BUROHAPPOLD
ENGINEERING

Toads Hole Valley District Heating

Toads Hole Valley Heat Network Study

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Glossary

Term	Definition
AD	Anaerobic digestion
ASHP	Air source heat pump
BAU	Business as usual
BEIS	Business, Energy & Industrial Strategy department (formerly known as DECC, any references to DECC have been replaced with BEIS)
BH	BuroHappold Engineering
BHCC	Brighton and Hover City Council
CHP	Combined heat and power
Carbon Intensity	The term carbon intensity of heat refers to the equivalent kg of CO_{2e} released when one unit of heat is produced
DECC	Department of Energy and Climate Change
DH	District heating
DHN	District heating network
DHW	Domestic hot water
GB	Gas boiler
GFA	Gross Floor Area
GSHP	Ground Source Heat Pumps
HIU	Heat interface unit
HNDU	Heat Network Delivery Unit
IRR	Internal Rate of Return
Main trunk network	Hot water pipes connecting the local energy centre to the heat density areas. The main trunk network in the study is taken to follow a major road which passes the masterplan.
NPPF	National Planning Policy Framework
NPV	Net Present Value
O&M	Operational and Maintenance
PPA	Power purchase agreement
PV	Photovoltaic
SDNP	South Down National Park
Secondary trunk network	Hot water pipes connecting the local energy centre to the heat density areas. The secondary trunk network in the study is taken to follow the potential minor roads of the masterplan
Service network	Hot water pipes connecting individual buildings to the trunk heat network.
SNCI	Site of Natural Conservation Importance
SPD	Supplementary Planning Document
THV	Toads Hole Valley
WSHP	Water source heat pump

1 Executive Summary

BuroHappold Engineering (BH) have been commissioned by Brighton & Hove City Council (BHCC) to undertake a high level techno – economic viability study of district heating opportunities on the Toads Hole Valley (THV) development site. Previous studies have identified the potential for district heating within THV[1], with the BHCC City Plan setting out an aim to incorporate infrastructure for supporting low and zero carbon decentralised energy and in particular heat networks for the site, subject to viability and deliverability.

1.1 Site layout

The site layout has been based on the THV vision document (2012)[2] and is used as guidance for the building densities and typologies across the site. **Figure 1—1** shows the site layout as this was taken from the vision document.

Figure 1—1 High level masterplan based on the vision document-scenario 1

After consultation with BHCC, three masterplan scenarios have been selected for analysis which reflect potential scenarios for the density of development across the site. Following the techno-economic assessment a fourth scenario was added to test the viability of a heat network, in which the network supplies a high density area of the site only. **Table 1—1** summarises the number of units/buildings and the housing density in each scenario.

[1] Brighton and Hove Renewable and Sustainable Energy Study, AECOM, January 2013
[2] http://www.toadsholevalley.co.uk/vision-document.html

Table 1—1 Masterplan scenarios

Description	Number of units/buildings			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
	Low density Meets DA7 allocation. As per Vision masterplan DHN* to all buildings.	**High density** Meets DA7 allocation. As per Vision Document masterplan. DHN to all buildings.	**High density** – Meets DA7 allocation and increases number of dwellings by 20%.	**Heat Network zone –** As Scenario 2. DHN does not extend to individual houses
Houses (units)	386	280	336	-
Flats (units)	314	420	484	420
Mixed use buildings (including flats and community facilities) – buildings	-	4	4	4
Business – buildings	5	5	5	5
Community hub –buildings	3	-	-	-
School - building	1	1	1	1
Housing Density (Dwellings per Hectare -DPH)	**53**	**65**	**65**	**84**

*DHN: District Heating Network

For the purposes of this feasibility study, the DH scheme that is proposed for the THV site is a retail scheme. This means that the operator or the manager of the scheme is responsible for final delivery to the individual customer (i.e. each dwelling or flat, or business unit). The DHN operator responsibilities are proposed as follows:

- Energy centre installation, maintenance and replacement
- Heat network installation and maintenance
- HIUs installation, maintenance and replacement
- Heat metering installation and maintenance

1.2 Justification of district heating as an alternative to gas boilers

The premise for investigating district heating (DH) is that it can deliver heat to the customer at a price competitive with conventional solutions and return an acceptable commercial performance for the operator. An investigation was conducted to demonstrate the true cost of heat and commercial competitiveness of a DH scheme against a boiler-only Business As Usual (BAU) case, i.e. assuming all dwellings on the site generate heat via individual gas boilers.

It was found that the marginal cost of heat generation for the DH is 10.8p/kWh per 3-bed town house (applicable to all scenarios), as compared with the BAU case of 13.7p/kWh.

The marginal cost of heat generation for a non-residential use (i.e. 5,000m^2 of office space) is 8.6p/kWh, as compared with the BAU case of 11p/kWh.

These prices assume that the electricity that is generated in the gas fire CHP plant is sold back to the grid at a price of 5.5p/kWhe for all the scenarios.

