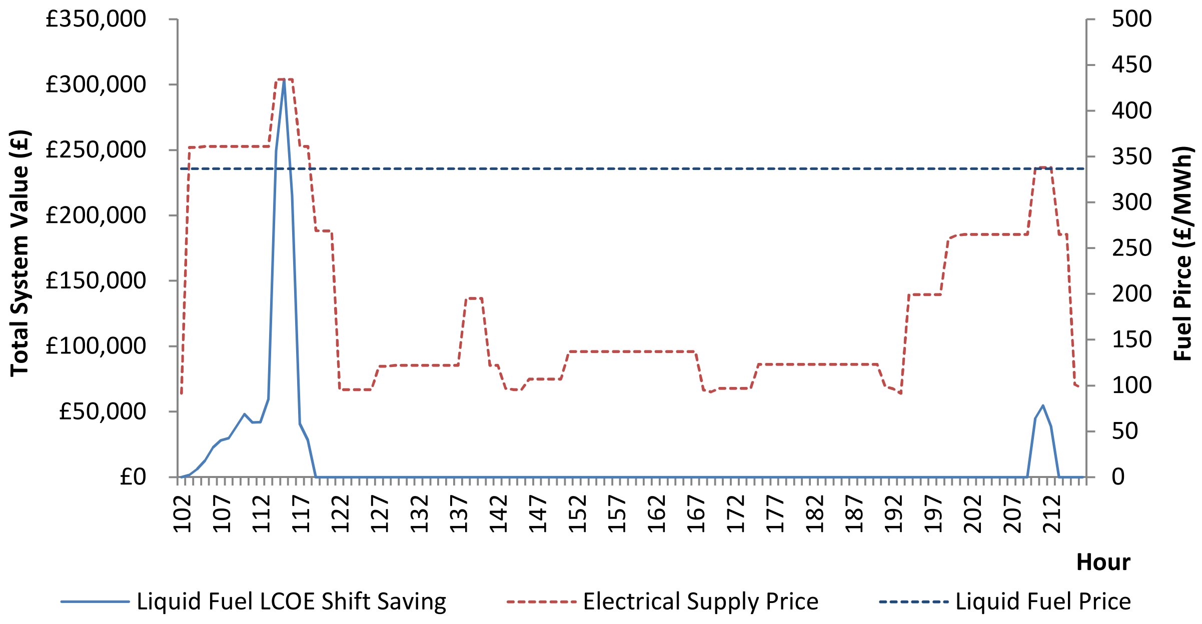


*Figure 7 - Hourly Energy Prices and Fuel Switching Value for 5th to 9th January*

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.

- **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. PiV liquid fuel switching is – at best – a marginal multi vector supply option.**

### Single Vector Alternative

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).

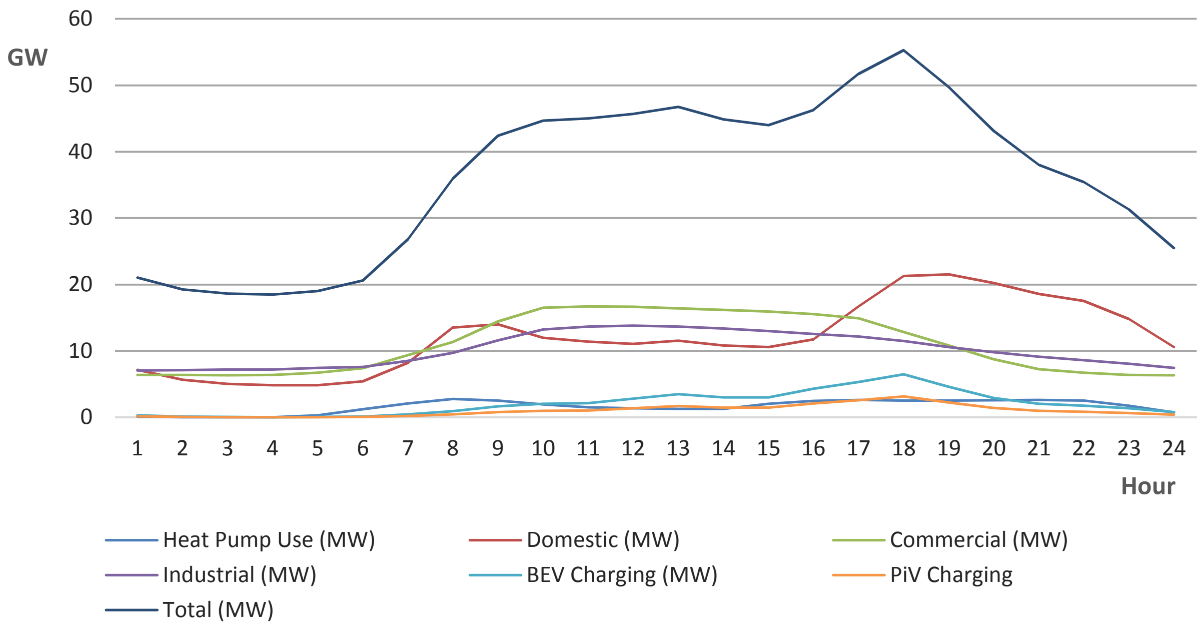


*Figure 8 – 2050 January Peak Day Diurnal Demand Profiles*

Peak-day demand levels vary from 18.5GW in the early morning to 54.5GW in late evening; a difference of 36GW. 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. 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.**

### Sensitivity Analysis

*Table 20 – Sensitivity of Case Study Analyses*

| Parameter | Finding |
|---|---|
| Gas to Oil Price Ratio | 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 (data are shown in appendix 7.3.2). |
| Carbon and Other Environmental Costs | 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. |

## 3.4 Case 4: Power to Gas – Transmission Level RES to $H_2$ and RES to $CH_4$

### 3.4.1 Introduction

Decarbonisation of electricity is a fundamental part of the UK's pathway to meet its 2050 decarbonisation target. It is expected that renewables will play a very important role in achieving this. However, with high levels of intermittency, there may be periods when electricity supply exceeds demand. This over-generation of low-carbon, low-variable-cost energy could be exported to other markets subject to their demand levels and interconnection capacities. When that is not possible, that excess renewable energy would have to be curtailed, unless there is some way to store it for longer periods of time.

Electrolysis is a multi vector solution and a form of Power-to-Gas (P2G) technology converting electricity into $H_2$ gas, which can then be blended into the existing natural gas grid, up to certain concentration limits, or used to supply other $H_2$ markets. The produced $H_2$ can also be converted to methane using catalytic methanation; a common process for hydrogenation of carbon dioxide. In the latter case, the product is synthetic natural gas (SNG), which can be injected into the gas grid without concentration limit as it complies with grid specifications[36].

Both P2G technologies allow the existing natural gas grid to be used as a storage solution, providing support to the electricity network at times of stress. While providing the power sector with more flexibility, P2G techniques also allow for the cross-sectoral integration of surplus renewable energy in markets such as transport and industry that can benefit from further decarbonisation.

This section reviews the economic viability of electrolysis (Power-to-H2) and methanation (Power-to-SNG) for the curtailment of renewables in the UK, under 2050 scenarios where installed renewable capacity is high. The system benefit of using these multi vector configurations is then compared against the benefit of using economically sensible single vector means of alleviating curtailment.

[36] Pure methane meets the Wobbe Number requirements for grid injection, though to meet current commercial calorific value (CV) requirements under the FWACV regime it must typically be blended with propane or butane, which represents an additional cost to the injection facility. As this analysis considers the 2050 energy system and alternatives to the FWACV are currently being trialled, this is not considered further here (the effects of FWACV on injection facilities is discussed further in section 3.8)

### 3.4.2 Data and Analysis

The potential of electrolysis from zero cost oversupply as a solution for dealing with renewable curtailment is examined under increasing levels of wind generation capacity in the UK in 2050 (the three scenarios modelled in ESME are shown in appendix 7.8). Model structure and assumptions are described below.

*Table 21 – Summary of Model Data Sources and Assumptions*

| Parameter | Source / Description |
|---|---|
| Whole energy system | Modelled using ESME V4.1; 2050 capacity of onshore and offshore wind are constrained to a given minimum level; ESME then returns:<br>• installed generation capacity mix[37]<br>• Security of supply<br>• nodal electricity demand per seasonal and diurnal time-slice<br>• required interregional transmission capacity<br>• an $H_2$ shadow price – used as a proxy for the wholesale price.<br>These are shown in appendix 8. |
| Hourly Operational Dispatch | PLEXOS is used to calculate hourly demand levels from ESME and exogenous hourly wind, tidal and solar load factor profiles, based on historical data (2008) of UK regions. |
| Electrolyser Sizing | Capacity potential for electrolysis and methanation is assessed using:<br>• hourly renewable curtailment results from above<br>• technology-specific data (such as capex, O&M, efficiency)<br>• scenario-specific $H_2$/gas and carbon prices<br>The economically sensible capacity of the asset is found at the point at which the levelised marginal unit cost is equal to the $H_2$ (or gas) wholesale price. |
| Single Vector Alternatives | The single vector alternative comprises selective transmission reinforcement, and battery storage, sized as follows:<br>• Total additional capacity required on each transmission line connecting UK regions is identified.<br>• The effect on curtailment of increasing grid reinforcement is determined[38]<br>• The system benefit is evaluated based on the reduction of the total generation cost, driven by the reduction of low-cost generation spilling[39]. |

[37] Including 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. Also ensures sufficient flexibility from the electricity generation fleet at a system level to meet estimated rates of change in electricity demand

[38] We note this does not involve a formal optimisation process for determining the optimal size and location of the single vector technologies.

[39] Absorbed power is priced at grid average prices.

Technical modelling data are shown below:

*Table 22 – Electrolyser (power-to-$H_2$) technical and economic data (ESME 2050)*[40]

| | Base | High | Low |
|---|---|---|---|
| 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 | | |
| P2G Efficiency (%) | 80 | | |
| Cost of capital discount rate (%) | 8 | | |

### Degree of Decarbonisation Required for Substantial Renewable Oversupply

The degree of renewable generation capacity required for significant electrolysis from renewable oversupply, the overall generation mix consistent with this, and the associated carbon price are discussed in appendix 7.4.1. We find that power to gas at significant scale requires around 94GW renewables (over 60% of total generation capacity), and that this is achieved under a 2050 carbon price of £545/tonne (corresponding to the ESME High Renewables scenario).

[40] All data are taken from ESME, except the electrolysis efficiency, which is based on the figure reported in the report for Leeds H21 project (80%); significantly higher than the ESME figure (69%).

### 3.4.3 Multi Vector Benefit

## Electrolysis

The following table shows total electrolyser capacity and output across a range of capex and hydrogen prices. We have considered:

a. the ESME $H_2$ cost for the High Renewable scenario of £28/MWh, equal to the modelled gas price
b. 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)[41]
c. the estimated $H_2$ sale price in the H21 Leeds project of £50/MWh.[42]

*Table 23 – 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 electrolyser plant lifetime breakeven load factor, however, because the ESME curtailment duration curve is "blocky", a lower minimum load factor might not necessarily lead to a higher capacity of electrolysis in the modelling. Thus, despite the low capex and high shadow price scenarios both requiring a lower load factor, there is no effect on electrolysis size or output. Where capex is reduced and the $H_2$ price is increased, up to 9TWh (40%) of oversupply might be converted to $H_2$ and injected into the gas grid.

41 BEIS 2015 Fossil Fuel Price Assumptions

42 The total hydrogen sale price quoted in the Leeds H21 project report is £76/MWh, which 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.

## Methanation

In this section we investigate methanation - the production of $H_2$ via electrolysis followed by a subsequent methanation step to produce gas - as a P2G solution. An economic level of methanation has been derived using the methodology and renewable oversupply data above, and the technical data below:

*Table 24 – Methanation (power-to-SNG) technical and economic data*[43]

| | 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 | | |

A key difference between electrolysis and methanation – apart from the further efficiency loss and additional capex – is that methanation requires $CO_2$ to convert the electrolysis-produced $H_2$ to methane. Hence the cost of carbon will affect scheme value. Three scenarios for carbon feed have been investigated; explained in appendix 7.4.2. The following table shows the economic level of methanation results under the ESME High Renewables Scenario for the three different carbon cost cases.

*Table 25 – Methanation results under Different $CO_2$ Costs*

| Parameter | Zero Carbon Price | Negative Carbon Price | Positive Carbon Price |
|---|---|---|---|
| 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 | NA |
| 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 |

[43] ESME V4.1 does not include economic and technical information for the methanation reactor. Assumptions were instead taken from a study on P2G solutions by ENEA Consulting. This efficiency loss from electrolysis (20%) and the methanator's carbon consumption per unit gas produced are also based on this study.

- **Methanation is viable only where $CO_2$ that would otherwise be vented to the atmosphere can be absorbed. An obvious source of this $CO_2$ might be the carbon emissions from 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.**

## Single Vector Counterfactual – Selective Reinforcement and Electricity Storage

Some curtailment is caused by limited transmission capacity between UK regions, so local transmission grid reinforcement could reduce the renewable curtailment, though local reinforcement will not alleviate system-level generation surplus caused by national supply exceeding demand at particular times. A range of solutions might reduce reinforcement, including:

- electricity storage
- demand side flexibility
- expansion of UK interconnection to neighbouring markets

We focus here on the potential for battery storage to alleviate residual curtailment following local grid reinforcement; cost data are shown in appendix 7.4.3.

## Selective Grid Reinforcement

PLEXOS models power flows across transmission boundaries, and determines the level of constraint on all boundaries. To understand the economics of reinforcement, we model 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). Results across the reinforcement scenarios are shown below.

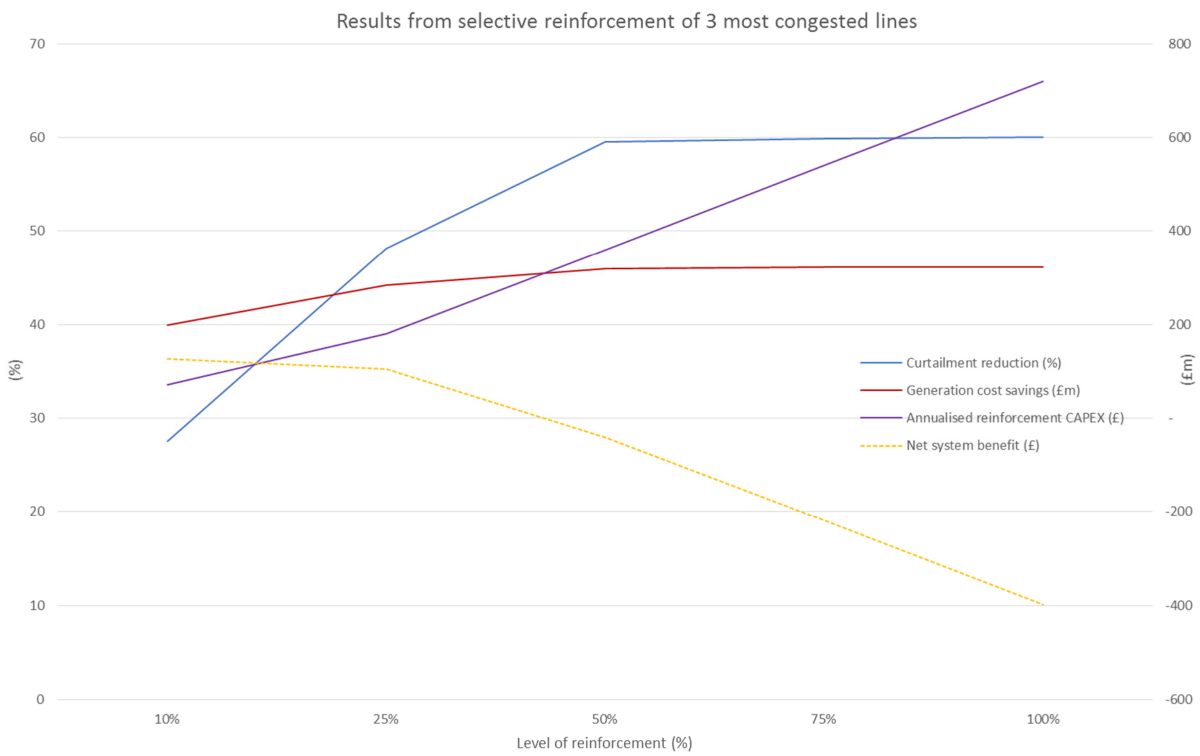


*Figure 9 – Results from selective transmission reinforcement*

Curtailment levels improve with increasing levels of reinforcement, as do savings in total UK generation cost. However, these savings come at significant investment cost, with the overall net system benefit gradually decreasing; the most economically sensible solution is the 10% (5GW) reinforcement scenario which has the highest net system benefit.

## Battery Storage

To determine the economic attractiveness of using a battery to alleviate curtailment, we tested a range of sizes of batteries located in Scotland: 5GW/1hr, 5GW/2h, 10GW/1h, and 15GW/1h. The results are shown below; despite decreasing curtailment spill and total generation cost savings increasing slightly as battery sizes increase, the high battery capex leads to significant net system cost increases; the net system benefit is negative in all cases.

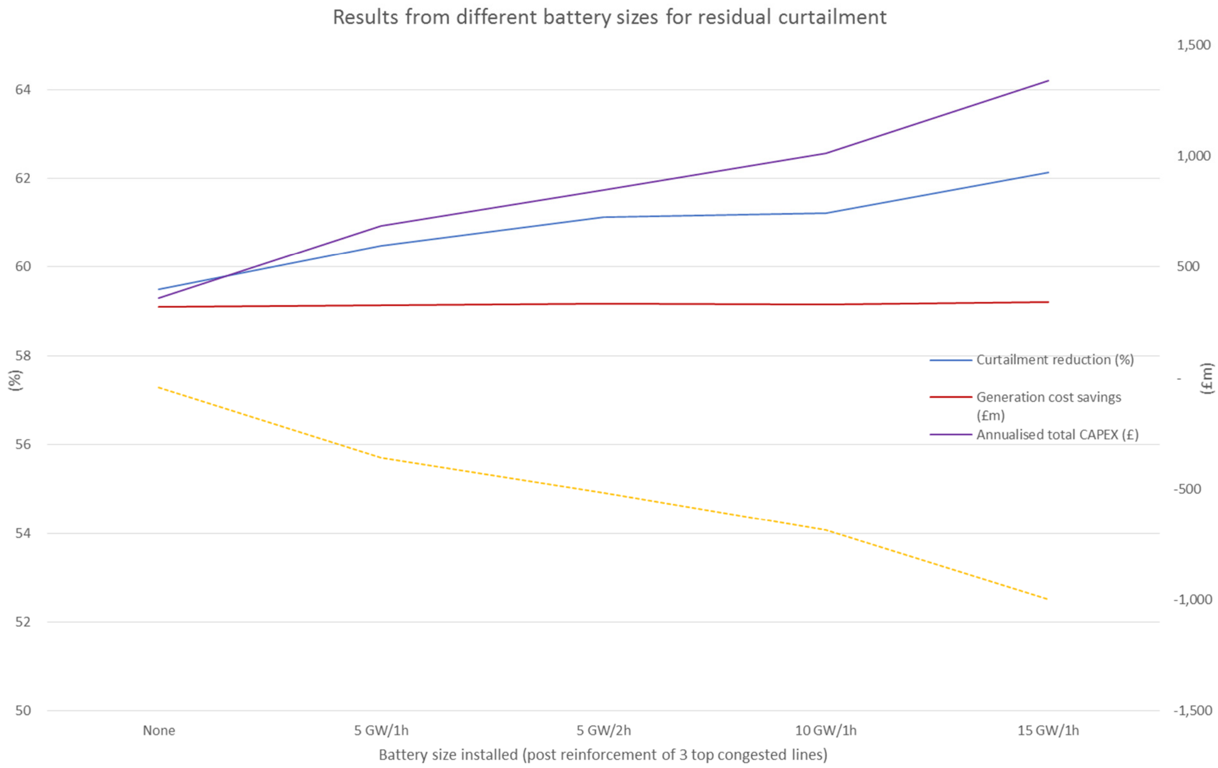


*Figure 10 – Results from different battery sizes for residual curtailment*

- **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 solution to renewable oversupply.**

## Comparison of Single and Multi Vector Options

The system benefit of power to gas solutions are compared to the single vector alternatives for the ESME modelled 2050 energy system, the generation mix of which is shown in appendix 8.

### Power-to-Hydrogen

The following table compares the total system costs for the multi vector electrolysis, single vector selective reinforcement, and “do nothing” options.

*Table 26 – CBA table for electrolysis (MV) vs transmission reinforcement (SV)*

| | Multi Vector (Electrolysis) | | | | “Do-Nothing” | Single Vector Reinforcement | |
|---|---|---|---|---|---|---|---|
| | Base Case | Leeds H21 H2 price | Low Capex | Leeds H21 H2 price & Low Capex | | Base Case (10%) | 100% |
| $H_2$ 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%** |

- **In the Base Case, selective reinforcement leads to lower total system costs and greater curtailment reduction than electrolysis; despite the availability of 23TWh zero-cost curtailed electricity, the economics of electrolysis as a means of resolving system level oversupply appear challenging due to:**
    - **Low $H_2$ price (against the power price for which single vector solutions compete).**
    - **High capital costs**
    - **The shape of the curtailment duration curve.**
- **Higher $H_2$ prices increase the capacity of electrolysers that can be economically built - the 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.**
- **Reduction in electrolyser capex has a similar effect on the total system cost; a combination of $H_2$ price increase and reduction of capex could create significant potential for electrolysis.**

**In the Base Case, transmission reinforcement is preferred to electrolysis. However, electrolysis could become viable and successfully compete with reinforcement, provided the value of $H_2$ generated reaches levels similar to those 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.**

### Power-to-Methane

Methanation is found to be NPV positive only for a negative carbon price – in which case a significant part of renewable surplus is converted to $H_2$. Single vector results are compared to negative carbon cost methanation below.

*Table 27 – CBA table for methanation (MV) vs transmission reinforcement (SV)*

| | Multi Vector (Methanation) | "Do-Nothing" | Single Vector Reinforcement | |
|---|---|---|---|---|
| | 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%** |

- **Where methanation absorbs carbon emissions, it is more cost-effective than selective reinforcement, leading to significantly lower system cost and residual curtailment, though supply of significant negative cost carbon will be difficult to find in the ESME modelled 2050 energy system.**

## Sensitivities

**The sensitivity of our results to the methanator capital costs, gas and carbon price are illustrated in the table below for zero and positive carbon prices.**

*Table 28 – Methanation Viability at Zero Carbon Price*

| | Zero Carbon Price | | Positive Carbon Price | | |
|---|---|---|---|---|---|
| | 40% lower Capex | 40% higher gas sale price | 40% lower capex | 40% higher gas sale price | Both, and low carbon price |
| Total capex (£/MWth) | **690** | 1150 | **690** | 1150 | **690** |
| Gas price (£/MWh) | 28 | **39** | 28 | **39** | **39** |
| $CO_2$ cost (£/tonne) | 0 | 0 | 545 | 545 | **50** |
| Min. economic methanator load factor | 54% | 56% | NA | NA | 48% |
| Economic methanator size (MW) | 618 | 618 | 0 | 0 | 621 |
| Renewable energy volume converted to SNG (TWh) | 5 | 5 | 0 | 0 | 5 |
| Percentage of renewable energy surplus converted to SNG (%) | 21 | 21 | 0 | 0 | 21 |
| Yearly SNG volume output (MCM) | 282 | 282 | 0 | 0 | 284 |

At zero $CO_2$ price, a capex reduction or an increase in the SNG price would increase the attractiveness of investing in methanation, with non-zero output at a 40% capex reduction or a 40% gas price increase. Both lead to conversion of 21% of the renewable curtailment into SNG.