The BAU and DH cost of heat indicate a very small marginal profit that can be achieved through the DHN operation, Should a DHN be installed on the site the network operator could therefore charge each residential consumer up to 11.7p/kWh and each non-residential consumer up to 9.3p/kWh , so that the DHN still generates profit for each unit of heat delivered. Both the residential and non-residential variable heat prices include standing charges and are 15% lower than BAU marginal cost of heat.

This demonstrates that DH is a viable option on a cost of heat basis for the THV development albeit with a small margin. DH would provide low-carbon heat to residences for meeting the development's carbon targets, whilst also generating revenue for the network operator. The financial performance is investigated in the economic modelling.

1.3 Energy demand and supply assessment

The heat demand assessment of each scenario was carried out applying appropriate benchmarks for new buildings. From the heat demand assessment, heat demand profiles were created and used to inform the technical modelling process and plant selection.

The heat source assessment shows that the site has potential for multiple technologies as technical solutions, including gas fired combined heat and power (CHP), anaerobic digestion (AD) CHP, ground source heat pumps (GSHP) and biomass plant. AD CHP plant in particular was considered since proposals for an AD plant are being investigated by Brighton & Hove Energy Services Company (BHESCo) to the west of the THV site at Hangleton Bottom. A GSHP scheme could make use an existing 85m borehole to the south east of the site, subject to condition survey, testing and Environment Agency approval.

All the alternative technology options have significantly lower CO_2 than a conventional gas boiler approach based on 2015 emissions factors for electricity and gas. **Figure 1—2** illustrates the carbon equivalent emissions for the low carbon heat technologies (columns), which change due to reducing electricity emission factor, and for the gas boilers (indicated by the red line) which is constant.

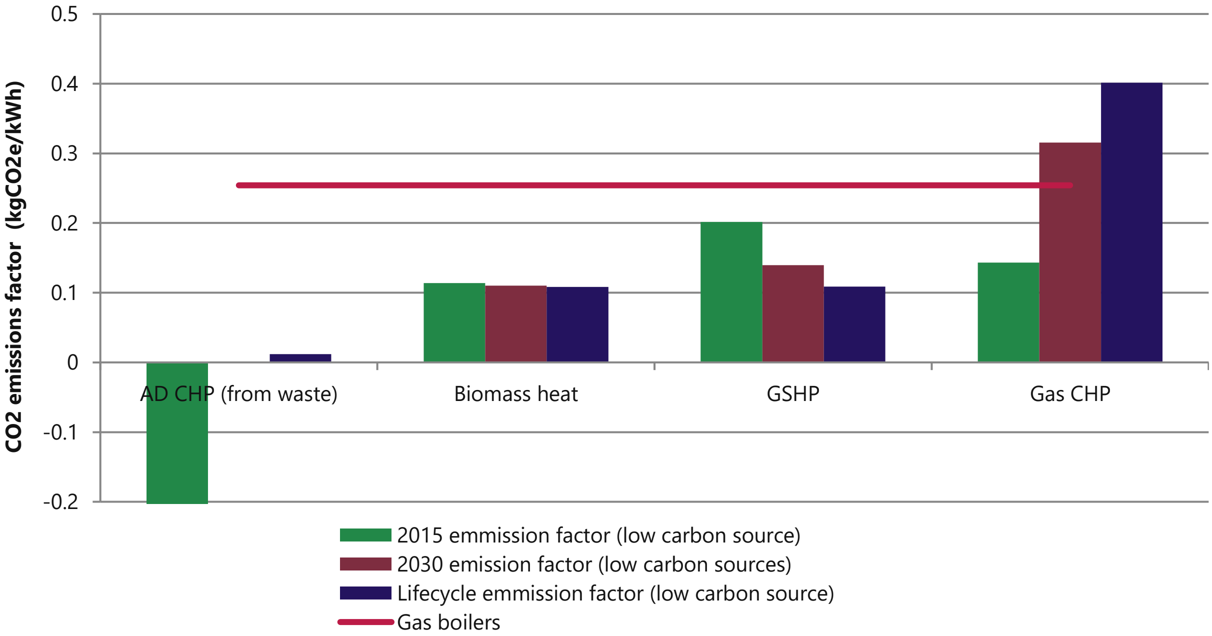

Figure 1—2 Carbon emissions: kg CO_2 per kWh of heat

Gas fired CHP has been chosen for the purpose of exploring opportunities for the District Heating Network (DHN) as it is a proven mature technology which is cost competitive, and can deliver short term carbon savings as a transition technology to kick-start a network.

GSHP, AD gas and biomass could prove to be feasible heat sources after further investigation, optimisation and de-risking.

For instance, pending proof of ground conditions, a GSHP open loop system would be more efficient combined with cooling of commercial buildings by using a seasonal heat storage strategy. This could be a closed loop GSHP or open loop, thereby making use of the existing well and an additional borehole. In the area of THV there are good aquifer resources for open loop systems. Whilst there is no information on the localised typical aquifer flow rate, if assumptions are applied, estimates can be made on potential yields There could be sufficient heat yield to supply approximately 70% of the baseload for scenarios 1 and 2 and 100% for scenario 4. An additional borehole would be needed for groundwater rejection.

AD CHP could form part of a long term transition, supplying bio-methane to the gas CHP to deliver carbon negative heat. The heat could be deemed carbon negative due to offset of natural gas and grid electricity. Due to the current uncertainty around a local AD plant, the integration of this could be considered for later integration when the plant is running and yields are proven (possibly 10-15 years).

The energy centre location should be considered to allow for potential routing of a gas transmissions pipe from the AD plant in the future and also for fuel delivery in case of biomass heating.

1.4 Technical modelling

The network modelling results in conjunction with the heat demand assessment indicated that all four scenarios have a low heat line density of ~0.3-0.7MWh/m. Although this is relatively low in comparison to typical schemes, the specific economic viability is a combination of site capital costs, operating costs and revenue.

EnergyPRO (an energy balance modelling software package) was used to assess the optimum size of the CHP and thermal storage for each scenario. The results of the technical plant sizing are summarised in **Table 1—2** . Top-up gas boilers are required to meet the peak demand of the site which will not be met by the low carbon heat source.

Table 1—2 Summary of technical modelling results

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Peak demand (kWth)	4,700	5,000	5,500	4,000
Annual heat supply– including losses (MWh/year)	3,889	4,196	4,847	2,788
Primary heat plant	400kWth gas CHP	400kWth gas CHP	527kWth gas CHP	286kWth gas CHP
Thermal Storage (m^3)	100	100	100	100
Top-up gas boilers (kWth)	5,275	5,275	5,275	4,100
Network length (m)	12,027	8,655	10,196	3,622
Heat line density (MWh/m)	0.32	0.48	0.48	0.77

1.5 Economic modelling

Project lifecycle costs

An assessment has been made of high level project lifecycle costs for each scenario to inform the business case for progressing different options. Cash flow models have been developed over a 25 year period (typical life of counterfactual boiler plant), given a discount rate of 3.5%. A 40 year period has been also been considered due to the longer expected life of a district heating network.

Network costing

Network costs are split into pipe costs and civil costs. Civil costs depend on the type of trench digging (soft or hard) and on the landscape (i.e. greenfield, urban environment, co-location with other utilities). Civil costs have been estimated based on soft dig to be laid by a multi-utility contractor in a shared utility trench. As a result the apportioned civil works for district heating have been estimated at 15% of the cost that would be required for DH 'standalone' installation in greenfield sites. This 15% derives from the co-location of 5 utilities (heat, electricity, communications, water, sewage) and a 5% contingency for each utility.

Avoided costs - Gas boilers and PV installations

The avoided costs are the costs that would be required to account for a conventional gas boilers installation, gas network connections and to offset carbon emissions for meeting the development target of 19% carbon reduction improvement against Part L 2013 for residential development and BREEAM excellent for non-residential developments.

The gas boiler avoided costs for the residential development equate to £1500 per dwelling, and for non-residential buildings an equivalent boiler cost of £80 per kW of heat has been used.[3] The gas network connection cost was taken as approximately £600/connection using Southern Gas Networks connections charging methodology for new connections.

Offset PV costs have been estimated and included as contributions into the conventional reference scheme.

Heat and Power sales

Following the comparison of the DH marginal cost of heat and the BAU marginal cost of heat for residential and non – residential developments the heat sales prices were set at 11.7p/kWh and 9.3p/kWh, respectively. These prices allow some margin for profit generation for the DHN operator and provide 15% savings in the cost of heat for the end consumers.

The study assumes that the power that is generated in the gas fired CHP plant is sold back to the electricity grid at 5.5p/kWh. There is a potential opportunity for the site developer to negotiate a Power Purchase Agreement (PPA) with an appropriate consumer to sell all CHP-generated power. Hence, the power could potentially be retailed higher at ~9p/kWh via a 'private wire'. This power price is ~20% below the quoted BEIS (2016) price, i.e. lower than grid electricity price in order to make PPA attractive for purchaser of CHP-generated power. No consumer has been identified at this stage but should be investigated during further project development.

[3] Spon's 2015, non-domestic gas boilers

Plant replacement fund

The plant replacement fund has been proposed to allow for the replacement of gas CHP engines and gas boiler plant at the assumed end of life. The cost of the replacement cycles has been equally distributed to the lifecycle of the plant and is included in the annual OPEX.

Financial modelling – base case

A summary of the economic modelling is shown in **Table 1—3**, which includes the capital costs for the DHN, the BAU avoided costs, the net capital costs, the year 1 net revenue, NPV and IRR. All the OPEX costs for the BAU case will be paid by the homeowner following the initial installation.