For positive $CO_2$ price, achieving a similar level of methanation capacity as for zero cost $CO_2$, requires a combination of:

- reducing the carbon price to £50/tonne
- reducing the capex by 40%
- increasing the gas price by 40%.

- **As methanation involves further efficiency losses, it is viable only where it absorbs carbon that would otherwise be emitted, even at zero fuel cost. Smaller carbon neutral facilities might also create value if the gas price rose, or the capital costs fell, substantially.**

## Conclusions

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[44]. In that case, electrolysis leads to similar or greater total system benefit and lower residual curtailment of renewables. Electrolysis could also provide several ancillary services to the electricity market due to its flexibility and quick response to control signals, so increasing its revenues.

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 - appears significantly less economically attractive than electrolysis, due to its higher capital and operational fixed costs, and further efficiency losses. 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 renewable oversupply requires significant reduction in capital costs and/or increase in the SNG price.

[44] The current hydrogen wholesale price is around this level, see Hydrogen - Untapped Energy? (page 7)

## Applicability

The relevance of our modelling to P2G generally and the effect of model structure are discussed below.

*Table 29 – Applicability of Case Study Analysis*

| Parameter | Wider Relevance |
|---|---|
| System boundary / Hydrogen Price | **Modelled P2G production does not affect prices, as amounts are marginal this is unlikely to affect the relevance of our findings. Other markets, especially transport, may increase the price.**<br>The broader energy system is considered exogenous to the analysis, given this, we assume P2G production does not materially affect the supply and demand balance of $H_2$ or natural gas, so $H_2$ and natural gas shadow prices are fixed as originally given by each ESME set of results, and used as a proxy for the required wholesale prices. In ESME Scenario 3, 10.2 TWh of hydrogen are produced, mostly through biomass gasification (with CCS). The $H_2$ produced via electrolysis in our analysis therefore represents between 38% (in the base case) and 73% (for low capex, £50/MWh price) of the total $H_2$ production.<br>Although these represent significant volumes, production from (zero cost) renewable oversupply means electrolyser production will be less expensive than the marginal (most expensive) technologies. The sale price of hydrogen is therefore unlikely to be significantly lower than the ESME prediction; though the effect of zero marginal cost production on the market could be explored further in any future full system analysis. |
| Duration Curve | **"Smarter" business models may increase the viability of electrolysis, though we expect only around 5% of power prices to be below breakeven price.**<br>The model assumes that only surplus renewable generation that would otherwise be curtailed, is converted to $H_2$ via electrolysis. Therefore, the electrolyser does not purchase electricity from the wholesale market but only utilises the zero-cost electricity surplus |
| Electrolyser operation | **Given the hourly granularity of our modelling, the assumption of full flexibility for electrolysis is considered valid for the purposes of this study.**<br>NREL trials into polymer electrolyte membrane (PEM) and alkaline electrolysers suggest they 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)[45]. The flexibility of PEM electrolysers is also highlighted in publicly available data from ITM Power[46]. |
| Single Vector Counterfactual | **A more granular study may identify areas to target for grid reinforcement; as we consider the transmission system, the nodal structure of ESME likely captures the big picture.**<br>Single vector mitigation considered a range of plausible cases to gain a high-level understanding of the costs and benefits. A more detailed analysis of transmission reinforcement selection, and battery location and sizing, would give further insight into the cost and technical implications of single vector solutions. Other options for dealing with curtailment, e.g. DSR, might also be considered. |
| Electrolyser Provision of Ancillary Services | **At current levels, ancillary service provision fees are unlikely to "tip the scales" for P2G as a reservoir for renewable oversupply.**<br>There is considerable uncertainty around the value and market size for future grid balancing services, which are discussed in appendix 7.4.4. We find that 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. |

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

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

### 3.4.4 Barriers and Innovation Requirements

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 *D5.1 Barriers to Multi Vector Energy Supply.*

#### Availability of and Competition for Cheap Electricity

**Electrolysis is modelled as a reservoir for renewable oversupply at zero supply cost. However, other technologies that can store low cost electricity in some form (e.g. pumped hydro) may compete for this energy, and exert upward pressure on the price.**

Half hourly wholesale electricity prices will fall to near zero when instantaneous total renewable generation exceeds system level demand (though network capacities and usage costs will complicate this assessment). The extent to which supply outstrips demand – renewable generation less off-peak demand levels - will determine the amount of available free electricity. Mechanisms such as demand side management will act to reduce the frequency and severity of these events as more renewables are brought online, and few economically-plausible future hydrogen electrolysis (or other low-cost electricity) business models consider operation at zero electricity price only.

The upward pressure on low electricity prices from competing single and multi vector services is beyond the scope of this study, though we note that given the Case Study 80% efficiency and a £28/MWh hydrogen price (£1.1/kg), electrolysers run profitably only at electricity prices below £22.4/MWh – around 50% of the annual average; the ESME2PLEXOS price series is below this value 5% of the year (these do not include network use and balancing costs). We note that the ESME price - £1.1/kg is below current merchant hydrogen price.

#### $H_2$ Concentration Limits for Gas Networks

**Hydrogen blending - the injection of hydrogen into the gas grid - is constrained by the $H_2$ concentration limit, which exists to guarantee the integrity of the gas network (particularly iron mains) and appliances.**

For large-scale electrolysis using surplus energy from renewables such as wind farms, diurnal gas throughput at hydrogen injection points will define the maximum allowed volume of injected $H_2$:

Hydrogen concentration limits are informed by:

- 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.
- Specification UN ECE R 110 stipulates a limit value for hydrogen of 2% by volume for steel tanks in natural gas vehicles; the industry is however moving to Type 4 carbon fibre tanks which can accommodate hydrogen at any concentration.
- Gas turbines - most currently installed gas turbines were designed for a natural gas hydrogen fraction of 1% by volume or lower; 5% may be attainable with minor modification or tuning measures, some new or upgraded turbines will be able to cope with concentrations of up to 15% by volume.
- Gas engines - hydrogen concentration levels of no more than 2% by volume are recommended; Clarke Energy quote a hydrogen current limit of 4% by volume. Further R&D may increase this limit; concentrations up to 10% by volume may be possible for dedicated gas/hydrogen engines

with sophisticated control systems, provided the methane number[47] of the natural gas/hydrogen mixture remains above the engine minimum value.

- Analysis - many process gas chromatographs are not capable of analysing hydrogen content; Emerson have recently obtained Ofgem approval for a new gas chromatograph that can meet Ofgem accuracy requirements including hydrogen.

Most hydrogen tolerances could likely be increased with the appropriate R&D and infrastructure upgrade; 10% seems a reasonable long-term limit assumption, see Appendix 5.1 for further analysis.

Acceptable hydrogen levels in gas distribution networks will be agreed by the HSE in an amendment to the 1996 Gas Safety Management Regulations, which will be investigated in the HyDeploy project and later, once a safe level has been empirically demonstrated, in a trial on an open gas distribution network. Along with the Future Billing Methodology project, which aims to create a mechanism for local billing of gas use in line with variations in CV, this will be allow distribution level hydrogen blending without the requirement for changes to legislation.

Transmission level blending however will require the sign-off of all connected users; in particular, turbine and gas engine OEMs. This is expected to be a more complicated process; no European countries operate transmission level hydrogen blending, even where distribution level schemes have been commercialised.

We note that as per unit volume hydrogen carries only one third of the energy of methane, blending needs to be at high levels to have a meaningful impact on emissions.

Distributed hydrogen storage might alleviate short term blending limit constraints by enabling hydrogen to be stored at plant and injected into the gas grid when throughput at the injection points rises to appropriate levels. Alternatively, hydrogen might be supplied to other markets, such as the refining and steel industries, or as fuel for FCEVs.

The business case for grid injecting electrolysers as a reservoir of renewable oversupply is not compelling, and barriers remain to hydrogen blending, with R&D ongoing to determine:

- the upper limit on safe concentration levels.
- the potential for electrolysers to offer grid regulation services.

Alternative future trajectories of the generation mix, and especially the emergence of other markets for hydrogen, may offer greater opportunities to electrolysers.

[47] The Methane Number of a natural gas blend gives a measure of knock tendency; pure methane has a methane number of 100, hydrogen gas has a methane number of 0, biogas will often have a methane number over 100.

## 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 absorb excess renewable (wind, hydro and tidal) electricity and convert it to hydrogen 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 reservoir for oversupply, but also as the primary supply vector for heating energy demand – replacing natural gas. This option is being investigated at the H21 Leeds City gate project, a major innovation project that assesses in detail the implications 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[48]. 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 is 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 Data and Analysis

#### Supply Options

This Case Study examines the benefit of this multi vector configuration - comprising savings in total investment and operational cost - over the single vector approach. The single and multi vector configurations are explained below.

*Table 30 – Model Supply Configurations*

| Configuration | $H_2$ Generation |
|---|---|
| Single Vector | SMR-produced $H_2$ is transferred via a new transmission pipeline from the centre of production to the distribution network.<br><br>Salt cavern storage is used to manage both significant inter-seasonal swings observed between winter and summer (due primarily to domestic heating), and intra-day swings in demand, especially given the low SMR ramp rates[49]. |
| Multi Vector | H2 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.<br><br>Salt cavern H2 storage can be charged by both H2 production technologies, and discharged to match intra-day and inter-seasonal changes in demand. |

[48] H21 Leeds City Gate Report

[49] 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.

### Cost Minimisation and Hydrogen Generation Dispatch Optimisation Tool

Multi vector benefit has been determined by comparing the total investment and operational costs in the two cases; an optimisation model has been developed which takes as inputs the parameters below, and the technical and costs data explained in appendix 7.5.1.

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), given the charging / discharging rate
  - storage volume (capacity)
- the hourly dispatch for the production technologies and storage
- the total investment and annual operational cost

*Table 31 – Summary of Model Data Sources and Assumptions*

| Parameter | Source / Description |
|---|---|
| System Boundary | The Case Study boundary encompasses:<br>• the city's $H_2$ production and storage facilities,<br>• The $H_2$ network – and the energy demands of the connected domestic, industrial and commercial customers.<br>The broader UK energy system is considered exogenous to the analysis. |
| Total $H_2$ Demand | Total annual $H_2$ demand is 6.4TWh; based on the Leeds H21 figure for the worst-case yearly gas consumption of the Leeds conversion area. This number is derived by adjusting measure 2013 demand to the coldest average temperatures observed in the area in the last 30 years). |
| Demand to Supply Matching | Demand profile derivation is discussed in appendix 7.5.2. Our optimisation model ensures sufficient $H_2$ generation and storage capacity are built to satisfy hourly demand. Total generation and storage capacity must also be able to supply up to 1-in-20 peak demand, taken as 3,180MW based on the Leeds H21 project report. |
| Gas and Power Prices | Natural gas and electricity price profiles (along with other variable costs) determine the short-run marginal cost of producing $H_2$ using SMR and electrolysis, and thus the optimal sizing of these technologies. Hourly 2050 electricity and gas prices are as in the Case Study above, these are shown in Figure 22 in 7.5.3; the average electricity price is £47/MWh, natural gas is costed at its ESME shadow price of £28/MWh. |

### 3.5.3 Multi Vector Benefit

Results for the single and multi vector configurations are presented in the table below.

*Table 32 – Base Case Results*

| Parameter | 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) | - | - |

- **$H_2$ demand is met by SMR and $H_2$ storage both in single and multi vector scenarios, i.e., building electrolysis provides no system benefit.**

To determine conditions under which the multi vector configuration provides some system benefit we have investigated a number of sensitivities.

#### Sensitivities

#### Electrolyser Capital Cost

The following table shows two examples of electrolysis cost reduction.

*Table 33 – Sensitivity of Results to Electrolyser Capex*

| | Sensitivity: 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% |

- **Capex alone does not have a material impact on the solution; even an extreme 70% reduction from the ETI's 2050 projection leads to low levels of electrolysis commissioning, at almost zero cost saving.**

### Sensitivity to Electricity Prices

Electricity prices - effectively the electrolyser's fuel price – average £47/MWh in 2050. We have investigated the sensitivity of the solution to several price scenarios[50], the results for the different price time-series are below.

*Table 34 – Sensitivity of Results to Electricity Prices*

| | Sensitivity: 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% |

- **We find the multi vector solution could provide benefit at electricity prices significantly lower than the projections for 2050 in the Base Case, at electricity prices reduced by 45% - to an average of £27/MWh - the saving is around £6m, corresponding to a reduction of approximately 1.6% total annual cost.**
  - **The more the average electricity price is reduced, the more electrolysers are built, 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 competes not only with SMR to match 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.

[50] 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.

### Storage Minimum Discharge Time (Power to Volume Constraint)

Therefore, 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. 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 is shown in the table below:

*Table 35 – 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% |

- **We find that as we increase the discharge time:**
  - **Total single vector $H_2$ storage total volume also increases, 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 multi vector benefit - larger levels of electrolysis are built to replace diurnal storage.**
  - **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; where access to the appropriate geology for $H_2$ storage is limited - there may be scope for electrolysers to provide some of the required flexibility.**

## Conclusion

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, electrolysis remains a marginal contributor at most to hydrogen for heat networks. This agrees with the assessment of the

H21 report. This is however highly dependent on the commercialisation at scale of CCS, without which carbon emissions of unabated SMR may rule this technology out.

### 3.5.4 Barriers and Innovation Requirements

Here we focus only on the issues associated with the multi vector system including power-to-gas. The Leeds H21 project has provided a 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.

#### Availability of Low Cost Electricity

**Electrolysis is potentially viable as a $H_2$ network supply option only in areas where low price electricity is available.**

A potential power source for electrolysis is renewable generation that would otherwise be curtailed, though as shown in Case Study 4 the duration curve of renewable oversupply means an electrolyser sized to achieve an economic load factor produces little hydrogen annually. Electrolyser economics might be improved through the provision of grid services; both alkaline and (particularly) PEM electrolysers can change their output rapidly in response to control signals and can therefore provide both reserve and response services, though the potential size of the market for grid services on timeframes consistent with conversion of the gas grid to hydrogen (or the large-scale adoption of hydrogen fuelled vehicles) is necessarily uncertain.

As above, electrolysers may therefore be of greater system value near renewable generators on weak or constrained grids, but raising the cost of heating fuel is likely to be politically unpopular. A study on the size of the future balancing services market, allowing for the significant evolution expected in the power sector, would inform assessments of the likely role for electrolysers in the energy system.

#### Policy Uncertainty

**There is no concerted policy driving a transition to hydrogen for heat, and no low-carbon heat incentive for electrolysers.**

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 (many of these issues are covered in detail elsewhere, for example the Leeds H21 report and CCC report on Future Regulation of the UK Gas Grid[51]).

**A co-ordinated planning process is required to integrate the use of electrolysers and SMRs within a hydrogen network.**

Broadly speaking, the presence of an electrolyser supplying a hydrogen distribution network is analogous to a biomethane plant injecting into the current gas grid. In this case the commercial arrangements are reasonably straightforward, with the distributed gas producer entering into bilateral agreements with the gas network operator and a shipper – the Network Entry Agreement and gas sale respectively. In the case that the electrolyser is a more integrated part of network operation, i.e. it is a source of supply but also acts as a substitute for transmission capacity and diurnal storage, there is an increased level of complexity that may be better managed by a more regulated approach.

[51] Future regulation of the UK gas grid, Frontier Economics and Aqua Consultants, CCC, June 2016, www.theccc.org.uk/wp-content/uploads/2016/10/Future-Regulationof-the-Gas-Grid.pdf

## 3.6 Case 6a: Power to heat – District Heating

### 3.6.1 Case Introduction

#### Context

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.

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.

#### Aims

The Case Study considers two separate systems:

1. A town in which domestic, and industrial and commercial space and water heating is supplied via a heat pump-based district heating network, using electricity from the grid.
2. 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 a local town. When wind generation exceeds the town's demand, surplus can be exported to the grid, causing reverse power flow on the transformer's windings.

The goal of this Case Study is to understand:

a. whether there is a total system cost benefit in bringing wind farms and district heating systems together, relative to the single vector optimised options of substation reinforcement and wind generation curtailment

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).

An overview geospatial analysis for potential locations can be found in appendix 7.6.1.

### 3.6.2 Data and Analysis

#### Model Components

The model includes the two following systems, which may be connected for multi vector operation.

*Table 36 – Model Components*

| Parameter | Source / Description |
|---|---|
| Heat Network | Supplies the equivalent of 1% Leeds's total heating demand (considered in Case Study 5) using a central heat pump supported by a thermal storage system. The heat pump draws power from the grid, converting it to heat as given by its coefficient of performance (CoP). Storage allows the heat pump to produce heat during period of low electrical prices, to be dispatched later during periods of higher prices.<br><br>As in the previous case, the heat network must be capable of meeting a 1-in-20 cold year peak demand through the combined use of the heat pump and the thermal storage. |
| Wind Farm | A wind farm with a capacity between 7.5MW and 30MW, connected to a primary distribution substation. |

The parallel single vector, and joined multi vector, systems are then optimised based on:

- the electricity price timeseries (with perfect foresight)
- the cost of heat pump and storage technologies
- the cost of substation upgrade

#### Cost Minimisation and Heat Pump/Wind Farm Optimisation Tool

To assess the multi vector benefit, single and multi vector costs have been determined using an optimisation tool, which takes as inputs the data below and in appendix 7.6.3. The model solves a linear optimisation problem which minimises the total cost subject to energy balance and technical constraints.

*Table 37 – Model Components*

| Parameter | Source / Description |
|---|---|
| Total Heat Demand | To determine total district heating thermal supply, gas demand from Case Study 5 is adjusted by an average conversion efficiency of gas boilers (80%, as per ESME V4.1 database), given a typical yearly thermal demand of 51 GWh. |
| Heat Demand - Hourly Profile | The heat network hourly demand profile is derived from Carbon Trust micro-CHP field trials data, as in the previous Study. As in that Study, the model ensures that the heat pump capacity and heat storage deliverability can meet hourly demand for a 1-in-20 peak winter. The maximum hourly heat demand in a typical year is 16 MW, peak heat demand for a 1-in-20 winter is calculated as 25MW, following the methodology in the H21 report. |
| Substation | The wind farm is connected to a substation - modelled as a single 5MW transformer which supplies a nearby town. Wind farm export to the grid is limited by the transformer's reverse power flow capacity, which we assume to be 75% of its rating. |
| Electricity Prices | We use the hourly wholesale electricity price timeseries used in Case Studies 4 and 5. The electricity prices seen by each system component vary as follows:<br>• Wind generation supplied to the town connected to the same distribution substation is sold at the wholesale power price<br>• Wind generation exported across the system boundary is sold at 96% of the wholesale electricity price, accounting for distribution network losses of 4%.<br>• 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[52]. As a result, using electricity directly from the wind farm leads to a reduction of the total system costs as these losses are avoided. |
| Substation Electricity Demand Hourly Profile | The shape of the substation hourly electricity demand is based on an anonymised substation load profile 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. |
| Hourly Wind Load Factors | Based on 2008 data for the Yorkshire and Humber region. |
| 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. |

[52] 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.

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)

### 3.6.3 Case Study Analysis

Results for the single and multi vector configurations are shown in the table below.

*Table 38 – Base Case results*

| Parameter | 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% |

- **Wind farm generation exceeds substation demand 8% of the time, leading to 760MWh of curtailed electricity (4% of total). The costs incurred by curtailing generation, however, are insufficient to justify the cost of upgrading the transformer.**

- **Curtailment is mitigated by exporting generation to the district heating system; 70% of curtailment are absorbed with total cost savings of around to 6% of the combined costs of both single vector systems (the system benefit comprises mainly the avoided transmission and distribution network costs incurred where heat pump electricity is imported from the transmission grid). These savings justify building an interconnecting cable only 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, we have investigated several sensitivities.

## Sensitivities

### Sensitivity to Wind Farm Size

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 39 – 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%) |

- **Where transformer upgrade is required to cost effectively accommodate wind farm generation (as in the 30MW case), connection to a district heating scheme can reduce the size of the upgrade, leading to higher multi vector benefit. Even in this case however, the savings are equivalent to the build cost of a few km of connecting cable.**

### Sensitivity to Heating Demand Levels

We next consider how our results vary with the district heating scheme size; below we present the results considering 50%, 75%, 200% and 1000% of the original heating demand.

*Table 40 – 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[53] |
| 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% |

- **Wind farm curtailment is reduced as the size of the heat network increases; the district heating system can absorb higher levels of wind generation. The multi vector configuration becomes more favourable as the size of the district heating system increases, though the maximum multi vector benefit remains insufficient to justify more than a few km of HV cable.**

[53] This is the minimum level of curtailment, and corresponds to times of zero power prices, when there is no value in absorbing wind farm, rather than grid, power.

### Sensitivity to Pass-Through Charges

Although we have considered system value above, it is interesting to understand the perspectives of individual parties, e.g. private owners of the heat network and wind farm. 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 network use margin, some of which could be avoided if the district heating system was supplied by the wind farm via a private wire.

Operator savings have been investigated by varying the pass-through margin on to the wholesale price (the operator saving margin is effectively 0% in the Base Case scenario, results are shown below for values of 20%, 50% and 100%)

*Table 41 – 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%) |

- **Large pass through charges create significant (operator) multi vector benefit; the greater the charges the more savings the multi vector configuration creates, and therefore the more incentive the system owner has to invest in an interconnecting cable at greater distances between the two systems. Private wire connections between extant wind farms and heating schemes do not create substantial societal benefit, but there may be an incentive for private operators to invest in such connections.**

### 3.6.4 Barriers and Innovation Requirements

Barriers to the private wire connection of renewable generators and large heat pumps are minimal; the broader case for renewables to heat for networks, and existing trials, are discussed in appendix 7.6.1

## 3.7 Case 6b: Power to heat – Smart Electric Thermal Storage (SETS)

### 3.7.1 Introduction

#### Context

Around 10%[54] 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, 2.4m are electrically heated[55106]. 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.[56]

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 thermoelectric 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[57] - 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 to 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 investigate the ability of 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 – the potential scale and value of grid regulation are discussed in appendix 7.7.1.
3. Lower the costs of low-carbon, off-grid heating.