The results indicate that none of the scenarios deliver a positive NPV and a high IRR under the base case financial modelling. Although all the scenarios generate positive annual revenues from the DHN operation, the profit is marginal. The marginal profit derives from the operational costs that are included in a retail scheme where the heat network operator is not only responsible for the replacement and the maintenance of the energy centre and the heat network, but also for each individual HIU that is installed to deliver heat to the final consumer.

Table 1—3 Summary of costing and financial modelling results

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
DH scheme				
Energy centre cost (£)	1,625,000	1,625,000	1,933,000	1,373,000
Network cost (£)	2,694,000	1,832,000	2,142,000	709,000
Connection costs (£)	1,978,600	1,989,600	2,301,600	1,261,600
Gas boilers avoided costs (£)	-1,247,600	-1,247,600	-1,427,600	827,600
Gas network avoided costs (£)	-421,000	-422,000	-492,000	258,000
PV avoided costs (£)	-1,009,000	-1,125,000	-1,222,000	871,000
Total net capital cost (£)	3,620,000	2,652,000	3,235,000	1,387,000
Year 1 OPEX (£)	506,600	525,600	617,100	300,000
25 year NPV at 3.5% discount factor (£)	-2,859,300	-1,633,600	-1,874,900	-886,100
25 year IRR	-8.1%	-4.2%	-3.5%	-4.6%
BAU				
Gas boiler costs (£)	1,247,600	1,247,600	1,427,600	827,600
PV installation costs (£)	421,000	422,000	492,000	258,000
Gas network connections costs (£)	1,009,000	1,125,000	1,222,000	871,000

1.5.2 Sensitivity testing

Sensitivity analysis has been completed with the following input variations to review potential improvements to the projected economic viability:

- Increase in heat sales price to equal the BAU cost of heat
- Private wire electricity sales at 9p/kWhe
- 30% reduction in pipework costs (plastic pipework vs. steel pipework)
- Increase in model lifetime to 40 years
- +/- 20% variation in capital costs due to potential realised installation and construction costs
- Introduction of a grant to enable 5% IRR

Table 1—4 summarises the key results of the sensitivity testing that significantly improve the performance of the scheme compared to the basecase modelling. It also summarises the grant which would be required to get a 5% IRR in each scenario. The 5% IRR is selected as an indicative appropriate level of return to allow for modelling.

Table 1—4 Summary of key financial modelling sensitivity testing

	Model lifetime	IRR Basecase	IRR with private wire	Grant for 5% IRR	CAPEX
Scenario 1	25	-8.1%	-0.7%	£ 3,060,000	£6,200,000
	40	-3.5%	2%	£ 2,900,000	
Scenario 2	25	-4.2%	3.1%	£ 1,850,000	£5,400,000
	40	-0.6%	5.0%	£ 1,650,000	
Scenario 3	25	-3.5%	3.7%	£ 2,130,000	£6,300,000
	40	-0.1%	5.4%	£ 1,900,000	
Scenario 4	25	-4.6%	1.9%	£ 985,000	£3,350,000
	40	-0.9%	4.0%	£ 900,000	

Scenario 3 returns the best results indicating that increased unit numbers and therefore density can improve financial performance.

The results indicate that the introduction of electricity sales through a private wire significantly increases the performance for scenario 2 to 4. Potential consumers could include the commercial development and/ or the school but further consultation would be required to confirm the potential.

1.6 Carbon Dioxide (CO_2) savings assessment

The CO_2 emissions target for THV is aligned to a 19% reduction improvement against Part L 2013 for new build residential, and BREEAM excellent for non-residential developments which equates to ~25% carbon reduction against the baseline[4].

The carbon assessment has been conducted for the following THV energy supply options:

- Baseline:
  In this solution individual gas boilers are used and minimum energy efficiency measures are applied to in order to comply with Part L 2013. This solution does not meet the THV development CO_2 requirements.
- Fabric Improvements:
  In this solution individual gas boilers are used and fabric improvements against Part L 2013 standards are proposed. This solution does not meet THV development CO_2 reduction targets.
- BAU:
  This is the BAU case for THV as it has been described in section 3. Individual gas boilers are used alongside solar PVs to meet the THV development carbon targets. The amount of PVs that are required in the BAU case (individual gas boilers and PVs) to meet the CO_2 targets for the THV development are:
    - Scenario 1: 4,400m² of PVs.
    - Scenario 2: 4,900m² of PVs.
    - Scenario 3: 5,400m² of PVs.
    - Scenario 4: 3,800 m² of PVs.
- DH solution
  Gas CHP and peak load gas boilers are used for heat supply, summarised as follows:

[4] http://www.breeam.com/breeam2011schemedocument/content/06_energy/Ene01_general.htm

- The DH option is well above residential development's minimum target for all scenarios, achieving an approximately 35% decrease in carbon emissions of heat against the baseline for the residential developments.
- Commercial buildings have a high proportion of electrical loads and therefore less improvement in CO_2 savings performance is observed. Measures to improve non-residential performance include energy efficiency measures on lighting and electrical devices.
- The achievement of the CO_2 emissions target can be also achieved with the DH options through integration of renewable fuel sources to create heat. Financial modelling for these options has not been covered in this study, but it is recommended that more detailed feasibility work investigate this in order to enhance the CO_2 performance of the scheme. This could offer opportunities to transition to a zero carbon or nearly zero carbon heating scheme if a viable renewable fuel source can be identified for the site.

1.7 Delivery Roadmap

The commercial considerations for implementing the DH solution centre on key factors for BHCC and the developer to review and understand. These include:

- Drivers – what are the underlying drivers for BHCC to encourage the developer to deliver a DHN
- Viability of the business case – What are the expectations of the developer for returns, or potential for private sector involvement.
- Commercial structure – options for procurement include self-delivery by the developer, 3rd party energy service company (ESCO) or a joint venture. An initial review of the projects commercial performance indicates that involvement from BHCC could assist in improving the economic viability and de-risking the scheme.
- Funding – further investigation of additional funding to help deliver the scheme.
- Delivery programme – coordination with the development phasing.

1.8 Design Guidance

Design guidance has been developed for future inclusion in a Supplementary Planning Document for the area. Key aspects of the design guidance include:

- Energy Strategy recommendation
- Development density and Heat network zone
- Energy Centre
- Heat Sources
- Phasing
- Pipe network
- Buildings services design
- Network temperatures
- Town house solution
- Customer protection Scheme

1.9 Conclusions

Since development plans are not yet defined, this techno-economic assessment models hypothetical development for the THV site. Once layouts and densities are known, modelling generated for planned development will be able to reflect more closely likely techno-economic solutions and costs.

The techno-economic assessment of the heat network on the THV site shows that:

- The site has potential for a long-term transition away from fossil fuels with multiple potential sources. The installation of a district heating scheme at this stage can facilitate an easier transition to a low or zero carbon solution in future. All heat sources considered have significantly lower emissions than a BAU solution utilising gas boilers for heating and 2015 electricity emissions factor.
- Based on the City Plan Policy CP8, the DH option is well above the residential development's minimum carbon reduction target for all scenarios. Commercial buildings show reduced improvement in carbon savings performance due to low relative heat load. Further measures to improve non-residential performance include energy efficiency measures on lighting and electrical devices. The achievement of the carbon emissions target can be also achieved with the DH options through integration of renewable fuel sources to create heat.
- The masterplan base case scenarios under the financial framework do not demonstrate an attractive business case without further support. However, sensitivity testing reveals that the business case can be improved to achieve attractive IRRs of ~5% in Scenarios 2, 3 and 4. Improved viability depends on:
    - the heat sales price
    - opportunity for private wire.
    - Cost reduction through combined utility installation

  - Or in combination with external funding e.g. Heat Network Investment Project (HNIP) contribution to the network, a more economically viable scheme could be created.
- A 20% increase in residential units (scenario 3) improves the performance of the scheme marginally compared to scenario 2, which has the same residential development density.

The viability of the heat network is highly dependent on:

  - CAPEX – assumption that the DH network will be installed by a multi-utility contractor in a shared utility trench. This will reduce the civil costs for the DH pipework versus a standalone network installation.
  - Heat density - the proposed heat density of the THV site is not particularly high, since the majority of the developments are houses or low rise blocks of flats. A higher density development could improve the performance of the DH system.
  - Heat and power sale prices – the assessment shows that the DH can be competitive versus BAU heat cost.
  - Available fund or possibility to reduce capital cost.
  - Phasing –The heat network should run in parallel with the development's phasing and the other utilities. This approach could help match capital drawdown with the development programme in the initial phases of the development supporting solution flexibility.
  - Final masterplan –The final scheme could have different results on final building typologies, the design and the size of the heat network. which would have impact on the viability of the scheme.

1.10 Next steps

The next steps to progress the DH project, considering risks and uncertainties, include heat supply considerations, actions from the BHCC and actions from the developer.

Heat supply considerations:

- Gas and power utility capacity checks should be progressed to understand existing supply opportunities.
- To progress a GSHP open-loop system further steps would require proving of ground conditions, outline steps include:
  - Borehole condition survey and testing to accurately estimate the heat supply potential;
  - Environment Agency (EA) consultation to hold a licence for groundwater extraction from the borehole and rejection;
  - Pump test to accurately estimate the heat supply potential;
  - Viability of low temperature heating systems within the buildings and for network.
  - Drilling another well at a minimum distance of 100m from the existing well would be required for re-injecting the water back to the ground.
- In case a GSHP closed loop system is taken forward a thermal responsive test would be suggested to understand the ground heat yield and optimise the GSHP design accordingly.
- Further steps for an AD plant would require:
  - Understanding of the proposed AD plant configuration, investigate delivery timelines and production potential.
  - Opportunities to transport generated biogas

  - The above will inform the proof of delivery that the AD CHP plant could be a long-term transition opportunity.
- Further steps for the implementation of a biomass boiler district heating scheme include:
  - Further investigation into the local biomass supply chain
  - Increase clarity on RHI subsidy future.