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.

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[54] Sub-national estimates of households not connected to the gas network
[55] United Kingdom Housing Energy Fact File 2013
[56] About Local Energy Economies: The potential for Scotland, CES 2014
[57] Energy consumption in the UK

### 3.7.2 Data and Analysis

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:

*Table 42 – Modelled Scenarios - Generation and Constraint Sizes*

| Parameter | Scenario | | |
|---|---|---|---|
| | Hydro (Scottish Islands) | Wind (Scottish Borders) | Solar (West Country) |
| Generator Power | 180kW | 12MW | 4MW |
| Export Constraint | 50kW | 4MW | 2MW |
| Homes on Constraint side | 100 | 4,000 | 2,000 |
| Storage Heater Homes | 85 | 4,000 | 2,000 |
| Electric Boiler Homes | 15 | 0 | 0 |

*Table 43 – Summary of Model Data Sources and Assumptions*

| Parameters | | Source / Description |
|---|---|---|
| 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. Space heat demand totals are 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[58]. |
| Electrical Heating and Storage | Electric boilers | For space heating and DHW, sized to 1,000 run hours for each housing type. 180 litre hot water tanks determine the storable energy. |
| | Storage heaters | These supply the space and hot water demands at economy tariff homes respectively, and are sized to run for 7 hours per 24 for half the year (1,275 hours). Storage levels are determined by maximum daily demand. |
| | Immersion heaters | |
| Appliance Power Demand | | Demand profiles are taken from Element primary substation data, (also used in Case Study 1). |
| Power prices | | Taken from 2020 ESME High Decarbonisation Scenario, at an average wholesale price of £39/MWh. (Our model not optimised for prices or forecast demand, so these are used for value determination only). |
| Environmental Value | | A price of £45/tonne, and an average grid intensity of 0.255 tonnes $CO_2$/MWh are taken from BEIS Central 2020 projections, and used to calculate the environmental benefit. |
| Hourly Generation Data | Hydro | Taken from UK level Gridwatch Data, scaled to plant capacity |
| | Wind | |
| | Solar | Taken from UK *PVsyst*[59] Data |

[58] 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.

[59] PVsyst is a software package which calculates time series generation for PV arrays.

### 3.7.3 Multi Vector Benefit

For each of the scenarios 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).

Parameters for modelled scenario are given below.

*Table 44 – Model Scenario Parameters*

| Parameter | Hydro | Wind | Solar |
|---|---|---|---|
| Generator Nameplate | 180kW | 12MW | 4MW |
| Export Limit | 50kW | 4MW | 1MW |
| Generation Load Factor | 37% | 32% | 24% |
| Peak Thermal Demand | 280kW | 6,400kW | 2,860kW |
| Peak Non-Thermal Power Demand | 50kW | 1,050kW | 525kW |
| Useful Heat Fraction | 70% | 50% | 49% |

#### Useful Heat Fraction

Of the heat that is stored through demand management some will be dissipated – typically more than usual for storage heaters, especially where substantial heat is stored during the summer. The customer value will therefore not reflect the full price of the electricity. We therefore report, the total generation value, and that value scaled by the Useful Heat Fraction; the scaled and unscaled values represent lower and upper bounds on the smart multi vector value respectively.

#### Smart Value

In this Case Study, smart demand matching comprises only turning electric heaters up when there is capacity above their normal operation; no forecasting or modification of normal operation is included. Consequently, a more sophisticated demand matching platform may create more value than we model here. This implementation allows us to differentiate between total value – renewable generation absorbed by electric heaters – and smart value – generation absorbed as a result of smart demand management (these can also be thought of as generator value created by unmanaged and managed electric heaters respectively).

#### Threshold Value

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.

### SETS Value

The per kW values of demand matching through SETS are shown below for the three scenarios.

*Table 45 – Annual per kW SETS Value (£/kW)*

| Parameter | Hydro | | Wind | | Solar | |
|---|---|---|---|---|---|---|
| | Total | Smart Value | Total | Smart Value | Total | Smart Value |
| Total Solution Value | 47.04 | 7.16 | 73.09 | 45.85 | 51.20 | 44.92 |
| Total Solution Value Scaled by Useful Heat Fraction | 33.10 | 5.04 | 35.72 | 22.41 | 24.88 | 21.83 |

- **SETS value of storage and immersion heaters is between £20/MWh and £50/MWh; similar to system level value of frequency response provision. Control systems and aggregation platforms which allow the provision of both services, may recoup their control and monitoring system costs more rapidly.**

*Table 46 – Absorption of Renewable Oversupply*

| Parameter | Hydro | Wind | Solar |
|---|---|---|---|
| Generator Capacity (kW) | 180 | 12,000 | 4,000 |
| SETS Capacity (kW) | 280 | 6,400 | 2,860 |
| Generation (MWh) | 585 | 33,343 | 8,266 |
| Absorbed by SETS (MWh) | 71 | 6,748 | 1,724 |
| SETS “Load Factor” | 12% | 20% | 21% |
| Curtailment (MWh) | 21 | 4,492 | 2,022 |
| Curtailed Share | 4% | 13% | 24% |

*Table 47 – Annual Per User SETS Value (£/User)*

| Parameter | Hydro | | Wind | | Solar | |
|---|---|---|---|---|---|---|
| | Total | Smart Value | Total | Smart Value | Total | Smart Value |
| Total Solution Value | 149.81 | 22.79 | 129.74 | 81.38 | 75.52 | 66.25 |
| Total Solution Value Scaled by Useful Heat Fraction | 105.41 | 16.04 | 63.40 | 39.77 | 36.69 | 32.19 |

- **At £20 per user per year[60], the annual costs of monitoring and telemetry required to enable smart management of thermal demand can be recouped, though insufficient value may remain to incentivise customer participation once this margin is shared between the aggregator and generator. The SSE Real Value Project offers a participation fee of €10 per household per month, these levels are unlikely to be supported by the system value of SETS.**
- **Electric boilers dominate in the Hydro scenario; the per kW value of SETS provision through these is lower than for storage heaters, and they absorb smaller amounts of curtailment due to their lower storage capacities. The user incentive for boilers - between £15/year and £25/year – may still be sufficient to allow these to participate in SETS provision, especially for community schemes where costs may be reduced through economies of scale.**
- **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. For large clusters of electrically heated homes, there may be sufficient value to develop SETS as a means of avoiding curtailment of PV oversupply, particularly if platform costs are low and intelligent forecasting of demand can increase the utilisation of stored heat.**
- **Even at £100/user/year – toward the upper end of our results - the value of SETS is likely insufficient to pay for new storage heaters[61]. The value may however encourage installation of smart heaters in new build homes or upgrade of existing units. As heaters have a lifetime of around 15 years, by 2030 at least 15GW of domestic thermal demand could be demand manageable, much of it in isolated grid areas. As this value accrues to generators, commercial models to share this value with homeowners replacing their heating systems, or new build developers deciding energy solutions for their developments, will need to be developed.**

## Environmental Value

By absorbing renewable supply, SETS avoids having to import power later, potentially at non-zero carbon intensity. We estimate the displaced emissions, and the value, in line with the BEIS carbon price and average power carbon intensity projections for 2020, shown below.

*Table 48 – 2020 SETS Environmental Value (Fraction of SETS value)*

| | Hydro | Wind | Solar |
|---|---|---|---|
| Additional Environmental Value | 34% | 23% | 27% |

[60] Where SETS is provided by buildings with dual time meters and legacy electrical heaters, further metering and telemetry will be required, with costs well above this value.

[61] Between £1,000 and £3,000 depending on building size, thermal efficiency and new/existing stock.

- **The environmental value of SETS might increase its value by around 20-35%. A low-carbon heat subsidy in line with the BEIS Price and Carbon Intensity projections, increases the SETS value sufficiently to increase the lower bound of per user value to above the £20 control system cost.**

## 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.

*Table 49 – Useful Heat Fractions by Generation Type*

| 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 50 – 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.

## Conclusions

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. 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 heated electrically, rather than using oil. 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.

## 3.7.4 Barriers and Innovation Requirements

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 *D5.1 Barriers to Multi Vector Energy Supply.*

### Sharing Value with Scheme Participants

**Management of domestic thermal demand to balance renewable energy supply may lead to heaters being run at peak, rather than off-peak, times – increasing consumer energy bills.**

A mechanism is required to ensure participation is attractive to scheme participants, considering that demand management is likely to be implemented as direct control by an aggregator, rather than purely based on price signals, to ensure the required 'firm' DSM response from a potentially limited number of customers. In particular, commercial arrangements must ensure that consumers benefit (or at the very least, see no total cost increases) as a result of SETS participation.

Aggregators and home energy control firms are beginning to offer innovative heating solutions to DNOs (or DNOs and suppliers jointly), mainly involving the use of immersion elements for hot water supply - of the current trials looking at aggregation of smart demand, most have used a flat fee to encourage participation, with SSE paying participants in the Real Value scheme around € 10 each month.

Potential solutions include:

- **A customer rebate** – customers could be provided a rebate for participation in the scheme. This would be relatively simple to implement, and not necessarily require a change in their tariff.
- **Local time of use tariff** – Suppliers could offer a time-varying tariff, with lower electrical prices at times of high renewable generation. This tariff would ensure that consumers benefit from the management of their demand (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 the consumers based on half-hourly consumption data and a time varying tariff, ensuring the consumers benefit from demand management. The renewable generation and aggregated demand are pooled behind the virtual MPAN and the energy company then 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 (potentially 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, consumers could still be billed by the electricity supplier, with a lower tariff offered to scheme participants (funded by a share of the increased generator GDUoS).

## Use of Existing Networks to Match Generation to Local Demand

**Systems that match local supply and demand currently realise very little of the system level benefit they create.**

Grid balancing is managed at the national 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. There are currently no structural incentives to match local generation and demand, though local matching can assist supplier balancing (reduced BSUoS), reduce network costs (TUoS and DUoS) and line losses; these embedded benefits can then be passed on by the supplier.

**Networks Preference cannot be given to 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 planning permission for these can be difficult to obtain. Energy Local and SSE's Virtual Private Wire are examples of schemes under which small portions of existing grids can be used to match local demand and generation.

## 3.8 Case 7: Energy-from-Waste to Electricity and Biogas

### 3.8.1 Case Introduction

#### Context

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.

#### Aims

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. 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 (we focus on 2050, as an illustrative snapshot year).

### 3.8.2 Data and Analysis

#### Single and Multi Vector Configurations

Two EfW systems are studied:

- Anaerobic Digestion (AD)
- 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 to assess multi vector value, we must demonstrate benefit over both single vector configurations).

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 via 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. 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 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[62]. For this reason, this study envisages that gas offtake for the CHP plant occurs after the $CO_2$ capture step, which is therefore common to both gas injection and CHP mode.

[62] Information obtained from Progressive Energy on Waste Gasification plants

The ability to export to the gas grid or burn gas in a CHP engine presents the option for the EfW facility operator 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.

Whether there is multi vector benefit depends on this option value relative 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)

## Modelling

In this Case Study, we add a probabilistic element to the electricity and gas price data used in previous Studies to create 100 pairs of coupled gas and power prices; this is discussed in appendix 7.8.1.

Across these possible price pairs, the Case Study model calculates:

- 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.

This is discussed in detail in appendix 7.8.2.

## 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.

Data on these are shown in appendix 7.8.3. and 7.8.4.

### 3.8.3 Case Study Analysis

#### 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.

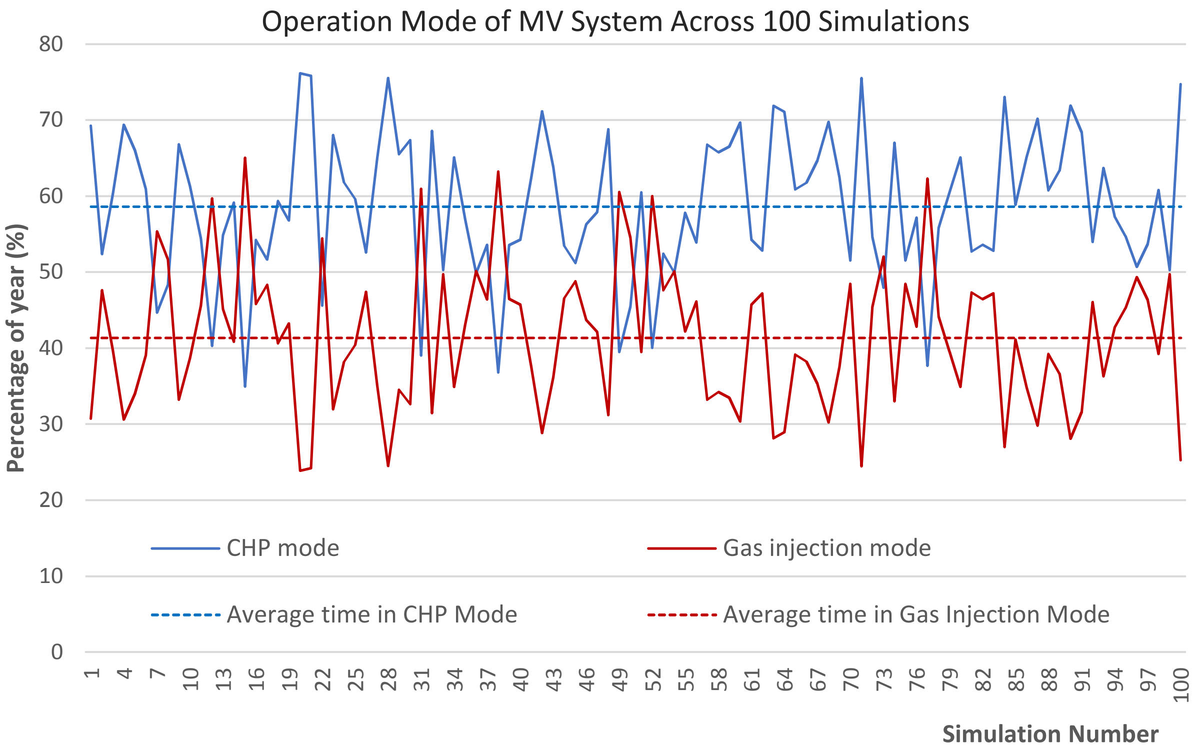


*Figure 11 – Multi vector plant operation across 100 simulations*

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 51 – Base Case Results for AD Plant*

| Parameter | 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**

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. We have therefore investigated the sensitivity of the results on this parameter.

*Table 52 – Effect of Power and Gas Price Correlation on Multi Vector Benefit*

| Gas and Power Price Correlation | SV 1 CHP mode | MV vs SV 1 | SV 2 Gas injection mode | MV vs SV 2 |
|---|---|---|---|---|
| Low (6%[63]) | - | 52 | - | 11 |
| Central (15%) | - | 46 | - | 6 |
| High (94%) | - | -75 | - | -117 |

[63] Specific correlation values were determined by the model architecture.

When correlation is reduced, the multi vector benefit for both single vector plants increases, with both systems having a higher increase in revenues and profit margin of those revenues. Conversely, where gas prices follow the movement of electricity prices more closely, multi vector option value falls significantly. Multi vector benefit rises as electricity and gas prices become uncoupled, and falls (to below zero) when they are more tightly linked.

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.

### 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.

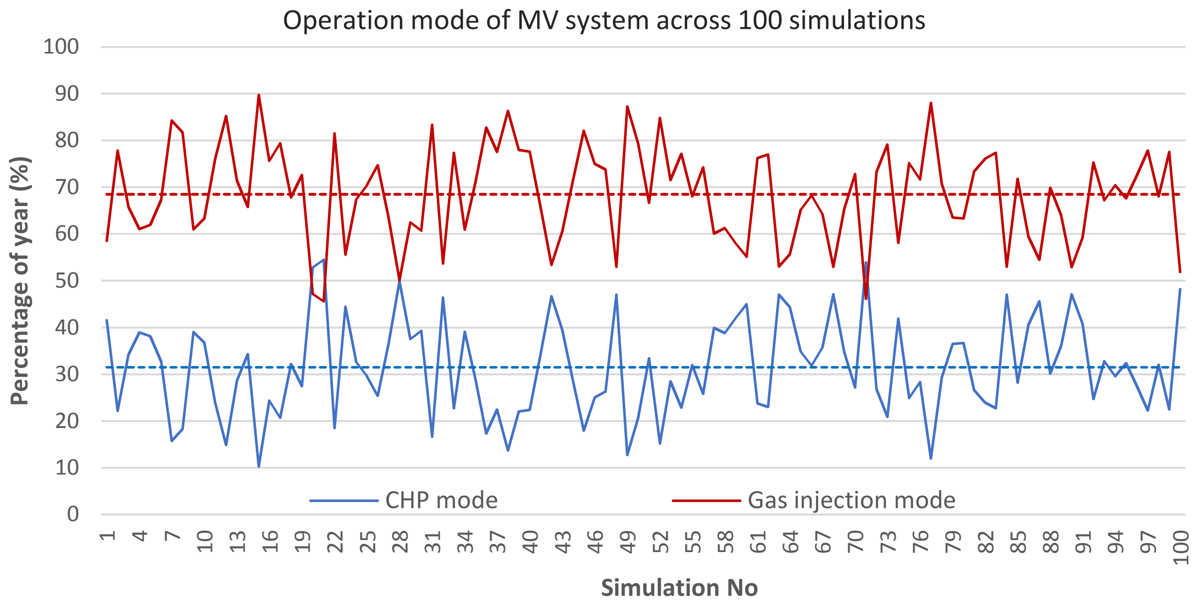


*Figure 12 – Multi vector plant operation across 100 simulations in Base Case*

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 78).

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 53 – Base Case Results for Waste Gasification Plant*

| Parameter | 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 a gas injecting waste gasification plant sees a positive return from CHP installation, occurs at mean electricity prices 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[64]. 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.

[64] Assuming CHP thermal efficiency is around twice the electric efficiency.

*Table 54 – Sensitivity Results from Increasing Average Electricity Prices*

| Parameter | 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.**

**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. 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.

*Table 55 – Sensitivity Results from Lowering Correlation*

| Parameter | 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 |

### 3.8.4 Conclusions

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 EfW plant CHP upgrade is sensitive to the value of the heat produced by the CHP. Upgrade, i.e. addition of a CHP system, may be viable even at a modest price, but in many cases the locations of gasification and AD plants will be remote from centres of heat demand, due to the nature of the plants and attendant planning issues.

### 3.8.5 Barriers and Innovation Requirements

Significant challenges associated with the transition to multi vector operation have been collated through consultation with industry stakeholders and other experts, and are summarised below. More detailed analysis is provided in the accompanying report *D5.1 Barriers to Multi Vector Energy Supply.*

#### Competition to Supply High Price Electricity

**The benefit of adding a CHP engine to an AD or gasification plant comprises electricity sales at times of high electricity prices[65]. Gas turbines connected to the network (which are also likely to be more electrically efficient) are to compete with CHP generation for power sales as prices rise; exerting downward pressure on the power price.**

Unless the effective price of heat is high, or there is some local premium for electricity price, the LCOE of a new biogas turbine will be undercut by existing gas generators. Carbon price will affect this balance; high carbon prices will lower the returns of turbines burning natural gas, though these will also incentivise EfW gas injection rather than power export. From a system perspective, as carbon prices

[65] And potentially heat sales, though the price of heat will be lower, and vary significantly less

rise it is increasingly preferable that green gas is blended in to the grid and – where it is used for power generation – is burned in the most efficient available turbines. High carbon prices are therefore likely to encourage the single vector solution – biogas injection into the grid – rather than multi vector operation including (power-only) export in a relatively inefficient CHP engine.

It is instructive to compare this Case Study and Case Study 2, where we found operator value may be created in upgrading a CHP network to include a heat pump powered by CHP cogeneration. This value however comprises mainly the avoided use of system charges for the electric grid, which represent an appreciable fraction of the total cost of power import; the levy on moving gas across the NTS, in this case from the EfW plant to the nearest gas turbine, is a small fraction of the price of gas.

Subsidy may also help this, but typically EfW subsidies incentivise CHP (rather than power only export).

The degree of competition will be informed by use of system charges, e.g. if GDUoS fees are high local generation receives a premium, which may encourage EfW power export.

## Propanation

**Grid injection of biogas currently requires propane blending to increase its Wobbe Number (WN) and/or calorific value (CV) to the required levels.**

The Gas Safety Management Regulations[66] (GSMR) specify the operational Wobbe Number[67] range for grid gas. Biomethane from AD and bioSNG from gasification have lower Wobbe Numbers than most UK natural gas, though typically there are no operational barriers to grid injection.

However, the Flow Weighted Average Calorific Value (FWACV) regime which governs gas billing stipulates that the CV of billed gas cannot be more than 1MJ/m$^3$ above the minimum CV of gas injected into the Local Distribution Zone (LDZ). As the calorific value of biomethane and bioSNG are lower – at 36MJ/m$^3$ - than typical UK grid gas mixes– at around 39.5MJ/m$^3$ – grid injection of biomethane and bioSNG requires blending with a gas of higher volumetric enthalpy; propane is typically used. Propanation represents an additional cost to the biomethane producer, which depends on the molecular composition of the biogas and the FWACV of the LDZ. An Element Energy study on distributed gas sources[68] found that propanation costs might represent up to 10% of revenues, at 0.3p/kWh injected.

We note that this is a function of the gas charging methodology, rather than a safety concern, and that the ongoing National Grid Future Billing Methodology project is considering means of measuring and billing gas CV on a more local basis.

[66] A Guide to the Gas Safety (Management) Regulations 1996

[67] The Wobbe Number, or Index, specifies the interchangeability of fuel gases.

[68] To be published shortly.

# 4 Multi Vector Systems – Implications for Today's Networks

In the following section, we discuss the implications of multi vector supply for the current energy networks. In particular we consider:

- The challenges that implementing multi vector systems present to the existing network businesses
- The benefits that multi vector systems could deliver, in terms of meeting the networks' operational objectives.

## 4.1 Technical and operational challenges

The consideration of barriers and innovation opportunities for each of the multi vector case studies has identified a number of technical and operational challenges for the existing networks, principally the electricity and gas networks. The key challenges are summarised in the table below. Many of these issues are explored in greater detail in report *D3.1 – Assessment of Local Cases* and also in *D5.1 – Barriers to Multi Vector Integration*.

*Table 56 – Summary of the key technical and operational issues for current network operators in developing multi vector energy systems*

| MV system | Technical issues | Operational / investment planning issues |
|---|---|---|
| **Hybrid Heating** | • **LV monitoring –** currently there is little monitoring of the electrical networks at LV. Monitoring at LV feeder level would allow demand management of hybrid systems to be optimised.<br>• **DSM platform** – A means of reliably shifting heat load off the electrical network onto gas at times of electrical system stress is required. This could be price based, e.g. ToU tariffs, although direct load control is likely to provide a firmer response.<br>• **Gas network ramp rates** – Rapid ramp rates of gas demand on low pressure gas networks will need to be managed to avoid excessive pressure drops. This could be managed by the DSM system, to ensure the transition of load onto the gas network is phased to avoid very high ramp rates. Gas storage at MP/LP levels could also be a solution, if LP pressure drops are found to necessitate this. | • **Joint investment planning** – Greater coordination between electricity and gas DNOs is likely to be required to ensure effective planning of investment in the networks in areas of high hybrid heating system deployment.<br>• **Gas network cost recovery** – Changes to the regulatory model for gas network cost recovery may be required due to the reduced gas consumption, both to ensure investment in the networks and to spread costs fairly between HHP and remaining gas customers (e.g. greater component of capacity-based charge). |
| **Multi vector DH** | • The key technical challenge associated with a multi vector CHP and heat pump energy centre is likely to be heat management. As the CHP operates to power the heat pump both units simultaneously provide heat and hence will need to be appropriately sized to avoid heat rejection. The heat supplied by the two units are likely to be at different temperatures, which will also have implications for hydraulic design of the energy centre and heat network operating temperatures. | • **Real-time price optimisation** – To maximise the benefit from a multi vector energy centre, the scheme operator will require access to real-time varying prices for electricity (for buying and selling power) and gas, such that plant despatch can be optimised accordingly. It is not typically the case that CHP generators on the scale relevant to local heat networks would sell power on the wholesale market, instead operators tend to enter into a power purchase agreement with a supplier, based on a flat price for exported power. |

| | | |
|---|---|---|
| **Power to Gas** | • **Gas blending limits** – the major current constraint on hydrogen injection into the gas network is the $H_2$ concentration limits specified in GS(M)R (1% by volume). The potential to increase this limit is currently being explored in detail in the HyDeploy project.<br>• Associated with the above, gas network monitoring downstream of injection will be required, to ensure blending limit compliance<br>• Even with an increased $H_2$ blending limit (say 10 to 20%), site selection for gas grid injection may still be constrained, particularly for large electrolysers (i.e. to parts of the network with sufficient natural gas throughput)<br>• **Improved forecasting of RES curtailment** - Near term forecasting tools to predict times of generator curtailment will be required to allow SO / DSO to take action, e.g. dispatch electrolysers, and to notify gas transporters and shippers that $H_2$ injection will take place. | • **Transmission and distribution network sharing of flexible resource** - RES oversupply potentially causes issues at distribution and / or transmission level. The DNO (or DSO) and system operator (SO) may want to contract distribution network connected electrolysers to manage particular network issues or, in the case of the SO to provide ancillary services. This may be via an active network management system run by the DNO/DSO, or there could be a local market for flexibility, with appropriate prioritisation rules. Options for sharing of flexible demand and generation resources between the DNO and SO are being explored in the NGET/UKPN project TDI2.0.<br>• **Gas network balancing** – The intermittent nature of gas injection based on renewables curtailment may necessitate greater on-the-day gas balancing actions by the gas system SO. Typically gas shippers can face penal prices when the SO takes on-the-day actions to ensure system balance, which may not be appropriate where balancing actions are needed due to power-to-gas injection.<br>• A communication system will be required to provide NGGT and gas shippers notification of instructions for electrolysers to run. |
| **Grid-H2 for H2 networks** | • **Electrolyser grid impacts** – The Aberdeen electrolyser trials[69] found that electrolysers can have a significant impact on network power factor, which may necessitate corrective actions. Electrolysers could also constitute a large demand on the distribution network, which may present issues in demand constrained areas or attract high connection charges if reinforcements are required. Electrolysers may be able to modulate to operate within demand constraints to avoid the need for such reinforcement. | • **Commercial and operational framework** - the co-existence of SMR and electrolysis as H2 supplies to the network will require a process to manage their despatch and a corresponding commercial framework. This could be a liberalised market for $H_2$ supply or a command and control approach, where a manging entity coordinates dispatch of production plant. Coordinating the despatch of $H_2$ generating plant may be further complicated if the electrolyser is providing additional grid-balancing services or is part of an ANM system. |
| **Power to Heat** | • There seem to be few technical issue associated with a constrained wind farm providing power to a heat pump (or electric boiler) at times of curtailment, i.e. beyond the typical issues associated with controlling generators within an ANM system. | • There are few novel operational / investment planning issues – a bilateral contract between the DH operator and wind generator for power purchase will be required (the wind generator may need to act as licence exempt supplier in order to supply electricity to the heat network scheme)<br>• The Case Study considers power-to-heat as a means of avoiding curtailment due to a network constraint. Other studies of power-to-heat have focussed on the potential to utilise surplus renewable power, particularly in Denmark and Germany. However, despite the large technical potential for surplus |

[69] Impact of electrolysers on distribution networks, part of the Aberdeen Hydrogen Project, SSEN, November 2016

| | | |
|---|---|---|
| | | renewables in these markets to meet thermal demands, power-to-heat has been found uneconomic due to grid charges, policy costs and taxes. |
| **Smart thermal energy storage (SETS)** | • **Sophisticated ANM system** – the ANM system is required to manage generator constraints and dispatchable thermal loads, while ensuring occupant comfort. Such systems already being trialled, e.g. in the ACCESS project on the Isle of Mull.<br>• The managed demand might also provide further ancillary services, such as frequency response and reserve services. This would need to be compatible with managing the network constraint. | • **Commercial framework** – in this Case Study we look at the demand management of household thermal loads to reduce generator curtailment. A mechanism is required to share the value to the generator and system value of increased renewable generation with participating households. The could involve a customer rebate, which has the benefit of simplicity, or a variety of local tariff arrangements. |
| **Multi Vector EfW** | • **Ramping of process technologies** – this Case Study involves switching biogas produced by an EfW plant between combustion in a CHP engine and upgrade to grid quality for injection into the gas grid. This could involve ramping up and down of process technologies, such as biogas to biomethane upgrade, in response to fluctuating price signals. The ability of these processes to be operated flexibly in this way is believed to be untested (in a commercial operating environment).<br>• **Gas network injection** – Similarly with the power-to-gas case, there are potentially restrictions on the gas network's capacity to accept gas injection, e.g. at low demand periods. The costs associated with gas grid entry have also been identified as an issue for distributed gas producers and are being investigated in the CLoCC project. | • **Real-time price optimisation** - Similarly to the multi vector district heating case, to maximise the economic case of switching between CHP and gas grid injection requires exposure to real-time wholesale electricity and gas pricing.<br>• **Planning for EfW** - Planning restrictions on EfW near housing and other developments may limit the opportunities for use of the CHP thermal output. |

## 4.2 Operational benefits of multi vector systems

Conditions of energy generation, supply and distribution are stipulated in the License Obligations, which encode network design and operation principles. OFGEM assess the extent to which energy system participants operate according to these principles using the RIIO (**R**evenue set to deliver strong **I**ncentives, **I**nnovation and **O**utputs) price control framework; on which basis they are rewarded or penalised (RIIO also aims to encourage further network innovation and investment, and ensure provision of services to consumers at a fair price). In the table below, we give an overview of the regulation categories; network capacity, customer costs and low-carbon investment are not considered as primary outputs in the RIIO framework, but are included here as network companies' business plans are obliged to meet certain criteria that are relevant to multi vector energy supply.

*Table 57 – Overview of the regulation categories as used in the RIIO model and Ofgem business case assessment*

| Regulation categories | | Description | Example RIIO Output Measures |
|---|---|---|---|
| Network | Safety | Maintaining a safe network in compliance with Health and Safety Executive (HSE) safety | 1. Minimum legal requirements as specified by the Health and Safety Executive<br>2. Additional safety initiatives considered to be in public interest |
| | Capacity | Ensuring capacity is available where and when it is needed | 1. (Long-term) strategy in business plan to ensure sufficient capacity |
| | Network availability and reliability | Complying with the minimum levels of performance as set out by Ofgem | 1. Customer interruptions<br>2. Customer minutes lost or energy not supplied |
| Customers | Social obligation | Providing service to vulnerable customers | 1. Targets for vulnerable customers, e.g. Public Sector Obligations |
| | Customer service | Engaging with customers and thinking about their needs | 1. Broad measures of customers' satisfactions reflecting experience of consumers and network users<br>2. Qualitative survey evidence |
| | Connections | Connecting customers to the network | 1. Time to connect a generation node<br>2. Time to connect a demand node |
| | Costs | Offering fair, cost-reflective costs to consumers needed to ensure delivery of primary outputs and secondary deliverables | 1. Consumer costs<br>2. Future increase in consumer costs as a result of network investments proposed in business plan |
| Environment | Environmental performance | Improving the network's impact on the environment | 1. Carbon footprint of network including losses<br>2. Other emissions<br>3. Visual impact<br>4. Role in consumer energy efficiency |
| | Low-carbon investment | Investing in assets, processes and initiatives that enable low carbon technology to be connected to the network | 1. Proportion of new low carbon generation<br>2. (Long-term) strategy that enables higher penetration levels of low carbon technology |

Below, we review aspects of these requirements relevant to the energy networks as the multi vector energy supply configurations we have assessed are implemented at increasing scale, and discuss how these solutions may make it simpler or cheaper to operate in line with the principles encoded in the LO's[70].

[70] Our focus is on a whole network perspective, i.e. we do not consider the impact on individual network companies, and primarily on the power and LO's for gas and power; (heat networks are subject to relatively little regulation, hydrogen networks are not yet operational, and liquid fuel supply has been shown to offer little multi vector benefit.

*Table 58 – High-level overview of the impact of multi vector compared to single vector operation on regulation design and enforcement (green shading implies major and direct regulatory benefits, light green indicates benefits that are expected to be less significant, and the yellow shading is related to a minor negative impact*

| | | | Network | | | Customers | | | | Environment | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Safety | Capacity | Network availability and reliability | Social obligation | Customer service | Connections | Costs | Environmental performance | Low-carbon investment |
| **Case Study** | **Multi Vector** | **Single Vector counterfactual** | **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** | **I** |
| **1** | Domestic heat pumps and peak gas boilers | Pure electric heat pumps with DSM | | 1.1 | 1.5 | | 2.2 | | 2.4 | 3.1 | |
| **2** | Combined Gas CHP and Heat Pumps | Gas CHP or heat pump based network | | | 1.6 | | | | | 3.2 | |
| **3** | Hybrid electric vehicles using petrol or diesel | Demand managed electric charging | | | | | | | | | |
| **4** | RES to $H_2$ / $CH_4$ | Grid reinforcement | | 1.2 | | | | | | 3.3 | |
| **5** | $H_2$ for a hydrogen network from grid electricity | SMR-produced $H_2$ for hydrogen network | | | | | | | | | |
| **6a** | Wind to DH | Independent DH and wind park | | 1.3 | | | | | | 3.4 | |
| **6b** | RES to Smart Electric Thermal Storage | Network reinforcement and curtailment | | 1.4 | 1.7 | 2.1 | 2.3 | | 2.5 | 3.5 | |
| **7** | Flexing between CHP and gas grid injection | Biogas grid power / injection | | | 1.8 | | | | | | |

The areas where multi vector systems could contribute toward achieving network outputs are discussed in more detail in the tables below.

*Table 59 – Opportunities for multi vector systems to contribute to the network's RIIO outputs (Ref numbers relate to the matrix of outputs in Table 58)*

**NETWORK**

| RIIO output | Ref | MV system | Summary | Implementation |
|---|---|---|---|---|
| **Network Capacity** | 1.1 | **Hybrid Heating** | Multi vector heat supply reduces considerably the DNO capacity upgrade requirement associated with the electrification of heat, by substituting to gas supply at times of peak demand (quantified in the WP3 report). In a highly electrified future therefore, DNOs might incentivise network users to select hybrid heat pumps, and undersize, or allow control of, these – rather than investing in increased network capacity. | DNOs determine their future capacity requirements on an eight-year cycle through the price control mechanism; with the next update to cover 2023 to 2031. Support for heat pumps is expected to drive significant uptake during RIIO-ED2, with projections for 4m units installed by 2030[71] and, in some studies, more than 7m[72]. Domestic hybrid heat pumps are supported by the RHI (when installed with metering), but there may be a case for additional incentivisation of hybrids, given the potential for reduced social costs of substantial heat electrification.<br>The load management of hybrid heat pumps could be implemented in a number of ways. The units could internally optimise fuel selection to reduce running cost or carbon emissions, based on real-time price and grid carbon data. Alternatively, a direct load control mechanism could be used to ensure that the systems are switched to gas-fired operation and times of electricity network peak load, potentially via aggregators. This latter mechanism is likely to unlock the greatest benefit in terms of avoided electricity network reinforcement, as it would enable switching on a spatially resolved basis to manage those LV networks that are most stressed. However, as discussed in the Case Study analysis, simply limiting the capacity of the heat pump device within the hybrid system could deliver a significant proportion of the benefit in terms of avoided network reinforcement. |
| | 1.2 | **Power to Gas** | Power-to-gas allows renewable oversupply to be converted to $H_2/CH_4$ and injected into the gas network, sold or stored, and could be used to assist DNO renewable connection obligations as a means of absorbing network oversupply, particularly in areas where there is a market for hydrogen, e.g. where: | Power-to-gas could help to mitigate a number of network issues, both at transmission and distribution level, related to large-scale connection of inflexible renewable generators. Under the Connection and Use of System Code (CUSC), DNOs must make a connection offer to proposed embedded generation within 3 months, and (in parallel) request a Statement of works (SoW) from |

[71] *Pathways to high penetration of heat pumps*, Frontier Economics and Element Energy for the CCC (2013)

[72] *2050 Pathways for domestic heat, Delta EE, 2012*

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|---|---|---|---|---|
| | | | 1. Power networks are weak and/or constrained but there is HP gas network capacity.<br>2. There is high value demand for hydrogen; e.g. wind-to-$H_2$ is operational on Orkney, where hydrogen displaces diesel as a ferry fuel. | National Grid Electricity Transmission (NGET) on potential upstream effects; where there are transmission level implications significantly delays, and increases the costs of, connection[73].<br>Electrolysers can provide large, flexible demands to allow DNOs (or DSOs) to manage network capacity issues and reduce or avoid export of power from their system to the transmission network, thereby reducing TN implications of connecting embedded generation. This could allow quicker and cheaper connection of renewables, while increasing the capacity of the network for renewables and reducing curtailment.<br>While electrolysers can resolve capacity issues on the electricity network, there are network capacity issues on the gas network to be considered in power-to-gas systems with gas grid injection. Fundamental to any injection of hydrogen in significant quantities will be revision of GS(M)R to allow higher concentrations of hydrogen in the gas networks, as is being explored in the HyDeploy project. Even at blends of 10-20%, there may be locational restrictions on the points of injection of large-scale electrolysers, as areas of high gas throughput will be required to maintain $H_2$ concentration within the blending limits. Furthermore, RES oversupply issues on the electricity networks are likely to occur during periods of low demand, which will often coincide with low gas demand periods, which could restrict the capacity of the gas network to accept $H_2$ injection. This could further limit the points on the gas network that can reliably offer a reservoir to divert oversupply of renewable electricity generation. |
| | 1.3 | **Power to Heat** | We have investigated the value of dedicated connection of wind farms and large, electrically powered heat networks. There is a broader opportunity in power to heat; as embedded generation (especially renewables), and large controllable loads (e.g. heat pumps) connect to the 11kV – 132kV networks it increases the gap between the maximum and minimum (potentially reverse) power flow across transformers. Use of storage to coordinate | Similarly to above, heat networks with large-scale heat pumps or electric boilers could provide a flexible demand to balance power flow on networks with significant embedded generation. There appear to be fewer implementation challenges associated with the use of electricity that would otherwise be curtailed for heat production, although the materiality of this solution will depend on the extent to which heat networks, which are most likely to serve urban areas, are co-located with constrained renewable generation and the correlation between negative residual load on the electricity system and periods of heat demand. On the latter point, studies in Germany have found that there is significant power-to-heat potential based on renewables oversupply[74]. |

[73] NGET have indicated that in some areas they will have to reinforce parts of the NETS prior to the connection of any further generation capacity. Where this arises DNOs must make a formal Modification Application to identify the detail, scope and costs of these works. “Customers who initiate these works will be required to fund the cost and may need to wait for NGET to complete the reinforcement. The costs will be significant and the associated construction timescales lengthy”.

[74] Potential of Power-To-Heat Technology in District Heating Grids in Germany, Böttger et al, Energy Procedia, vol. 46, 2014

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| | | | thermal demand and renewable generation allow greater capacity of both to be included on the network without further investment. | |
| | 1.4 | **SETS** | Aggregated domestic heaters and storage may provide a means of avoiding curtailment for embedded renewables. Thermal electrification is expected to increase significantly, due to heat pump uptake and panel heaters installed in modern buildings. Many modern storage heaters and home energy controllers are "aggregator ready", so that there may be over 15GW of controllable domestic load by 2030. | As above, control of sufficient load could allow greater utilisation of network assets, including greater connection or utilisation of renewables. The materiality of SETS as a flexible demand for network demand management is likely to depend on the relative costs of accessing this flexibility, for example compared to flexible I&C demand, and the extent to which domestic heating systems with thermal storage (storage heaters, immersion heaters or heat pumps with storage) can provide flexibility, given occupant comfort requirements and limitations on storage capacity.<br><br>Implementation challenges for SETS are common with other domestic demand management opportunities that involve aggregation of large numbers of individual systems, including achieving secure and reliable communications to the devices, ensuring control algorithms maintain consumer utility (in this case thermal comfort), achieving consumer acceptance and so on. Commercial offers to provide consumers to participate are also required.<br><br>The value of SETS is currently being explored in areas such as Mull, where there is a high potential for renewable generation, but a weak electricity grid. The island is off the gas grid, so there is also a high penetration of electric heating. In other cases, the potential to use low cost power in addition to, rather than instead of, oil or gas heating is being explored. Business models which install or retrofit immersion elements in boilers, and sell load matching services to DNs using the aggregated flexible load are currently being tested in Ireland. |
| **Availability and Reliability** | 1.5 & 1.7 | **Hybrid Heat Pumps & SETS** | The ability to move thermal demand off the power grid at short notice means that in the event of generator or circuit failure, demand can be ramped down rapidly. Heat could also be supplied to homes where gas or power supply has been interrupted.<br><br>Substantial hybrid heat pump rollout might allow interruption of one vector supply, for e.g. street-by-street switching to hydrogen or | The UK government reliability standard calls for no more than 3 hours' loss of load expectation per year[75]; as gap between maximum generation and peak demand closes, the SO is increasingly using DSM as a capacity management tool, for example creating Demand Side Balancing Reserves (DSBR) comprising 2.6GW of I&C demand. The DECC/Ofgem Smart Grid Forum estimated there may be up to 40GW of heat pumps connected to the grid by 2050, which could be managed to provide a range of reserve and frequency response services to National Grid. Indeed hybrid heat pumps may provide additional flexibility, for example facilitating demand turn-down during periods of high thermal demand when pure electric heat pumps are less likely to be available for reserve services. |

[75] Ofgem - Electricity Security of Supply

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| | | | replacement of iron mains, with minimal disruption. | Currently, power system margins are reviewed annually by National Grid; where there is a risk of insufficient generation capacity NG create incentives to encourage further peak generation or load reduction through demand management (their work is reviewed in the Ofgem Capacity Assessments). Consideration of demand management in determining energy system capacity requirements is in its early stages, and so far involving primarily HV industrial and commercial loads; work may be need to demonstrate the safety and efficacy of domestic load management. |
| | 1.6 | **Multi Vector DH** | Heat network energy centres that can operate independently of grid supply or that can export power to the grid without interrupting heat supply offer a great deal of flexibility to provide grid support services. | Non-firm connection offers could be developed that allow potentially self-sufficient energy centres to connect more cheaply, and with less demand on network resources at periods of stress.<br>Multi vector heat supply – using heat pumps and CHP in tandem – enables greater future development (and viable use at high fuel and carbon prices) of gas CHP, which may contribute to the increased resilience of electricity distribution networks.<br>The multi vector energy centre offers significant flexibility to provide ancillary services (reserve and frequency response), as well as support to local distribution networks. |
| | 1.8 | **Multi Vector EfW** | Parallel operation of CHP and gas injection allows power to be supplied to a local network during periods of high demand (or potentially in an islanded configuration during a circuit failure), or when the EfW facility cannot inject biogas due to capacity constraints on the gas network. | As for multi vector heat networks, flexible dispatch options may allow connection of large CHP facilities to grids which are intermittently constrained or interrupted, as well as potential reserve service provision. |

## CUSTOMERS

| RIIO output | Key | MV system | Summary | Implementation |
|---|---|---|---|---|
| **Social Obligations** | 2.1 | **SETS** | Storage and immersion heaters may allow electrically heated homes – which are overrepresented in the fuel poor sector – to reduce their bills by managing their demand in response to a dynamic tariff or selling load matching and FR services. | Our analysis suggests the value of load management is between £25 and £125 per household per year. At the upper end, this is expected to be significantly greater than the per home cost of providing the necessary control technology to enable management of the SETS demand. As |

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| | | | More ambitiously, community ownership of renewables may be developable where flexible demand allows sufficient generation to be absorbed on weak grids. | discussed in Section 3.7.4, there are a number of potential mechanisms for this value to be shared with householders. |
| **Customer Service and Experience** | 2.2 & 2.3 | **DSM of Hybrid Heat Pumps** and **SETS** | Improvements to customer service and customer experience may be marginal – the primary goal here will be to ensure that customer do notice that their heating systems are being used to provide demand management services by ensuring that their comfort is not compromised. However, depending on the system architecture, the home energy management system may offer opportunities for customers to benefit from further connected home services. Consumers may also become more engaged with their energy consumption as a result of participation, resulting in further energy savings. | Some education of customers on demand management may be required. For example there is evidence that time-of-use tariffs – particular dynamic ones – are not generally popular or well understood[76][77]. Engagement with consumers will be required to ensure they don't use override switches to isolate their HHPs or SETS systems from the demand management system. HHP users may be more engaged with their energy supply as a demographic than average, and fuel substitution should ensure no change in user experience. Although users of storage and immersion heaters are likely to be on static ToU (e.g. Economy 7 and 10) tariffs, users may also require further education and/or incentives on dynamic tariffs or direct load control. |
| **Costs** | 2.4 | **DSM of Hybrid Heat Pumps** | Operating cost for the customer may decrease if network upgrade costs are avoided through reduced peak load growth. This obligation could be used to encourage DNOs to promote hybrid heat pumps given substantial electrification of heat. | Hybrid heat pump systems can reduce energy costs for householders compared to the single vector counterfactual of pure electric heat pumps. This may be increased if consumers can also share the benefit of demand management of their HHP systems, through the commercial arrangements with their supplier (e.g. pass-through of reduced DUoS charges, special tariff for HHP homes or alternative means of incentivising adoption of HHPs). Note that there is a potential negative impact on householders that continue to use gas as their primary heating fuel, as the reduced volumes of gas use lead to increase costs. This could be mitigated by the changes to the way network costs are charged to consumers (e.g. by increasing the capacity component of the charge and reducing the unit charge). |

[76] An ongoing UCL Energy Institute study found that "approximately 50% of energy bill payers failed to identify the cheapest tariff, despite being given all the necessary information".
[77] The Smart Energy GB study Consumers and Time of Use Tariffs found that only 30% of surveyed households were in favour of switching to a static ToU tariff, with less than a quarter in favour of a dynamic ToU tariff, which was viewed as difficult to use and intrusive.