BHCC Actions:

- Incorporate the findings of this study in the development of the supplementary planning document for THV. Particularly the design guidance can be used for specific recommendations on the development of the site to increase viability of the heat network.
- Liaise with the developer to understand and inform the distribution of the high and low heat density areas of the masterplan to encourage heat network viability.
- Engage with the developer to explore delivery options and appetite for the local authority and developer to collaborate.

Developer Actions:

- Engage with the BHCC to explore options available to make a DH scheme viable.
- It is suggested that the developer (potentially with council support) undertake further feasibility studies to investigate alternative heat sources onsite. Including:
  - GSHP ground condition testing
  - AD delivery timelines and capacity
  - Biomass local supply chain

- When a more fixed masterplan is available further feasibility and design development is required to:

  - Test against a proposed network layout
  - Understand phasing
  - Test techno-economic modelling against phasing
  - Develop the delivery vehicle model – organisational structure
  - Soft market testing for potential operators or private sector interest
  - Begin initial considerations for legal agreements

2 Introduction

BuroHappold Engineering (BH) have been commissioned by Brighton & Hove City Council (BHCC) to undertake a high level techno – economic viability study of district heating (DH) opportunities for the Toads Hole Valley (THV) site. The site is greenfield with sustainability standards. The specification for the commission is detailed in "Schedule 1 – Service Specification, Toads Hole Valley Heat Network Service Specification , Reference number 22384".

2.1 Report aims and objectives

The aims of this report and its intended use are:

- To assess the viability of a DH scheme in the THV development area by investigating performance versus a counterfactual business as usual (BAU) solution.
- To provide high-level design guidance on the development of a DH scheme on site.
- To inform THV Supplementary Planning Document (SPD) highlighting considerations on how the DH scheme's viability can be improved. These include recommendations on density, phasing and infrastructure that will be required to deliver a DH scheme onsite.

This report is to be used for high level guidance on the development of a heat network and not intended to be used for detailed design, since the masterplan is still under consideration and has not yet been confirmed.

BHCC objectives for this study are to identify whether a DH scheme is viable for the site; to understand how DH scheme viability can be improved for the THV site; and how the development can benefit from carbon savings using low carbon technologies for heating.

The minimum carbon targets for THV as set out in City Plan Part One Policy CP8 are :

- 19% carbon reduction improvement against Part L 2013 for residential buildings,
- BREEAM excellent for major non-residential developments.

2.2 Project background

THV is an allocated greenfield development area 'DA7' within Brighton & Hove City Plan Part One. It was identified as a potential heat network cluster within "Brighton & Hove Renewable and Sustainable Energy Study" (AECOM 2012). An SPD is currently being developed by BHCC, completion and adoption is expected Autumn 2017.

The study identified 14 heat network opportunities within the Brighton & Hove area. At present three Heat Network Delivery Unit (HNDU) funded studies are in progress:

- Eastern Road,
- Hove Station,
- Shoreham Harbour.

This project has been part funded by the Department of Business, Energy and Industrial Strategy (BEIS), formerly the Department of Energy and Climate Change (DECC), and HNDU and informs an important part of the strategic intent of BHCC to secure a modern, high quality and sustainable mixed used development at THV to help meet the future needs of the city.

2.3 Policy context

Figure 2—1 outlines the hierarchy of policies for BHCC which are relevant to the reinforcement of sustainability and energy targets for new developments in the area. A detailed description of the policy context is included inAppendix B. The "policies map" indicated in the framework relates to additional policy that will potentially be developed in the future which may impact on THV.[5]