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| | 2.5 | **SETS** | Customers can be given the opportunity to gain some income from a smart electric thermal storage scheme. | As discussed above and in Section 3.7.4, there are a number of potential options to ensure that SETS households are compensated for participating in a demand management programme. |

## ENVIRONMENT

| RIIO output | Key | MV system | Summary | Implications |
|---|---|---|---|---|
| **Environmental Performance** and **Low Carbon Investment** | 3.1 | **Hybrid Heat Pumps** | Flexible load may allow greater connection of renewables, particularly if heat can be stored, allowing absorption of power at times of low demand. In addition to assisting DNOs to manage future demands without large scale upgrade of their networks.<br><br>We note that as the carbon content of grid power falls, using gas instead of electricity will have a negative effect on the carbon emissions, though this represents a minor scheme cost even at high carbon prices. | The use of a hybrid system compared to the pure electric heat pump counterfactual results in a small increase in the per household carbon emissions. However, the overall system benefits of proliferation of hybrid systems can result in a significant improvement in the cost effectiveness of electrification as a heat decarbonisation pathway. The ability to manage the heat pump component of the hybrid system as a flexible load can also provide a range of services to the DNO/DSO and SO, which could help to mitigate issues associated with increased connection of inflexible renewable generators. |
| | 3.2 | **Multi Vector DH** | Multi vector plant may provide lower cost heat for heat networks. Once built, heat networks then provide increased options for decarbonisation of heat supply. For example, the gas CHP could be replaced with a biofuel equivalent, or another heat pump, as carbon prices increase. | Multi vector DH provides a range of supply configurations which can be employed to allow heat network operators to create maximum value across a range of future fuel price and environmental incentive scenarios. This means in particular that as carbon prices rise and/or the grid decarbonises, annual operation of the network can respond to a greater extent than single vector networks. |
| | 3.2 | **Power to Gas** | Electrolysers injecting $H_2$ from renewables into the gas grid could assist the gas and power networks in meeting their environmental targets – increasing the use of renewable generation and lowering the per kWh carbon intensity of gas supply. | A 10% blend limit by volume for hydrogen in the gas mains is considered a plausible target; this equates 9TWh at current levels of domestic gas use; or around 20% of 2016 UK wind generation.<br><br>. |

| | | | | |
|---|---|---|---|---|
| | 3.4 | **SETS** | Using smart thermal storage to reduce curtailment will increase the utilization of renewables and reduce transport losses, resulting in greener power. On LV DNO circuits, SETS may provide the lowest cost flexible load options, and hence allow more RES capacity to be installed. | So far, SETS has mostly relied on community engagement groups (such as CES); suppliers and DNs could incentivise use of flexible load to match renewable supply through a fixed rebate or reduced use of system charges for DLC, or a dynamic time of use tariff. We estimate the annual per household costs of SETS to be not more than £20. |

# 5 Transition to Multi vector operation

Multi vector energy supply appears to reduce system costs in some cases; there are however technical, commercial and regulatory barriers to the transition to operating the energy system in this way.

We have reviewed the barriers specific to each of our Case Studies with relevant stakeholders, these are collated in the report *D5.1 Barriers to Multi Vector Energy Supply.* By weighting these by their potential risk and impact of confounding multi vector operation, and identifying common themes, we have derived a set of common barriers to multi vector supply, and the innovations that might resolve, or simplify, these concerns.

*Table 60 – Summary of Key Barriers*

| Barrier | Multi Vector Case Studies Affected |
|---|---|
| Distribution Network Telemetry | 1. Hybrid heat pumps[78]<br>6b. Domestic turn up and thermal store (SETS) |
| Domestic Demand Response Platform | 1. Hybrid heat pumps[78]<br>2. CHP and HP in heat networks<br>6b. Domestic turn up and thermal store (SETS) |
| Need for Clarity in Low Carbon Heat Policy | 1. Hybrid heat pumps[78]<br>2. CHP and HP in heat networks<br>7. Flexible CHP/Grid injecting EfW plants |
| Gas Network Charging | 1. Hybrid heat pumps |
| Future of Hydrogen | 4. P2G- injection into NTS<br>5. P2G into dedicated hydrogen network |
| Increased Coordination | All Cases Studies |

The barriers and innovation opportunities in each of these areas are discussed below and further detail is included in the report *D5.1 Barriers to Multi Vector Operation.*

## 5.1 Barriers and Innovation

### 1. Distribution Network Telemetry

Where multi vector operation involves active management of existing power grids to accommodate growing peak demand or renewable generation, implementation requires an accurate picture of the grid loads at each component. This however requires highly granular, real time data on network loads; while the HV network is monitored, most of the LV network is unmonitored and has historically been designed on a “fit and forget” basis. Also, LV network upgrade costs are significantly more expensive per kW than their HV counterparts. Realising the full value of single and multi vector supply configurations through demand response will therefore require significantly increased network telemetry (we have considered multi vector heating in detail in this study, however the telemetry and network management systems

[78] Multi vector heat supply might also mitigate network loads by under sizing heat pumps and supplying peak demand using gas; this would not require sophisticated network telemetry or a DR platform, but does depend on policy to maintain gas connections and boilers at heat pump equipped homes.

required for multi vector heating may enable further grid services, such as mitigating the risk of high summer reverse power flows as more PV is installed, and enabling vehicle to grid services).

Load monitoring and active network management are the focus of several recently concluded and ongoing innovation projects, which explore means to increase DNO capacity for embedded generation and low carbon technologies (LCTs). In particular, the spatial and temporal telemetry resolution required to safely maximise utilisation of existing LV network assets is the subject of several innovation projects, e.g. WPD's Open LV project, which aims to make detailed real-time data from 80 substations available, allowing third party software developers to create applications that provide demand management services to customers and/or DNOs. The project funding requirements suggest an upgrade cost of not more than £50k per LV substation, including the outgoing feeders. On this basis, the costs of LV network telemetry for Newcastle (on which the Case Study 1 analysis is based) would be £375m – around 10% of the costs of network upgrade necessitated by substantial electrification of heat (we consider 65% heat pump uptake by 2050).

Smart meter roll-out might provide an alternative means of improving DNO LV monitoring:

- Real-time smart meter data may provide sufficient information to determine the instantaneous load at network components; in this solution, DNOs will need to create a coherent network flow model which takes real time or half hourly MPAN readings as inputs; there may be data quality, resolution and data protection concerns around this.
- Even without a deterministic load model, smart meter consumption data may allow a stochastic model, calibrated against historical usage patterns, to predict network loads based on time, date, weather forecasts, occupancy data and other relevant parameters. Such a model could inform demand management strategies (load control or pricing) to avoid peak load issues on the LV network. Use of a ANM models which infer, rather than measuring or calculating, component loads will need to carefully consider the risk of prediction failure, though comparatively simple current models can predict network demand based on time of day, day of the week and weather forecast relatively accurately. Smart meter data may allow extensive fine tuning, development and testing of these predictions.

Smart meters can also report gas demand on a half hourly basis; no multi vector supply issues identified in our Case Studies are resolved through a more granular understanding of gas flow across the DNs, though this data may be of value in e.g. identifying network leakage.

Increased gas network telemetry may be required under some multi vector supply configurations, such as those involving injection of distributed gas sources, or hydrogen blending. As biogas and hydrogen are injected into gas networks, distributed monitoring is one means by which the Wobbe Number and/or CV might be recorded, for safety and local billing reasons. These data could also determine maximum injection levels for hydrogen and biomethane or bioSNG, ensuring gas characteristics remain within acceptable limits. The tools to determine the hydrogen content of natural gas, and to measure gas CV are currently expensive; trials are ongoing to develop prototype chromatographs, and commercialise these to allow their deployment across the network.

## Innovation actions

### Use of smart meter data

Smart meter data may provide a path to enhanced LV network visibility without installation of extensive network monitoring.

Data analytics techniques such as machine learning applied to historic smart meter data, weather data, demographic data etc. may enable development of stochastic predictive models of loads on LV network components

## 2. Domestic Demand Response Platform

Demand-side response in the domestic sector is a key area of innovation work for network operators as well as energy supply companies, as they seek cost-effective means to:

- minimise grid upgrade requirement
- ensure security of supply
- maximise use of renewable generation

Particularly as electricity demands are expected to increase substantially due to increasing electrification of heat and transport. The Case Study 1 analysis has demonstrated that smart demand management of multi vector heating systems (hybrid heat pumps) can unlock significant value in terms of reduced requirement for network reinforcement. Recent work within Low Carbon Network Fund and Innovation Stimulus projects has trialled a number of mechanisms for domestic demand management. The main candidate options and how they might apply to the case of management of hybrid heat pump systems are briefly summarised in the table below.

*Table 61 – Domestic Multi Vector Heat DSM Mechanisms for LV Network Management*

| Mechanism | Implementation / Coordination | Required Grid Reinforcement | Consumer Attitudes | Platform Cost |
|---|---|---|---|---|
| **Direct Load Control (DLC)** | DNO would need control over heat pump interface or connected circuit. Smart meter ALCS is one option, control of gas boilers may also be needed. | Our modelling suggests DSM might obviate all grid upgrade, provided feeder loads are monitored, and there is at least 25% network headroom. | Potentially the most contentious solution; but would require minimal user involvement once operational. The WPD Smart Plug ECHO trial found an appliance control cost of £6.6/kWh, prohibitive for ANM, though these findings may not apply to multi vector heating, where gas substitution should allow uninterrupted heating. | These solutions are likely to have similar platform costs, (the firm control costs per kW may be lower for DLC). |
| **Time of Use Pricing (ToU)** | Customer ToU pricing be controlled by suppliers; DNOs would have to set price signals for all suppliers across their network., consumers must “opt-in” to smart meter half hourly settlement; this may represent a barrier to ToU pricing ANM. | | Consumer price elasticity is not well understood; the Low Carbon London trials found average reductions of 0.05kW/household (up to 0.15kW/household) during peak price periods. As above, it is not clear that these findings are directly applicable to multi vector heating. | |
| **Appliance Sizing** | Limits system hybrid heat pump load by under-sizing the electrical unit. Unit electrical power might be limited through regulation e.g. installers might provide HHPs or support structure, with low carbon subsidy qualification made subject to selection of a heat pump of prescribed size (and perhaps minimum building fabric standards). | We find load limiting avoids substantial upgrade without need for a DSM system; it may therefore be a preferred solution where HHP uptake is modest and LV grid headroom is significant. | Lower up-front costs may incentivise consumer take up of smaller HPs, though mandation of undersized units may be unpopular. | None, though there may be some administration costs |

### Time Resolution of Demand Response

Active power network management, though direct load control or time of use pricing, may result in large instantaneous drops or spikes in power demand where e.g. all EVs connected to the network cease charging as power prices rises some threshold. Where power and gas network operation are linked through multi vector supply, there may also be surges on the gas grid, which is designed to peak demand averaged over periods of 6 minutes, rather than seconds.

These issues might be resolved by introducing a random delay between the device responding to a control signal and the actuation of device switch-over; thereby synthesizing some of the diversity which currently arises naturally.

## Innovation actions

- **Flexible low carbon heating trials**

If the path to decarbonisation of the heat sector is through electrification, significant investment will be required in the electricity network.

Multi vector heating technologies, such as hybrid heat pumps or heat pumps and micro-CHP can mitigate these impacts. These technologies compete against flexible single vector heating technologies such as heat pumps with high density thermal storage and smart storage heaters.

Increased field trial activity is required to assess the technical suitability of these heating appliances in a range of house types and the flexibility they can provide to the network operator (and potentially other electricity system participants). Such field trials could also be used to establish the impact of multi vector heating technologies on the gas network and whether impacts can be managed through the control strategy, rather than network reinforcement.

- **Control systems and DSR mechanisms**

Such field trials could also investigate the effectiveness of different control technologies and strategies (direct load control, time of use tariffs etc.) at securing firm demand response.

## 3. Need for Clarity in Low Carbon Heat Policy

Our analysis considers the following heat supply technologies:

1. Electrification, through (possibly hybrid) heat pumps and smart storage heaters.
2. Hybrid heat networks (CHP powered heat pumps and multi vector EfW).
3. Hydrogen injection into the gas network
4. Hydrogen networks as a heat supply vector.

The future role of these technologies in the decarbonisation of heat will be driven substantially by policy;

1. Future domestic multi vector heat supply depends on today's infrastructure decisions; customers and housing developers are not currently incentivised to install or maintain flexible heat supply plant and infrastructure – e.g. gas network connected hybrid heat pumps rather than pure electric units, or smart, aggregator-ready storage heaters. Where up-front capital costs are higher for multi vector infrastructure than for single vector alternatives, policy could leverage future benefit to support uptake of multi vector ready solutions.
2. Heat networks de-risk the decarbonisation of heat, particularly for new build and large facilities, as supply plant can be chosen and replaced based on carbon prices and environmental policy. However, only around 2% of UK demand for space heating and

hot water is supplied through heat networks[79]. The development of heat networks, and the use of energy from waste, waste heat and other secondary heat sources, should be the subject of a more comprehensive, long term policy.

3. Significant R&D is required before hydrogen can be blended into the gas network at scale. The HyDeploy project will explore the feasibility of blends of up to 20% hydrogen for UK gas grids, based on trials using Keele University's onsite gas network. On the NTS, any change to permissible hydrogen content of the gas blend must be agreed by all connected users. This includes gas turbine power plants, which may have stated tolerances to hydrogen blends of only 2%. These turbines are expected to remain in use for several decades, which may limit the potential for hydrogen blending into the NTS.
4. There are huge technical, commercial, logistical and consumer acceptance challenges around conversion of the gas network to supply pure hydrogen. Work on exploring these challenges is underway and it is expected that a comprehensive programme of technology development and trials will be required over the next decade to prove the feasibility of the conversion and reach the point at which conversion to hydrogen could be rolled-out across real networks. Any decision to transition to hydrogen networks is likely to be driven by government policy, i.e. mandated as a strategic infrastructure decision, rather than market forces.

Significant work must be done to provide the evidence base needed to inform strategic decisions regarding the decarbonisation pathway for the heat sector. It may well be that several solutions will co-exist, as different parts of the country are more suited to particular solutions. Also, decisions made in the heat sector have inter-dependencies with strategy in other areas; the decision to progress with widespread conversion to hydrogen, in particular, is likely to have strong inter-dependencies with policy around deployment of CCS and decarbonisation of transport.

The challenges associated with defining a UK heat strategy are clear, and government will wish to pursue policies that keep options open for as long as possible. However due to the significant differences between the various options, in:

- infrastructure requirements
- energy market design
- regulatory framework

and other areas, there is a risk of wasted effort, innovation spending, and stranded assets if government does not provide a strategic lead.

[79] The Future of Heating §2.6

## Innovation actions

- **Low carbon heating technology trials**

Government is currently undertaking modelling of a range of potential heat decarbonisation pathways to inform future policy decisions. In addition, a number of innovation projects are underway or in development to provide further evidence on the feasibility of different pathways, particularly use of hydrogen in the gas grid.

As highlighted in the preceding section, field trials of multi vector heating technologies, such as hybrid heat pumps and micro-CHP, would provide crucial evidence to inform government's future strategic decisions on heat decarbonisation.

- **Funding research into multi vector energy systems**

To improve understanding of the potential role of multi vector energy systems and answer key questions such as what the role of the gas network should be, will be require significant additional research and funding. Network Innovation Stimulus funding, which makes substantial funding available to gas and electricity network operators seems like an appropriate mechanism to provide this funding. However, cross network projects (i.e. involving electricity and gas network operators) have been limited, with only a few multi vector projects receiving funding to-date (notably WWU's Freedom project) and several cross-vector proposals being rejected. This may partly be because projects are required to demonstrate the benefit to network users, while for multi vector projects the benefit may accrue outside the network (particularly for gas networks). Revision of the assessment criteria to ensure multi vector projects are assessed on their wider benefits should be considered.

## 4. Gas Network Charging

Uncertainty surrounds the future of the gas network; depending on the future of heat, it may be:

- Incrementally decarbonised, using low carbon gases such as biomethane and green hydrogen
- Re-purposed to carry pure hydrogen
- Decommissioned due to falling utilisation, at least at lower pressure tiers, e.g. under large-scale switchover to electric heating
- A mixture of these outcomes

Gas network decarbonisation could be achieved via a number of routes. For example:

- a carbon reduction of up to 9% could be achieved at high hydrogen blends,
- by injection of up to 100TWh of biogas by 2050, produced by gasification of waste on a large-scale.

Alternatively, if gas networks become a peak only supply vector as heat is substantially electrified, e.g. multi vector heating as studied in Case Study 1, then a new model for gas network companies to recover the costs of operating the gas networks is likely to be required. The impact of multi vector heating on the economics of gas networks is discussed in appendix 7.1.3 and potential options for a revised network charging model are discussed below.

*Table 62 – Potential Means of Charging Gas Network Connection*

| Basis of Charging | Description | Impact |
|---|---|---|
| **Current System** | Suppliers are charged by GDNs; >95% of this charge comprises a capacity charge. Suppliers recoup these charges from domestic customers through tariffs comprising a standing charge and a (flat) unit price. | Domestic gas network use is charged on a commoditised basis. As total gas use falls, recovering largely fixed GDN costs from single and multi vector users on a marginal use basis may lead to higher fuel costs; significant gas users (e.g. homes on gas only heating) will therefore subsidise the connection costs of peak-only users. |
| **Local Connection Zones** | Increased granularity of gas network connection charges could reflect the extent to which users drive usage or investment costs, particularly where individuals can choose the relative size of their HP and gas boiler, and have significantly different heat demands (e.g. due to property size). For hybrid heat pump users, this tariff could reflect some combination of level and frequency of gas use. | Local connection charging might discourage e.g. new build connections to congested gas networks and encourage biomethane plants to connect to them. |
| **Multi Vector Tariff** | Hybrid heat pump users could pay a gas connection cost that reflects their pass-through charges more efficiently e.g. through a capacity charge based on their maximum use. | As an increased component on multi vector bills, this may disincentivise hybrid heat pump uptake. |
| **Paid with avoided DNO investment** | Some fraction of gas system cost recovery could be subsidised by avoided electricity system investment. For example, part of the gas network regulated asset base (RAB) could be transferred to the electricity DNO to be recovered from electricity customers. | A form of socialisation of gas grid cost. It may prove unpopular with electricity consumers, particularly those without a gas connection, requiring clear communication. |
| **Socialisation** | As gas throughput falls, increases in standing charges could be capped, with any shortfall in GDN cost recovery socialised across all energy consumers (this cost could be controlled via the Levy Control Framework budget), or through general taxation. | Effectively subsidising the energy supply of multi vector homes may be inequitable and/or unpopular. |

## Innovation actions

- **Assessment of gas network cost recovery model**

In the multi vector heat decarbonisation scenario explored in Case Study 1, the gas network remains a key part of heat supply infrastructure, but at much reduced throughput.

The charging model for the gas network may need to change to reflect the need to recover opex and depreciation costs from significantly lower gas volumes transported. Any revised charging model must ensure gas network costs are split equitably across users and provide the necessary incentives for network companies to invest in the networks despite reduced projected volumes.

The CCC and BEIS have begun exploring this issue. Further work will be required on the appropriate regulatory model for closer multi vector integration – considering both gas and electricity networks (and potentially heat regulation).

- **Sharing multi vector system benefits across network companies & customers**

The CCC Future Regulation of the UK Gas Grid study put forward the proposal that part or all of the gas network RAB could be transferred to electricity networks, to be recovered from electricity customers. Other means of effectively socialising the cost of maintaining the gas network, for example through a levy on all energy consumers could also be considered.

## 5. Future of Hydrogen

Hydrogen for gas blending is currently being investigated at the HyDeploy trial; which aims to demonstrate a blend level that is “no less safe” than current levels (0.1% by volume). Once this is agreed however, it is not clear at what scale gas blending will be pursued as a means of gas grid decarbonisation; the findings of Case Study 4 has demonstrated that the electrolyser business case in power-to-gas applications is likely to depend on capital cost reductions and availability of low cost power (potentially with access to higher value markets for hydrogen than gas grid injection), while Case Study 5 has shown that electrolysis struggles to compete with SMR as a route to hydrogen production at the scale needed for hydrogen for heat (albeit that the viability of SMR is itself highly dependent on factors that are currently uncertain, principally the future and costs of CCS).

A pathway to a higher hydrogen blend level on the NTS is less clear, given the necessary assent of all NTS connected users, many of whom operate plant with hydrogen tolerances of around 2%, and significant remaining lifetime.

Conversion of gas grids to 100% hydrogen supply constitutes a huge challenge; concerted policy action is needed (as discussed above) and switching in the most efficient manner is a complex coordination task. Several key technical questions regarding the optimum system design and the role of supply technologies are unresolved. Further work is expected within successor projects to the H21 study, currently expected to be funded through Network Innovation Stimulus funds, and through work funded by BEIS.

## Innovation actions

- **Extensive programme of research into hydrogen in the gas network**

As described above, a range of innovation projects are expected to explore the possibility that the as grid could be re-purposed to supply hydrogen, stimulated by the Leeds H21 study. Conversion of the gas networks to hydrogen is generally recognised to be at least 10 to 15 years away, assuming the feasibility can be proven. From a multi vector perspective, the work beginning through the HyDeploy project on hydrogen blending limits is a priority, as this is a pre-requisite for power-to-gas without methanation (which has been found to be very challenging economically).

- **Electrolyser role in the transition and business case**

The business case for electrolysers producing $H_2$ for gas grid injection has been found to be challenging. The potential for grid-connected electrolysers to provide services to the electricity system has been considered, although not quantified in detail. Further trials could be undertaken to establish the benefits electrolysers can provide to the electricity system (e.g. when installed for power-to-gas applications) and the impact of such service provision on the business case.

## 6. Increased Coordination

Many of the component tasks of multi vector operation above can be performed centrally by energy system players, such as heat network operators, even where they involve data sharing or strategic consideration across vectors. Others comprise a set of tasks which do not fall within the remit of a single energy system player, and will require some oversight and management. These second "distributed" opportunities could be coordinated by the regulator (e.g. by requiring all network permitted investment to be compared against multi vector alternatives), or – more radically – by devolving some oversight of distribution networks and small-scale generation planning to Local Authorities. It is likely that central government would have to make funding and expertise available to support and appraise the assessment and development of multi vector energy supply.

## Innovation actions

### Joint investment planning across the networks

Closer cooperation between network operators will be vital for deployment of multi vector energy systems and to ensure cost-effective investment in the networks overall. Gas and electricity network companies could be required to demonstrate to Ofgem that multi vector alternatives and trade-offs have been explored in developing investment plans. In a more radical approach, gas and network operators could be required to produce joint plans for network investment within their business plans. Initially, a theoretical joint planning exercise could be undertaken between a gas and electricity network company for a particular area. The exercise would identify how joint planning (at different degrees of integration) could work in practice and the data that would need to be shared between the network companies. The exercise would also identify potential savings through the joint approach compared to single vector investment planning. We note the investment/price review periods for electricity and gas are currently not aligned (2013-21 for gas and 2015 to 2023 for electricity).

### Increased role for local energy planning authorities

There may be an increased role for a local energy planning function, e.g. within the local authority, to work with network companies on development of joint infrastructure plans. The local energy planning authority would undertake analysis to identify energy infrastructure requirements, integrating data on local growth plans, heat mapping studies and so on to inform the network investment planning (for example using tools such as ETI's EnergyPath Networks software).

### Network regulation

Increasing coordination of network companies in developing their business plans (potentially toward developing joint plans) is likely to require significant revision to the regulations, to ensure incentives are aligned, avoid rent-seeking and resolve commercial tensions between the network companies). Ofgem could undertake work to consider how regulation might be changed to

## 6 Glossary and Acronyms

| Term | Definition |
|---|---|
| AD | Anaerobic digestion |
| ASHP | Air Source Heat Pump |
| BAU | Business as Usual |
| BEV | Battery electric vehicle |
| BSUoS | Balancing Service Use of System charges |
| 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 |
| DSM | Demand side response |
| 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 |
| FCV | Fuel Cell Vehicle |
| FOM | Fixed O&M |
| FR | Frequency Regulation |

| | |
|---|---|
| GDUoS | Generator Distribution Use of System |
| 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 |
| PiV | Plug-in vehicle, a hybrid electric car or van. |
| 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 |
| VKT | Vehicle Kilometres Travelled |
| VOA | Valuation Office Agency |
| VOM | Variable O&M |

# 7 Case Study Appendices

## 7.1 Case Study 1: Domestic Heat Pumps and Peak Gas Boilers

### 7.1.1 Smart Storage as a Single Vector Alternative to Gas Use

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 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).

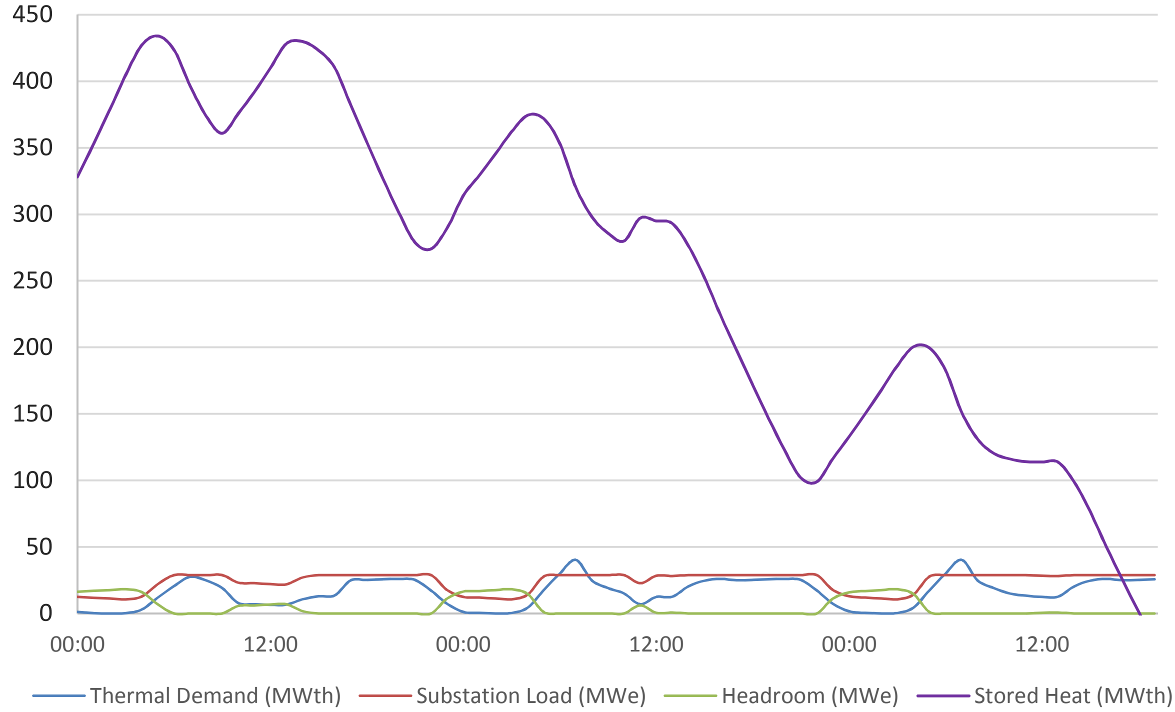


*Figure 13 - Single Vector Heat Supply and Headroom at Fossway Substation, 11th - 14th January 2040*

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. We have considered also the potential role for advanced heat storage materials, such as phase change materials (PCMs), though as these are currently used largely in bespoke, passive applications it is difficult to estimate to what extent they may improve the capacity of active domestic heat storage.

However, 2 or 3 hours' storage, as required at most substations, 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 63 – 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 Units | 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:

- The substation upgrade required to enable storage as a single vector solution,
- The carbon price, and associated increase in multi vector bills

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

### 7.1.2 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 below.

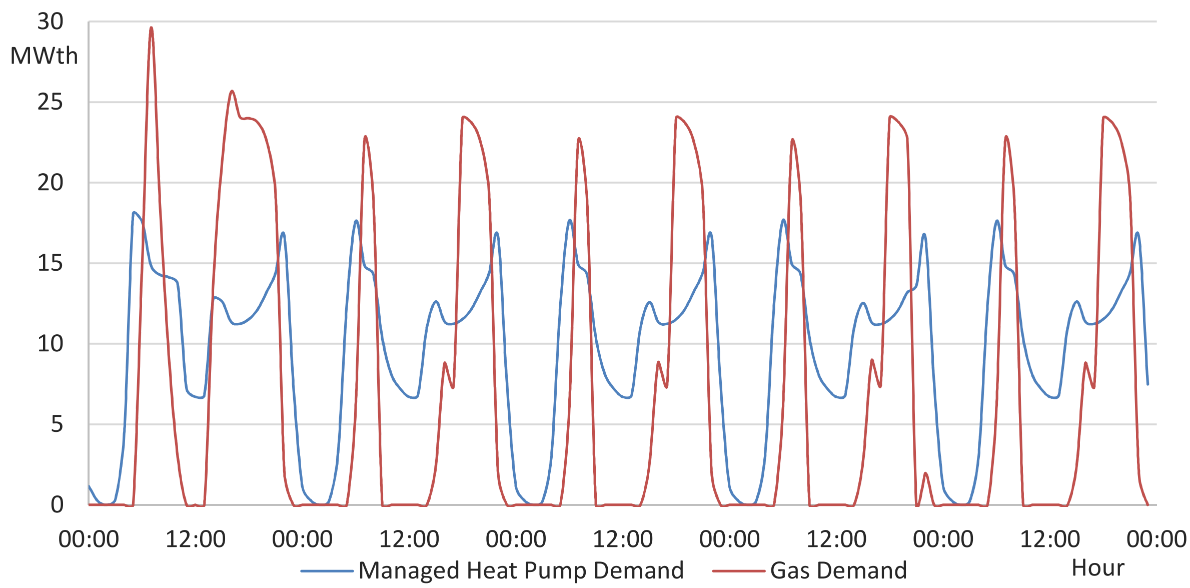


*Figure 14 – Smart MV Heat Supply at Buildings Connected to Fossway, 3rd to 8th January 2040*

*Table 64 – Multi Vector Fuel Switching at Fossway under the Smart Multi Vector Scenario in 2050*

| Month | Gas Demand (MWh) | Gas Carbon Emissions (tonnes $CO_2$)[80] | 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** |

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

### 7.1.3 Gas Network Operation

Both the single vector and multi vector cases described in this Case Study are consistent with a substantial reduction in domestic sector gas demand. Single vector electrification of heat 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 are deployed in other homes.

In the multi vector case however, the entire gas distribution infrastructure remains, but throughput is

### Gas Distribution Network Cost Recovery

Gas distribution network operators (GDNOs) aim to recover their operating costs, depreciation and return on the regulatory value of their asset base (RAV); Ofgem sets the allowed annual revenues for each operator and reviews price control periodically. Our analysis assumes that Ofgem's regulatory approach is the same in 2050 as it is today.

#### Throughput

The economics of operating the gas networks depend on overall gas consumption, comprising:

- consumption for power generation
- consumption for space and water heating
- demand at larger industrial and commercial sites
- potential use in LPG and CPG vehicles, and
- potential use in CHP

Consumption in these sectors (which is not considered in detail here) may mitigate the economic impact of the fall in consumption across the domestic sector due to uptake of heat pumps.

#### Revenue Requirements

Assuming the iron mains replacement programme (IMRP) is completed as planned (currently due to be complete by around 2030), the leakage in the low-pressure network should be significantly reduced. Together with the reduced overall demand, and more 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 distribution network operator (GDNO) revenue requirements will not reflect the reduced utilisation of the networks. Future GDN cost recovery drivers are outlined in the table below.

*Table 65 – Distribution Network Cost Drivers*

| Cost | Outlook | Effect on Costs |
|---|---|---|
| Repex | The long-running iron mains replacement programme (IMRP) comprises around two thirds of GDN capital expenditure. Tier 1 of IMRP, which constitutes 90% of the allocated cost, should be complete by 2032, (although it will take time before this is reflected a reduction in GDN charges). | There will be an increasing investment saving post IMRP. By 2050:<br>• depreciation might be around 70%,<br>• asset returns might be around 90%, and<br>• Depreciation plus return be 80%<br>of their 2021 levels. |
| Opex | Reductions will be hindered by the need to employ trained staff to respond to faults per Service Obligation requirements, specifically:<br>• Although most leaky iron mains will have been replaced, a high proportion of reported escapes are inside the house; these will continue.<br>• 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. | Many operating costs have significant fixed components, e.g. system control and head office functions such as IT and finance. Reducing running costs by as much as 50% alongside corresponding reduction in network throughput is unlikely unless there is a commensurate change in service obligations. Operating costs are therefore likely to represent a higher fraction of bills in a lower gas throughput future. |

Table 66 illustrates the potential reduction in gas DN operator revenue requirement across a range future operating cost assumptions, and the projected levels of depreciation and return outlined above.

*Table 66 – 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 substantial levels of depreciation and return remain in 2050.

A change in grid regulations might mitigate this by allowing DNs to recover the cost of investments more quickly, leading to lower future levels of depreciation and return (leading to increased short term costs).

### Charging Models

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. The impact on gas consumers of increases in the unit cost of gas distribution will depend on

- how distribution network charges are structured,
- how they are passed on to consumers by suppliers.

At present:

- distribution network charges are based on capacity (i.e. the maximum daily quantity used).
- Suppliers charge domestic consumers on a largely commoditised basis, with a typical standing charge of 10% and the rest charged based on usage

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.

### Impact on Gas Network Charges

The following table illustrates indicative percentage increases in unit cost of gas distribution (relative to the projected 2021 level) under a range of assumptions around future opex levels.

*Table 67 – 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 |

Distribution network unit costs are sensitive to total DN gas throughput; future levels of gas demand, and hence the future level of gas distribution network charges will be determined by:

- the extent of heat pump penetration,
- the amount of gas used by consumers with heat pumps and
- the scale of non-domestic gas demand

In the central case presented here, gas demand falls to at most 30% of its 2021 level; as such, gas distribution costs in this scenario are likely to be between 2.5 and 4 times their 2021 levels (assuming not change to the current regulatory framework). 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). We expect wholesale multi vector heat bills to be at least 25% less than remaining on gas (before carbon prices are considered); average multi vector fuel bills, and per kWh costs, should therefore not rise. There is however considerable uncertainty around many of these projections, particularly gas network use charges, and though average bills fall, some customers may see significant increases.

## Operational Concerns

| Parameter | Operational Impact |
|---|---|
| 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:<br>i. Non-zero for no more than 1,000 hours a year<br>ii. Significantly less than the gas demand before the installation of the heat pump.<br>As such, the current gas network should accommodate multi vector throughput levels at all points. |
| 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.<br>Modelling by project partners Liwacom, Element Energy and Imperial College, and National Grid Gas Distribution, suggests the ramp rates imposed on the gas distribution network by multi vector fuel switching will not present operational issues; even under dramatic demand spikes staggering the switch-over from electricity to gas over a period of a few minutes is likely to be sufficient (currently gas networks are designed following a peak 6-minute flow planning criterion).<br>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 management to the switch-over at this level could resolve the issue. |

## 7.2 Case Study 2 – Gas CHP and heat pumps supplying heat networks

### 7.2.1 Sensitivities

#### Power Price Volatility

As exporters and importers of electricity, the single vector CHP and heat pump schemes are most economically run at times of high and low electrical prices respectively, though peak gas boilers insulate them somewhat against price movement. Low price volatility – a more stable market - therefore increases lifetime scheme costs.

Breakdown of multi vector run mode time 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.

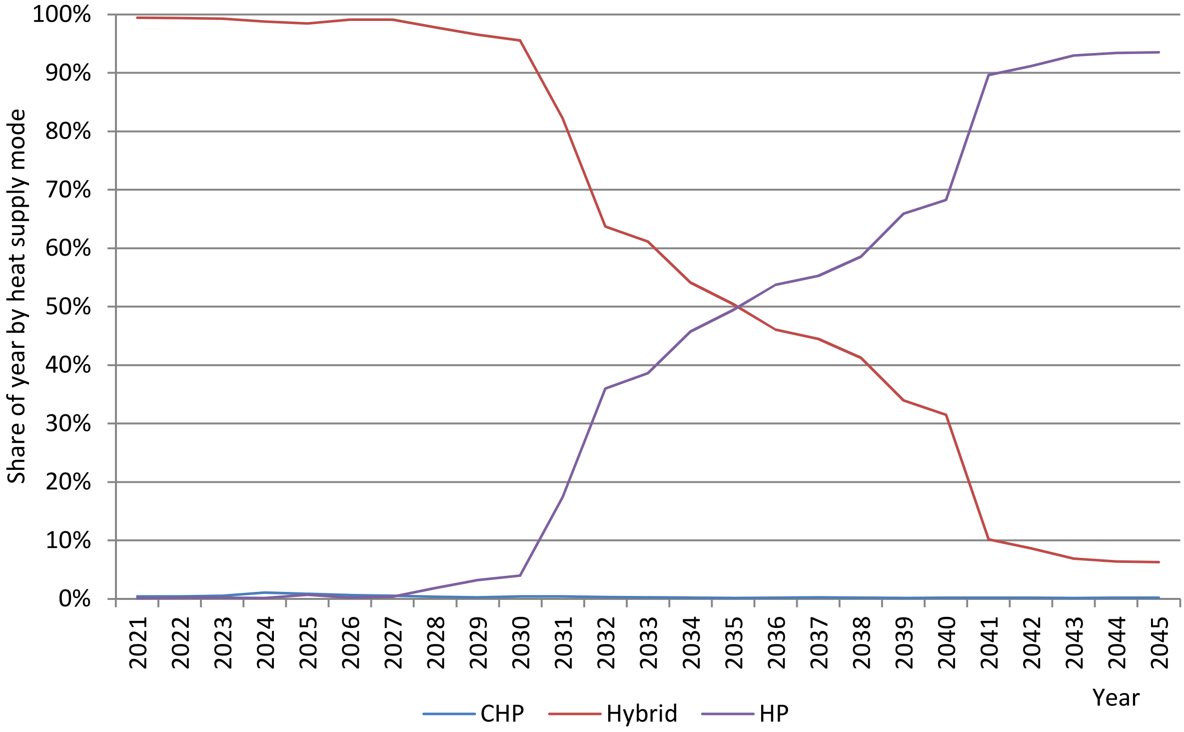


*Figure 15 -– Multi Vector Heat Supply Mode Share by Time, Low Electrical Price Volatility*

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); heat supply costs where electrical and gas costs are fixed to their annual averages are also included in this analysis; in this case the multi vector saving falls by almost 40%.

## 7.3 Case Study 3 – PiV fuel switching

### 7.3.1 ECCo Model Projected Parc and Demand

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

*Table 68 – 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 69 – 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 |

### 7.3.2 Oil to Gas Price Ratio

Oil and gas prices over the last 8 years are shown below, taken from MacroTrends.

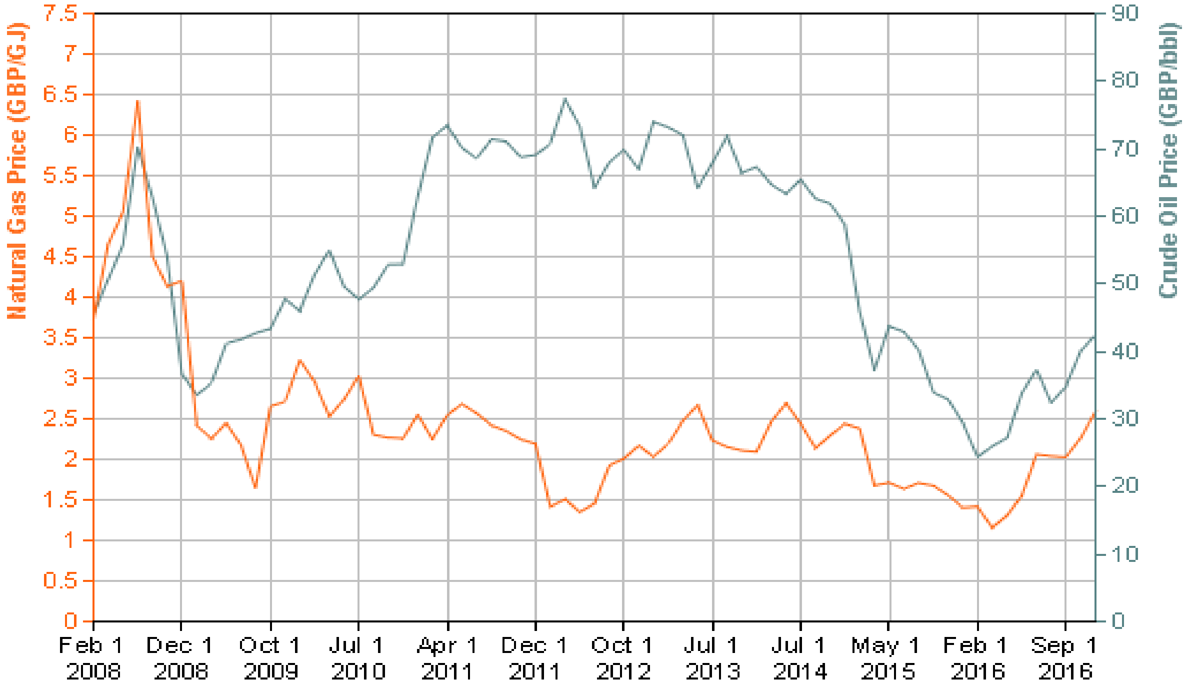


*Figure 16 – Historical Oil and Gas Prices (£/GJ gas and £/Barrel crude oil)*

## 7.4 Case Study 4 – Power to Gas – Transmission level RES to $H_2$ and RES to $CH_4$

### 7.4.1 Electrolyser Sizing as a Function of Total Renewable Generation

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.

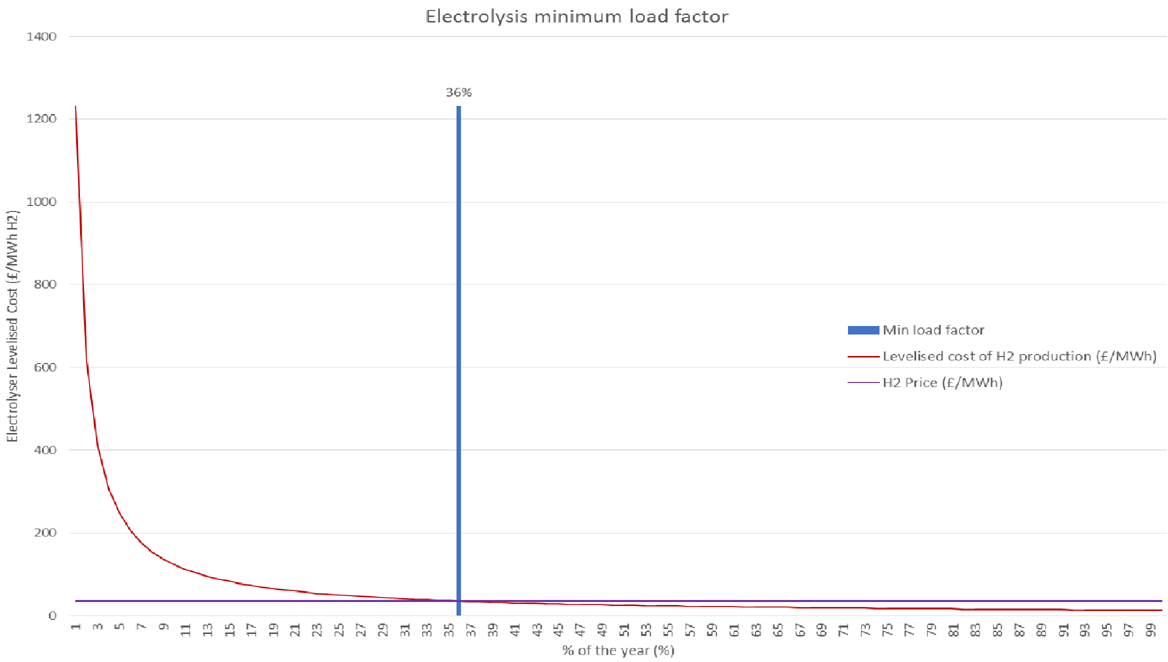


*Figure 17 – Minimum economic load factor of electrolyser- ESME V4.1 Ref Case*

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.