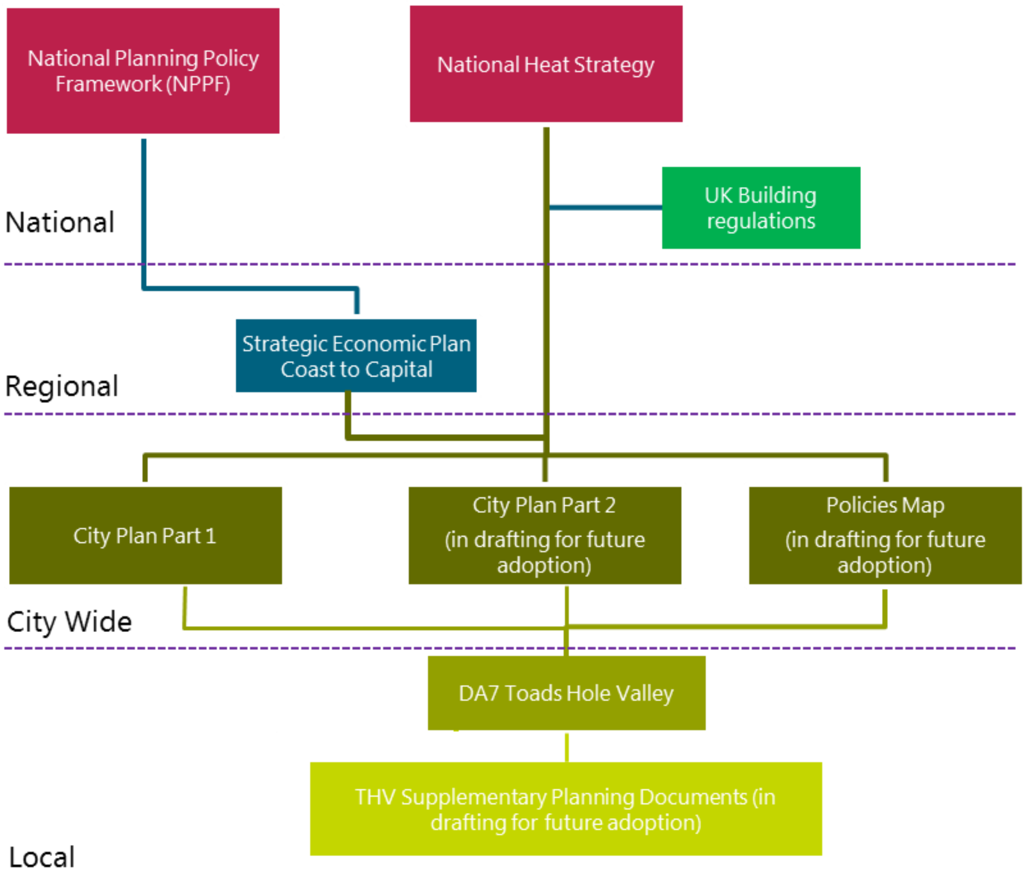

Figure 2—1 Toads Hole Valley policy framework

The key energy policies that should be taken into consideration to form the energy strategy of the development of THV site are summarised in **Table 2—1**. This table shows the various policy targets and metrics from national to local level.

[5] http://www.brighton-hove.gov.uk/content/planning/planning-policy/development-plans

Table 2—1 THV relevant energy policies

Policy		Target/metric
National	NPPF	Support the use of low carbon energy sources and the development of decentralised energy systems
		Promote developments which minimise energy consumption and greenhouse gas emissions
	National heat strategy	Reduce demand for energy in buildings. Decarbonise heating and cooling supply in buildings, with heat networks being at the core of this target Decarbonise heat in industrial processes
City Wide	City Plan Part 1	42% reduction in CO_2 emissions over a 2005 baseline by 2020 80% reduction in CO_2 emissions over a 2005 baseline by 2020 *2005 baseline is 5.7 tonnes per person.
		Support major renewable and decentralised energy infrastructure
		Reduce ecological footprint to 2.5 global hectares (gha) per person by 2020 and 1.25 gha per person by 2050.
	City Plan Part 1 – CP8	All new development to incorporate sustainable design features to avoid expansion of the city's ecological footprint, help deliver radical reductions in greenhouse gas emissions, particularly CO2 emissions, and mitigate against and adapt to climate change. All development proposals to facilitate on-site low or zero carbon technologies
		Development proposals should show how they connect, make contributions to low and zero carbon energy schemes and/or incorporate provision to enable future connection to existing or potential decentralised energy schemes.
	City Plan Part 1 – CP8	Energy performance : 19% carbon reduction improvement against Part L 2013 new build residential BREEAM excellent for major and greenfield non-residential developments BREEAM very good for non-major non-residential developments
Local	City Plan Part One Development Area Policy DA7 Toads Hole Valley	The strategy for the development of Toads Hole Valley and Court Farm is to secure a modern, high quality and sustainable mixed use development
		Local Priorities: The site is used efficiently and effectively to assist in meeting the development and infrastructure requirements of the city. The development will aim to be an exemplary standard in terms of environmental, social and economic sustainability, achieving a One Planet approach
		Strategic Allocation: Environmental sustainability will be central to the design and layout of the scheme which will be expected to meet the requirements of policy CP8. Local Development within this area will aim to incorporate infrastructure to support low and zero carbon decentralised energy and in particular heat networks subject to viability and deliverability.
		Key elements on site: A minimum of 700 residential units (residential densities within 50~75 dwelling per ha, at least 50% of dwellings should be 3-bed family sized dwellings) B1- employment space – site area 3.5 – 4.5ha Site for secondary school – 5ha Public open space – 2ha Provision of ancillary supporting uses – shops, cafes, multi-use community building Food growing space – 0.5ha Green infrastructure integrated through the site
	THV Draft SPD	The Draft Supplementary Planning Document (SPD) is under development. Once completed it will provide more detailed guidance on the required steps for the development of THV area.