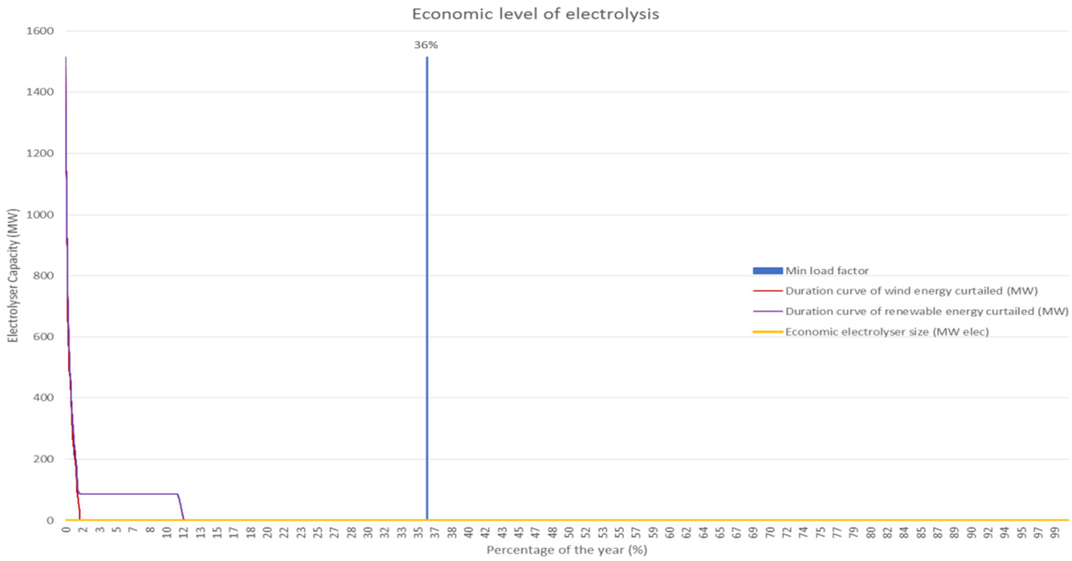


*Figure 18 – Economic size of electrolyser-ESME V4.1 Ref Case*

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

*Table 70 – 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.

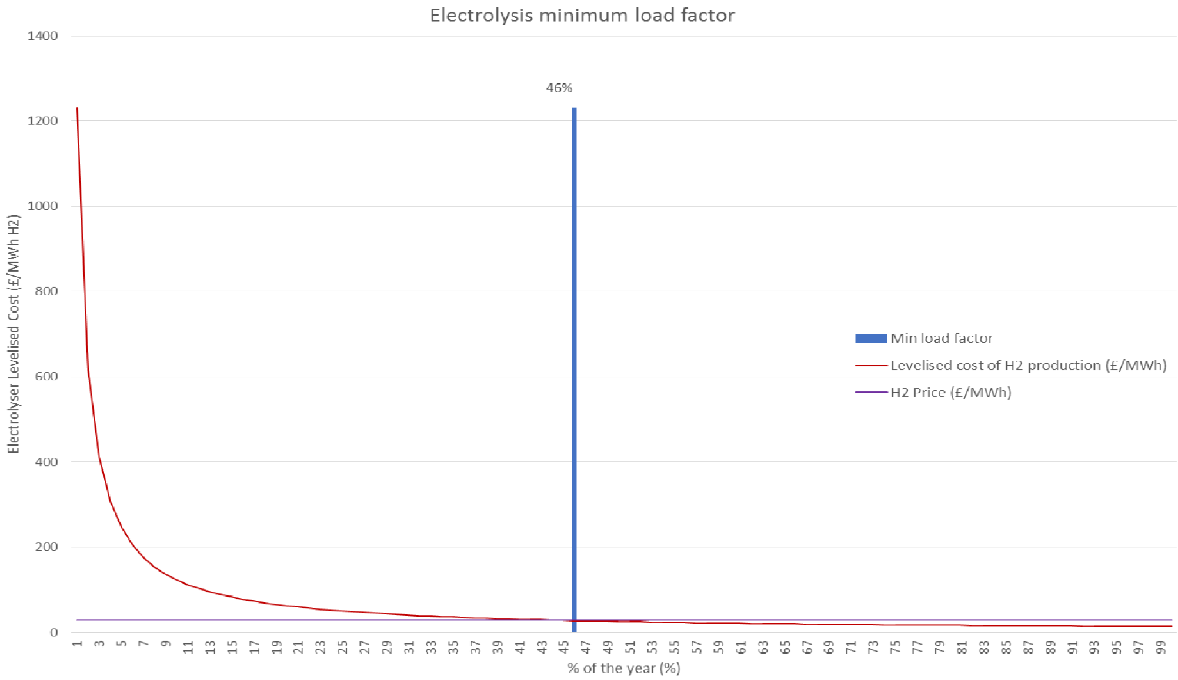


*Figure 19 – Minimum economic load factor of electrolyser- ESME Scenario 3 (High)*

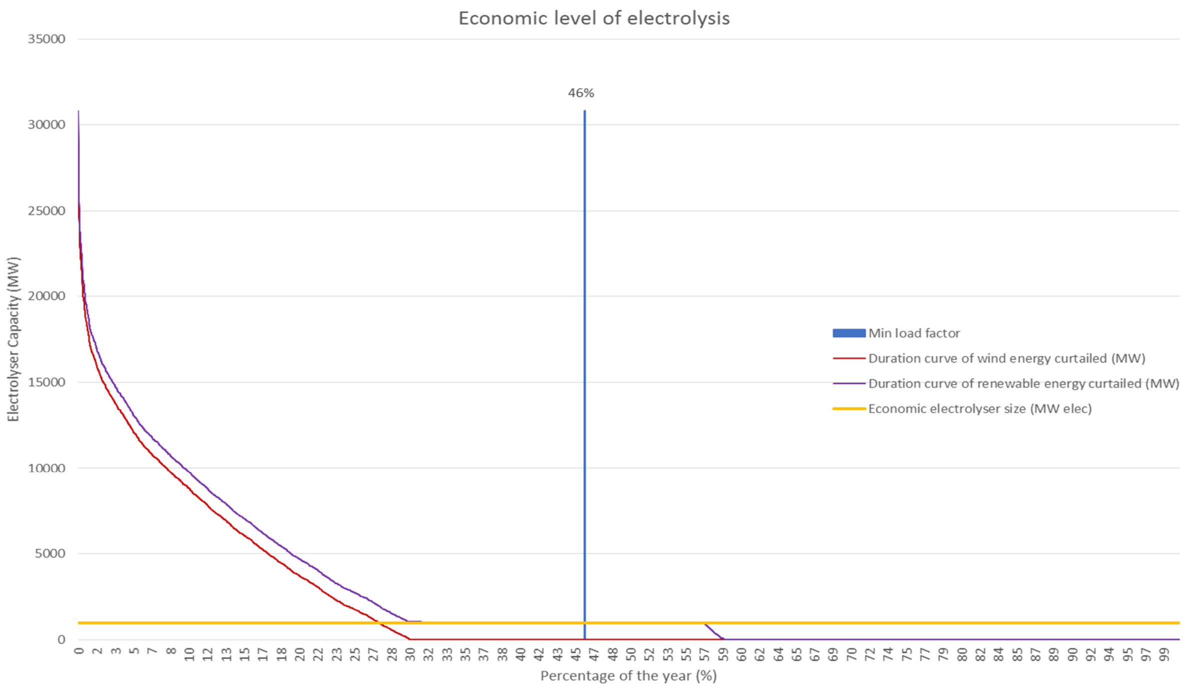


*Figure 20 – Economic size of electrolyser- ESME Scenario 3 (High)*

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.

### 7.4.2 Cost of $CO_2$ as a fuel for Methanation

The (environmental) cost of carbon for methanation is determined by whether:

- Whether the carbon would otherwise be vented or stored
- the SNG produced displaces natural gas use, or creates and meets additional demand

This analysis does not include other carbon costs, e.g. transportation.

*Table 71 – Carbon Cost Scenarios for Methanators*

| | |
|---|---|
| **Case A - Zero Carbon Cost:** | $CO_2$ is taken from a CCS facility and the SNG produced and injected into the gas grid displaces the 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, the net system carbon production is zero and 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, SNG produced and injected into the gas grid displaces the equivalent amount of natural gas. In this case, methanation provides a net reduction of carbon emissions at a system level and therefore has a negative cost. |
| **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. |

### 7.4.3 Single Vector Alternatives

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 72 – 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 |

### 7.4.4 Electrolysers Provision of Grid Regulation and Ancillary Services

The key conclusion from our analysis 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[81]. In addition, as part of the Aberdeen H2 Project, SSE published a report on the impact of electrolysis on distribution networks[82], 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 73 – 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)<br>~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[83] 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).

[81] "Novel Electrolyser Applications: Providing More Than Hydrogen", NREL, 2014

[82] "Impact of Electrolysers on the network, Part of Aberdeen Hydrogen Project", SSE

[83] 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 74 – Main balancing services types*

| Balancing Service Type | Relevance to current GB market | Response time | Response duration |
|---|---|---|---|
| **Frequency containment**[84] | 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.

[84] "Profiting from Demand Side Response", National Grid, Power Responsive, 2016

During those times, the electrolyser can:

a. Participate in the NG Demand Turn Up (DTU) service provision[85][86]; 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

[85] "Demand Side Opportunities", National Grid, Power Responsive http://powerresponsive.com/wp-content/uploads/pdf/power-responsive-dsr-product-map-glossary-161215.pdf

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.

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)[87].

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 26, 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 it reduces 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 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.

[87] 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.

## 7.5 Case Study 5: Grid power to hydrogen for a hydrogen network

### 7.5.1 Cost and Technical Characteristic Data

Case Study cost assumptions and technical data are given in the following table. The majority of the data are taken from ESME v4.1, apart from the following:

1. 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[88]. This aligns with the efficiency figure used in Case Study 4 where electrolysis was also examined.
2. 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 the NREL report[89].
3. $H_2$ 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.
4. To derive a figure for the cost of the transmission network 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 (190km).

*Table 75 – Economic and technical input assumptions in Base Case*

| Parameter | SMR | Electrolyser | $H_2$ salt cavern storage | $H_2$ transmission Pipe 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 | - |

[88] http://www.northerngasnetworks.co.uk/document/H21-leeds-city-gate/

[89] *Novel Electrolyser Applications: Providing more than just Hydrogen* (NREL)

### 7.5.2 Hydrogen Demand - Hourly Profile

Diurnal $H_2$ demand profiles are based on the heat demand profile from the Carbon Trust micro-CHP field trials data (for both domestic and non-domestic customers)[90]. 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[91]. Demand for a day in January is shown below.

Based on ECUK data, 63% gas demand is domestic and 37% non-domestic; 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.

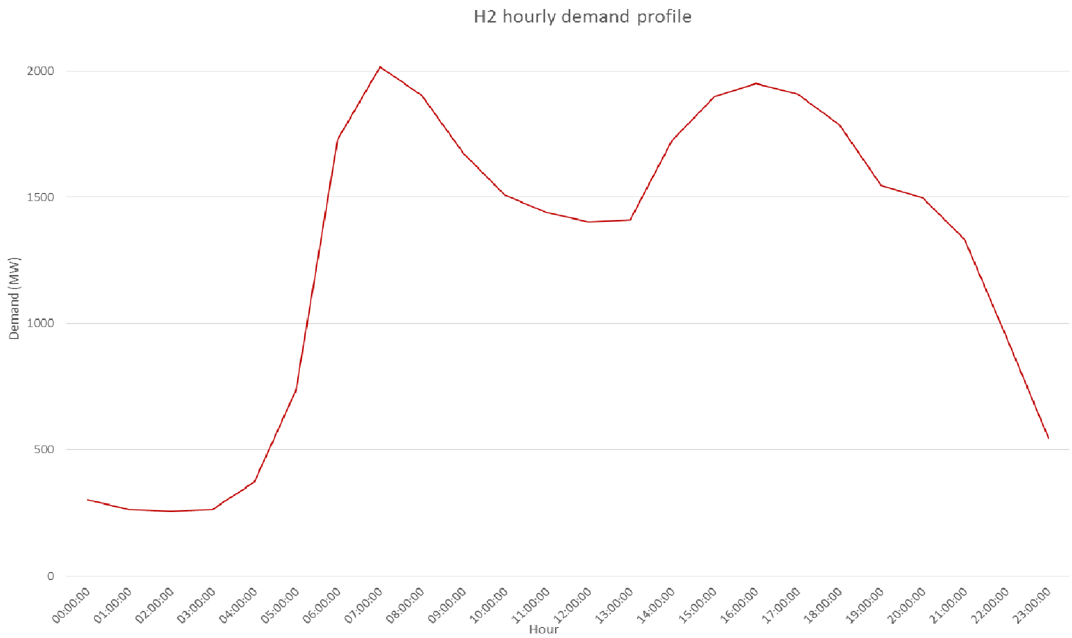


*Figure 21 – Hourly hydrogen demand profile for a January day*

### 7.5.3 Natural Gas and Electricity Price Profiles

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.

90 The hydrogen demand profile reflects the required flow at the meter point, implicitly accounting for any heat storage within buildings.

91 The diversification factors scale the peak values by 25% and 10% for domestic and non-domestic demands respectively.

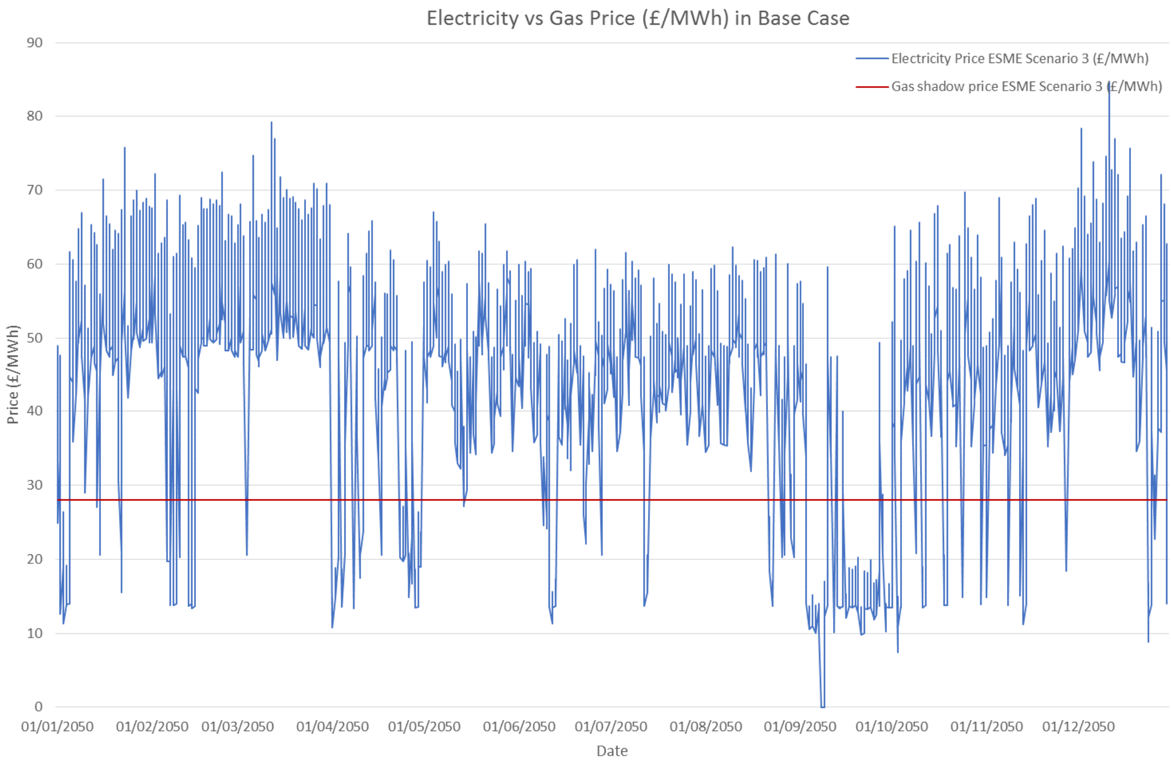


*Figure 22 – Electricity and Gas Prices Used in Base Case Scenario*

## 7.6 Case Study 6a – Power to heat – District heating

### 7.6.1 Renewables to Heat Networks – Geographical Analysis

The map below shows:

- potential locations where DH networks are likely to be built until 2050 (based on a geospatial analysis of heat demand density and points of potential supply[92])
- Existing wind farms and PV farms[93],

These give a sense of potential opportunities for synergy between wind farms and DH systems.

The best candidates for DH networks densely populated areas; the Greater London area, the North East and North West of England, the Midlands, and Yorkshire. The renewables dataset used includes 764 wind farms, (97% of which are connected to the distribution, and 3% 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.

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.

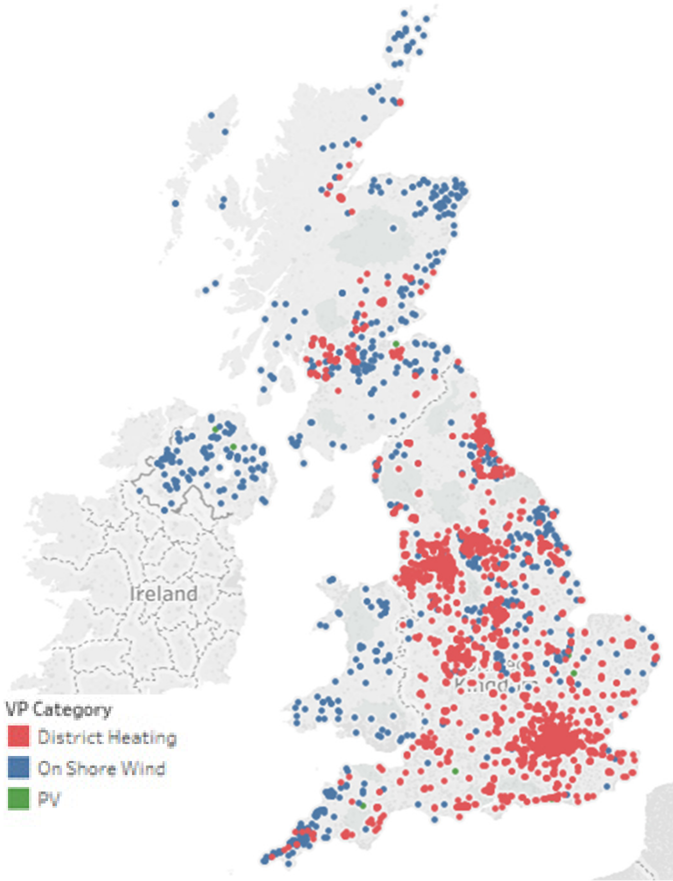


*Figure 23 – Future Potential DH Network Locations and Existing Wind and Solar Farms*

[92] Research on District Heating and Local Approaches to Heat Decarbonisation

[93] Existing UK wind and PV farms dataset available on http://www.variablepitch.co.uk

Figure 24 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[94], 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[95].

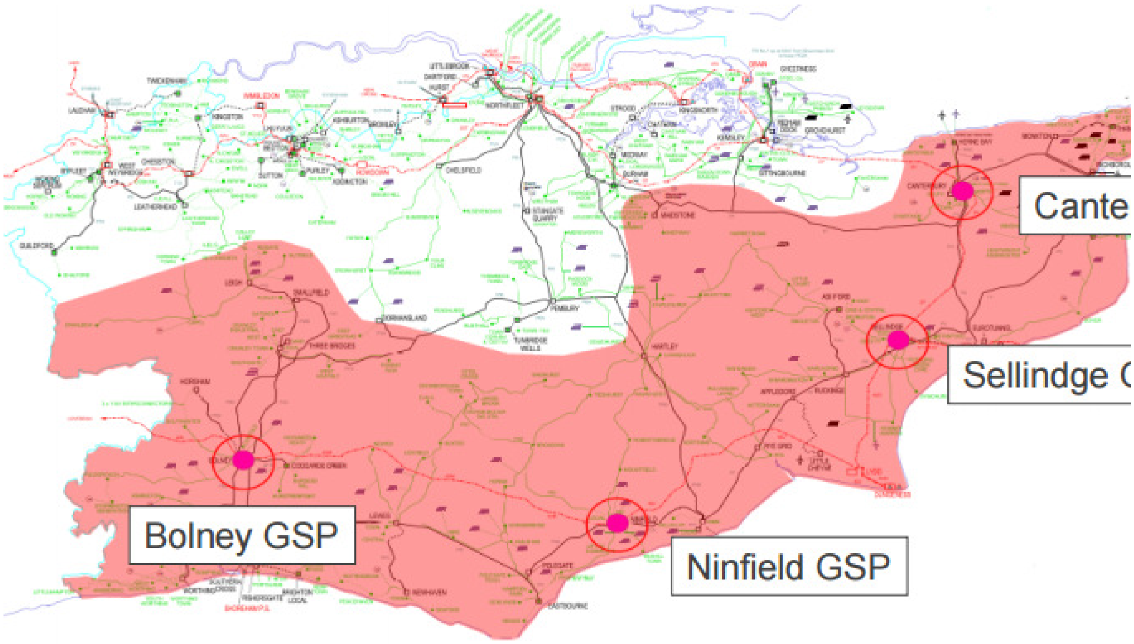


*Figure 24 – Constrained distribution network area in Southern Eastern Network (UK Power Networks)*

### 7.6.2 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.

[94] Distributed Generation Customer Forum slides, September 2016

[95] WPD, West Midlands Distributed Generation Constraint Map

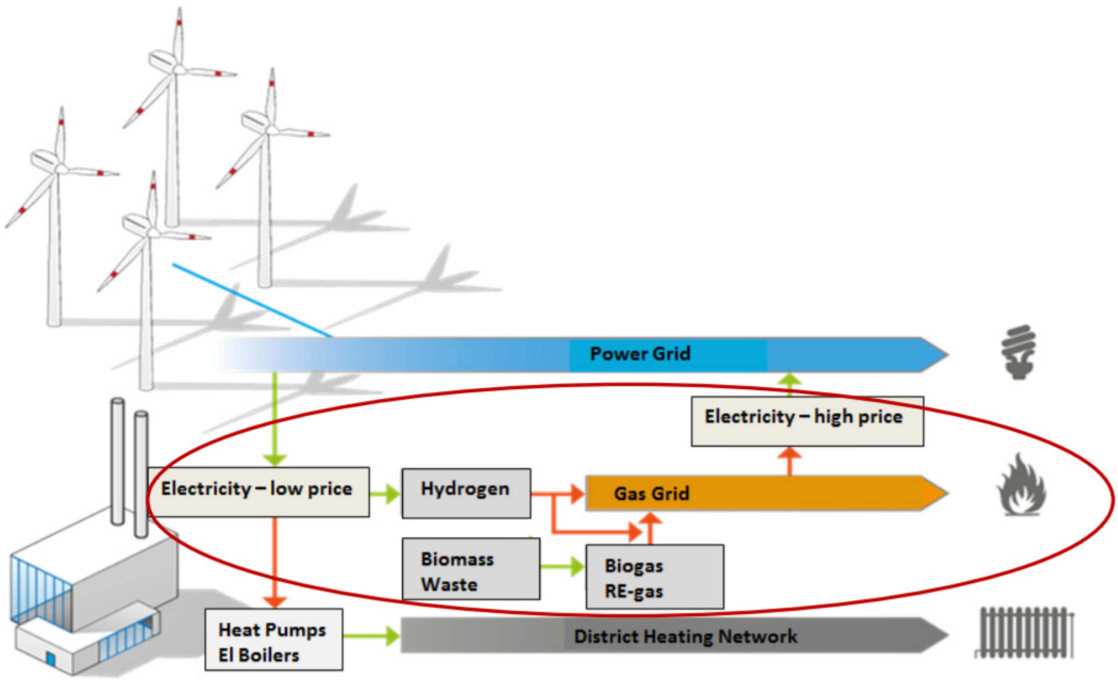


*Figure 25 – Danish district heating vision – a multi vector approach*[96]

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[97], 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.

[96] Danish Energy Agency, District Heating and Integration of Wind Power in Denmark

[97] Potential of Power-To-Heat Technology in District Heating Grids in Germany, Böttger et al, Energy Procedia, vol. 46, 2014

### 7.6.3 Cost and Technical Characteristic Data

The economic and technical assumptions 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[98], and the heat pump CoP is based on Element Energy's study on district heating[99].

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 76 – 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[100] | 1 | - | - |
| Charging/discharging efficiency (%) | - | 99 | - | - |
| Coefficient of performance (CoP) | 4[101] | - | - | - |
| Minimum time for full charge/discharge (h) | - | 1 | - | - |
| Economic lifetime (years) | 20 | 30 | 40 | 40 |
| Discount rate (%) | 8 | 8 | 8 | 8 |

[98] Potential for Thermal Storage to Reduce Overall Carbon Emissions from District Heating Systems

[99] BEIS - Heat Pumps in District Heating

[100] 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.

[101] Heat pump (CoP), fixed at 4 throughout the year, as ground-source heat pumps are less sensitive to seasonal temperature variation.

## 7.7 Case Study 6b – Power to heat – smart electric thermal storage (SETS)

### 7.7.1 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[102]). 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.

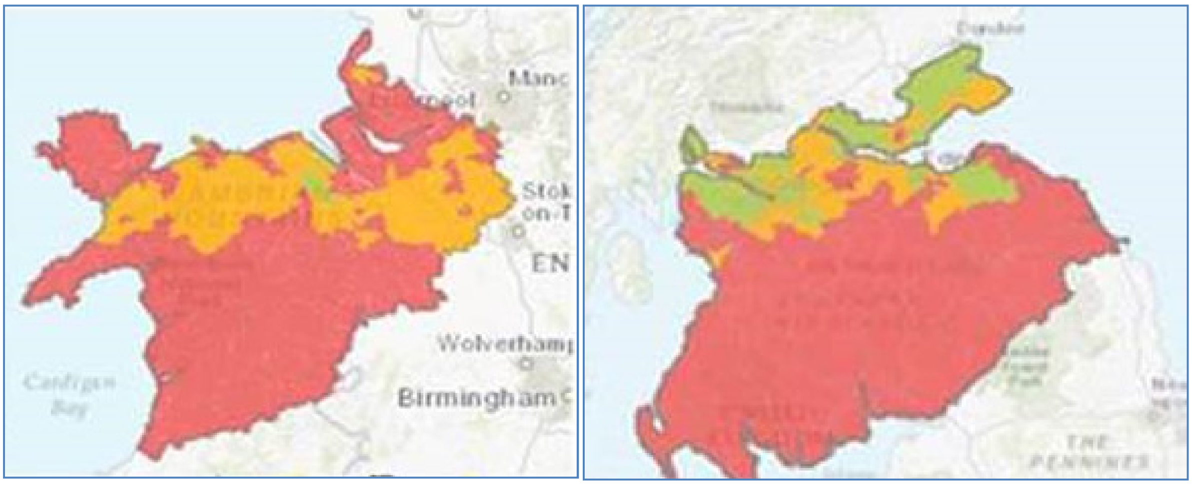


*Figure 26 – SP Energy Networks - Connection Constraint Heat Maps, North Wales & Scottish Borders.*

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[103]. 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[104] – to avoid local grid constraints).

[102] SP Distribution Heat Maps

[103] The Heat Policy Statement - Scottish Government

[104] 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[105]

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 77 – 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[106]. An Element Energy report for National Grid[107] 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.

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.

[105] National Grid - Demand Turn Up
[106] V-Charge Consultation Response to Ofgem
[107] Frequency Sensitive Electric Vehicle and Heat Pump Power Consumption

## 7.8 Case Study 7 – Energy from waste to electricity and biogas

### 7.8.1 Stochastic Price Generation

Adding a probabilistic element to power and gas price series allows us to determine the extrinsic option value[108].To illustrate this, consider two price series as shown in the figure below.

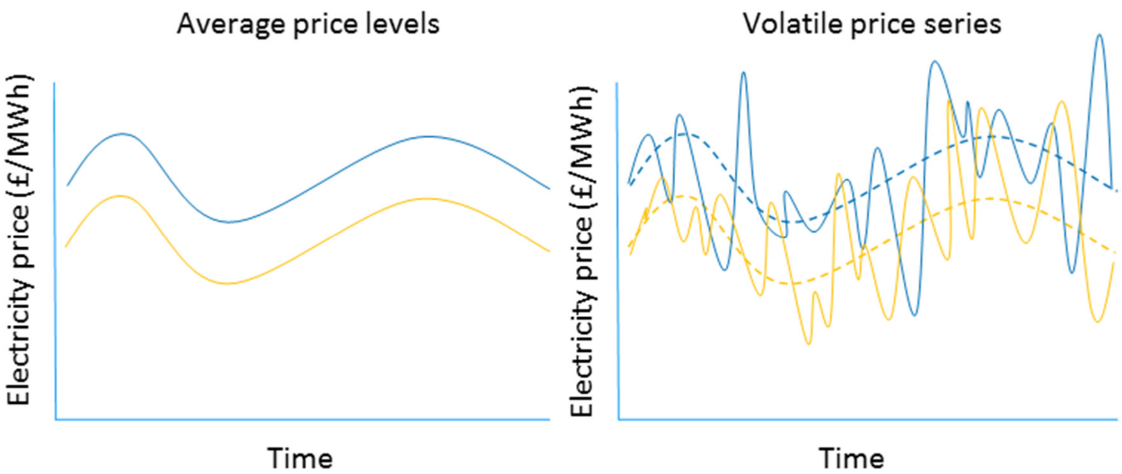


*Figure 27 – Pair of volatile price series*

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.

We 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. 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,
- 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.

[108] 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.

### 7.8.2 Case Study Model

Our model 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 comparing total yearly single and multi vector revenues; producing a set of 100 non-negative values, across which we take the average. This is then compared to the annuitized investment and O&M costs of the required multi vector add-on technology.

Hourly power and gas prices are taken from the ESME 2050 High Renewables Scenario (see appendix 6). When generating the stochastic power prices, some further randomness is added onto the signal, based on historical volatility and mean reversion of 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, since 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. This 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, 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.

The analysis carried out in this Case Study uses 100 stochastic simulations for electricity and gas prices which are shown below. The electricity price signal has high mean reversion since:

- price formation is closely linked to the plants' SRMC,
- supply and demand matching are possible in close to real-time.

Therefore, the signal tends to revert to the underlying deterministic pathway quickly.

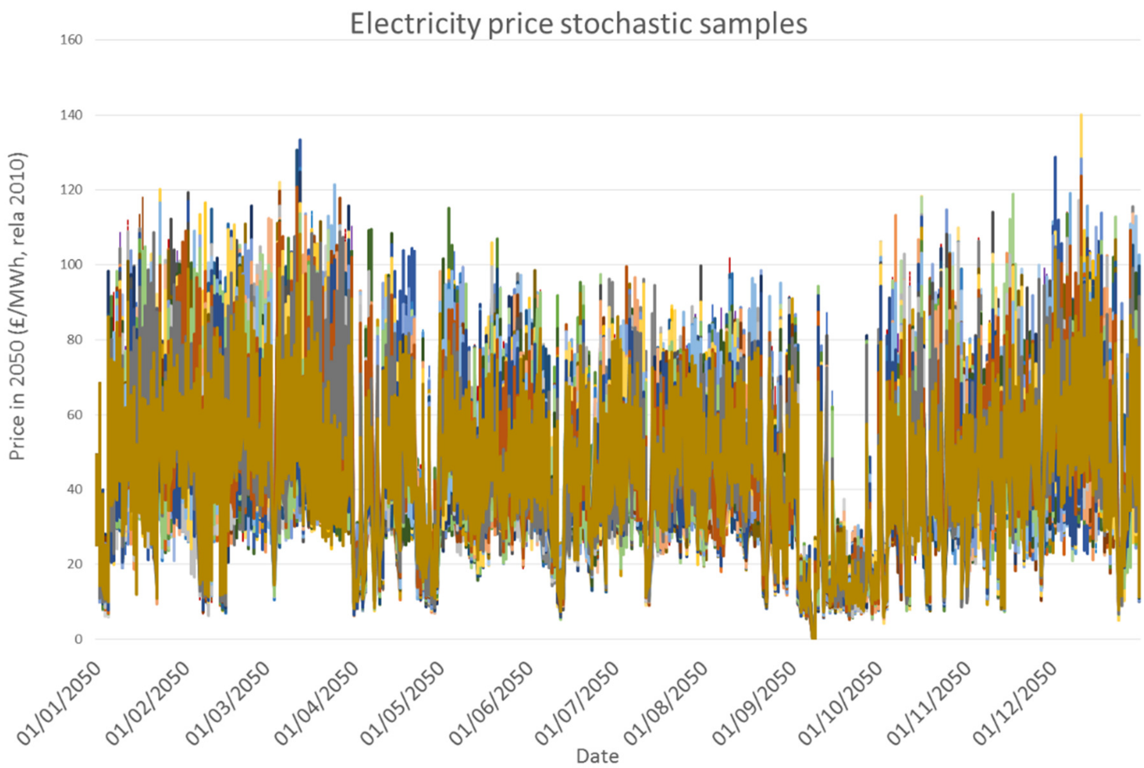


*Figure 28 – Base case probabilistic samples for electricity prices in 2050 (real 2010)*

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:

- a more diffuse set of price drivers for gas, including influences across a much broader geographic spread
- the strong influence of commercial and contractual arrangements
- influence of varying longer-term price views, given the availability of gas storage.

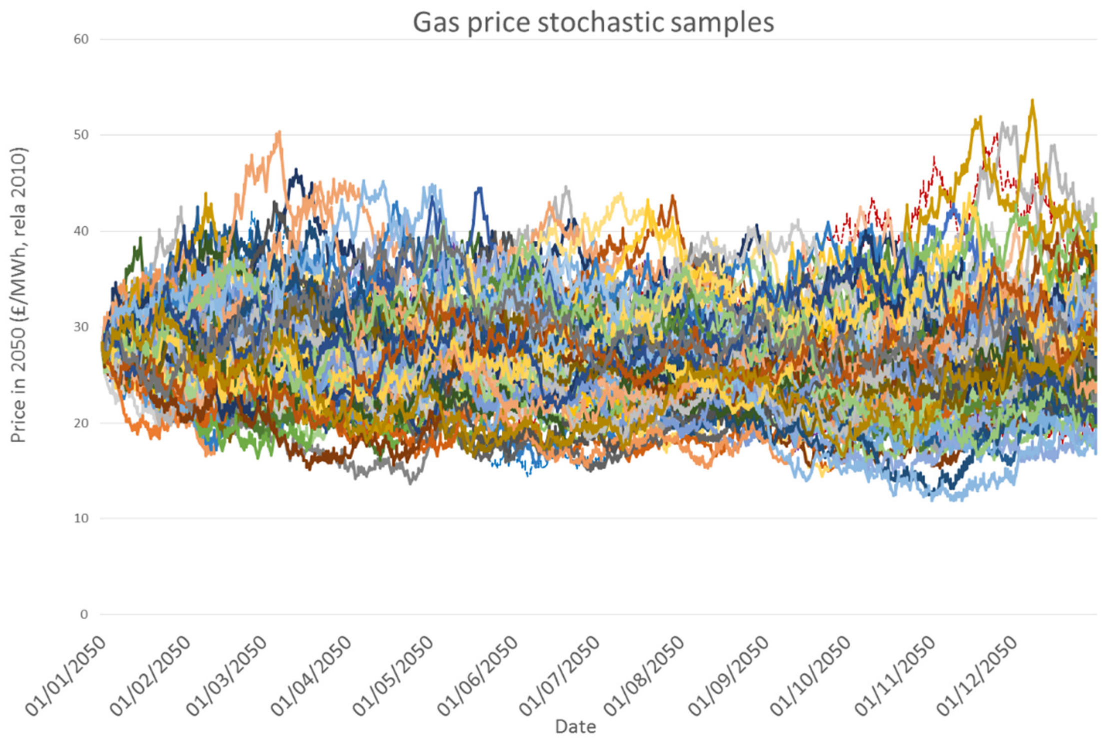


*Figure 29 – Base Case probabilistic samples for gas prices in 2050 (real 2010)*

The graph below shows the average power and gas prices over the 100 probabilistic scenarios generated (for each scenario, the correlation between the two signals is 15%).

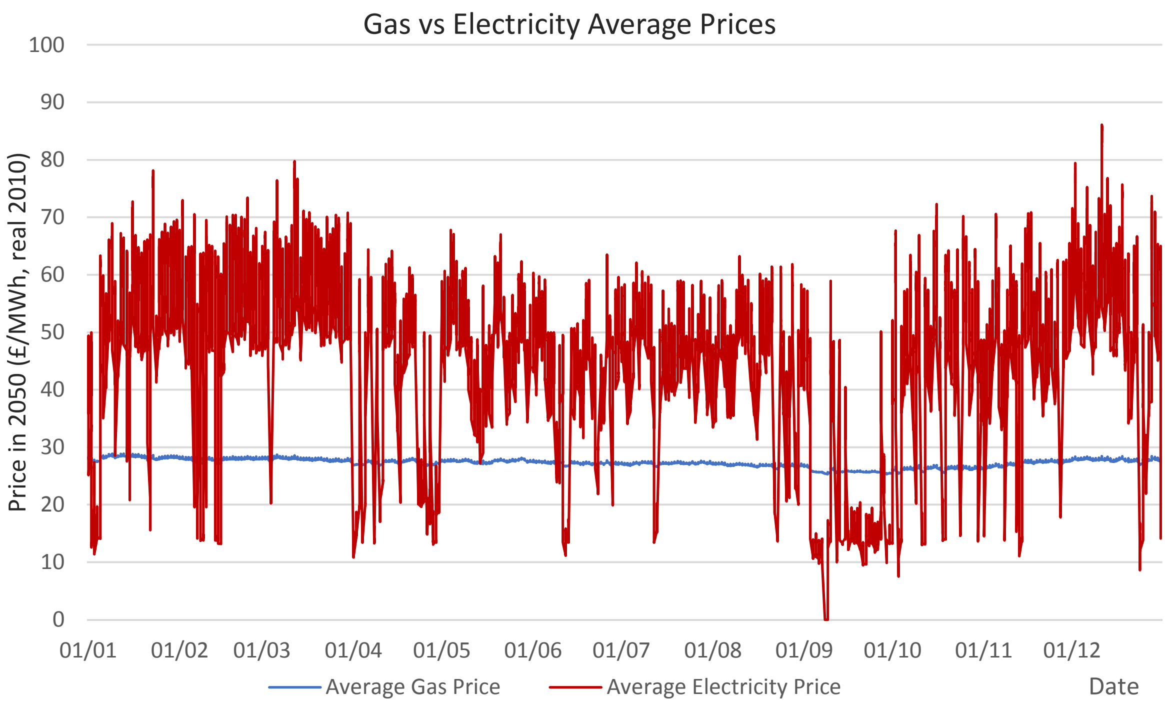


*Figure 30 – Base Case average electricity vs gas prices in 2050 (real 2010)*

### 7.8.3 Cost and Technical Characteristic Data

Model data are shown below.

*Table 78 – 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 (%)[109] | 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 |

[109] Efficiency figures quoted are based on MWh main output/MWh input waste ratio

AD efficiency assumptions are taken from ETI's bioenergy programme data.

- 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[110] (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.

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.

### 7.8.4 Grid Entry Unit Costs

The Grid Entry Unit (GEU) 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 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.

[110]Taken from conversation with Progressive Energy.

# 8 ESME Data

### 8.1.1 ESME 2050 Generation Fleet Scenarios

The three future generation mix scenarios used in Case Studies 3, 4 are shown below;

*Table 79 – ESME scenarios with -increasing renewables capacity*

| Generation capacity (GW) | ESME V4.1 Ref. Case | ESME Scenario 2 (Increased renewables) | ESME Scenario 3 (high renewables) |
|---|---|---|---|
| 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** |

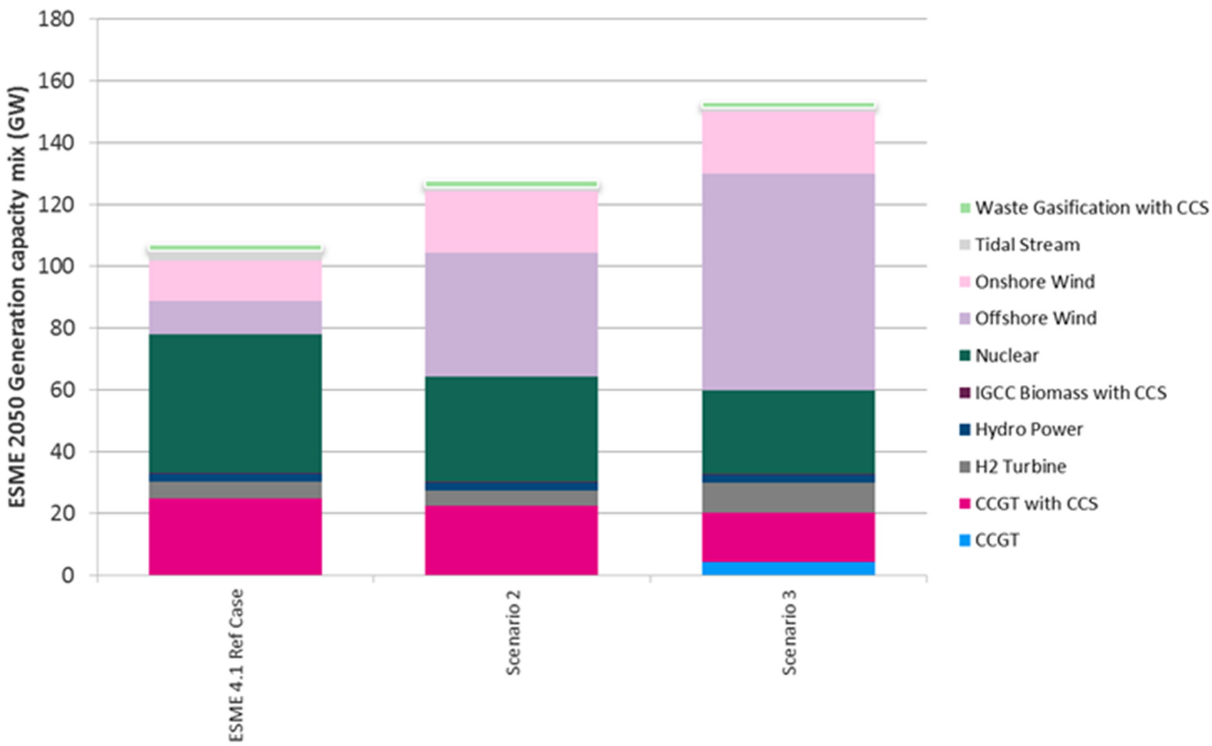


*Figure 31 – Generation technologies capacity mix per ESME scenario*

### 8.1.2 ESME Modelled Generation Fleet (2050 High Renewables)

A more detailed breakdown of generation mix for scenario 3 is shown below.

*Table 80 – 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** |

### 8.1.3 OCGT Parameters

Marginal kWe may be provided by OCGT; most likely without CCS. The parameters to determine SRMC and LCOE are shown below.

*Table 81 – 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% |

# 9 Summary of Assumptions and Data Sources

## 9.1 Case Study 1

Case Study 1 models the grid upgrade costs associated with the large-scale electrification of heat.

*Table 82 – 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. | 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 for both domestic and I&C users. | The same profiles are used for domestic and I&C demand, this likely slightly overstates peak thermoelectric demand. |

*Table 83 – Simplifying Assumptions*

| Parameter | Assumption | Comment |
|---|---|---|
| **Flow Temperatures** | Buildings constructed before 2004 are assumed to require a flow temperature of 70°C, new build a flow temp of 55°C | A flow temperature of 70°C may only be possible at the CoP values modelled using a $CO_2$ heat pump. |
| **GSHP and WSHP CoP** | Assumed to take a year-round value of 3. | |

## 9.2 Case Study 2

Case Study 2 considers district heat supply under a range of future energy system price forecasts.

*Table 84 – Case Study 2 Data Sources*

| Parameter | Reference Values | Comment |
|---|---|---|
| **Electricity and Gas Prices, Carbon Intensities** | Taken from Decarbonisation Scenario, described in appendix 8. | 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 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*. | |

*Table 85 – 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℃ | |

## 9.3 Case Study 3

Case Study 3 considers fuel switching of hybrid vehicles at times of electrical system constraint.

*Table 86 – 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 | |

## 9.4 Case Study 4

*Table 87 – 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 88 – 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/ |

## 9.5 Case Study 5

*Table 89 – 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. |
| **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. |

## 9.6 Case Study 6a

*Table 90 – 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, on the assumption 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 | |
| **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 | |

## 9.7 Case Study 6b – Power to heat – smart electric thermal storage

Case Study 6b assesses the value of Smart Electric Thermal Storage (SETS)

*Table 91 – Case Study 2 Data Sources*

| Parameter | Reference Values | Comment |
|---|---|---|
| **Electrical Price** | Taken from Decarbonisation Scenario, described in appendix 8. | 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. | |

## 9.8 Case Study 7

*Table 92 – 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<br>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<br>Waste to electricity: As per ESME v4.1 database for a Waste Gasification plant with CCS | |
| **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. | |

# 10 Longlist of Multi Vector Interactions

The following multi vector interactions or energy substitution options were identified, and subsequently presented to and discussed with the project steering committee on the 24th June 2016, before being whittled down to the short list shown in section 2.2.2.

- Heat pumps with peak load boilers
- CHP combined with a heat pump in a single building
- Non-electric generation serving a district heating system
- Substitution of electric process heating with gas / liquid fuel technology
- Fuel cell vehicle feeding electricity to the home
- PHEV switching to liq. fuel only running during high electricity price period
- PHEV displacing electrical demand with petrol, including (V2G)
- Range extender $H_2$FC vehicle – $H_2$ to recharge batteries at times of electrical system stress
- RES-to-Gas ($H_2$, $CH_4$) or DH
- AD/Gasification to CHP or Grid Injection
- $H_2$ from SMR or electrolysis into $H_2$ grid
- $H_2$ from pre-combustion CCS to power/transport/heat