2.3.1 Vision document[6]

The vision document was developed in August 2012 and summarises the developer's vision of a proposed mixed used development that would address the City Plan Policy Framework for the site. It outlines the different types of development on the site, the land use and the transport network that can be developed on site. The suggested masterplan included in the 'Vision Document' is shown in Figure 2—2. This study has adopted some of the approaches from the Vision Document as an indicator of a potential scheme that may come forward on the site.

Figure 2—2 Vision document masterplan, August 2012

[6] http://www.toadsholevalley.co.uk/vision-document.html

2.4 Site context

Toads Hole Valley is located on the northern side of Brighton & Hove, between Hangleton and Goldstone Valley residential areas, the THV Site of Natural Conservation Importance (SNCI) and the South Down National Park (SDNP), see Figure 2—3. This area is the city's largest greenfield development site which comprises of 37 hectares of land excluding the SNCI.

Figure 2—3 Map of THV site and surrounding area

The existing area surrounding THV has a relatively low heat density as shown in Figure 2—4, which indicates a low potential for extension of a new heat network. This was also confirmed when export of heat was assessed to other major developments and the West Blatchington Primary School. The results are summarised in Appendix C.

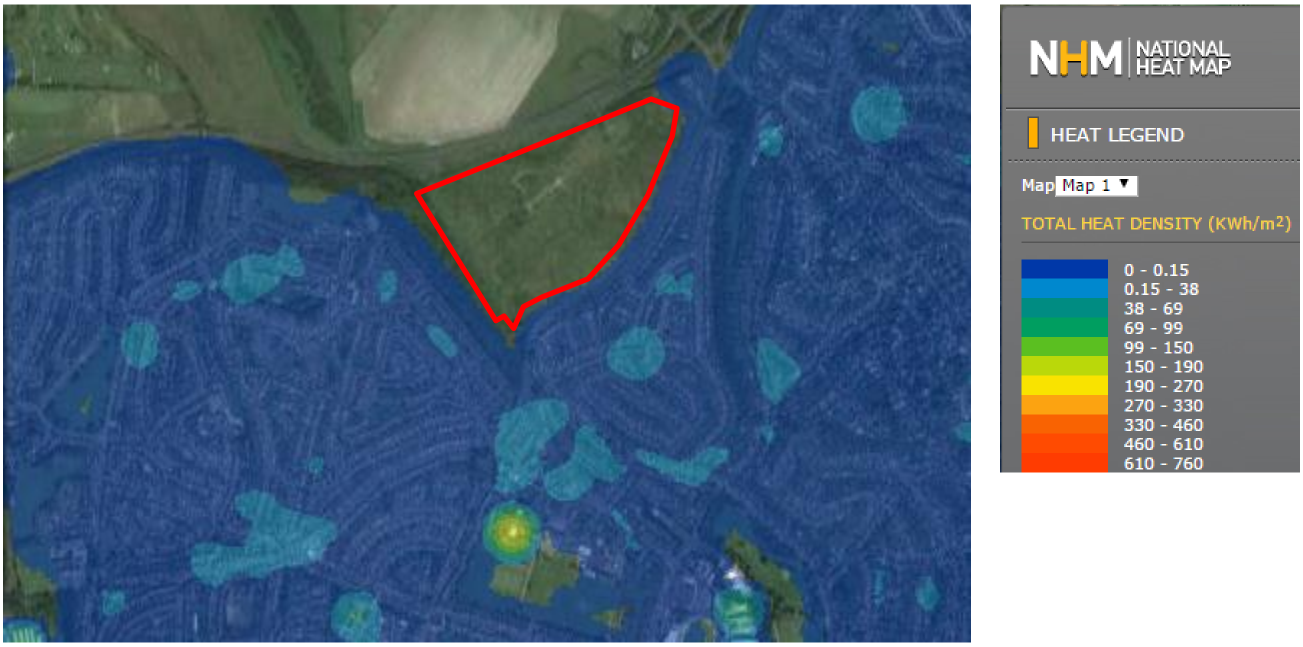

Figure 2—4 BEIS heat map of Brighton area, including legend [7]

The "Brighton & Hove Renewable and Sustainable Energy Study" states that the site topography could be considered as a potential barrier to the development of the heat network, mainly due to height variations on site. Figure 2—5 illustrates the variation in elevation across the THV site . Following a site visit by BuroHappold on the 05/05/2016 it has been concluded the topography does not present a constraint for district heating. However, the hydraulic design of DH network will need to take into account variations in level and pressure at different locations.

Figure 2—5 Site visit picture, taken on 05/05/2016 (arrows demonstrate elevation of landscape)

[7] http://tools.decc.gov.uk/nationalheatmap/

3 Justification for district heating as alternative solution

The premise for investigating DH is that it can deliver heat to the customer at a price competitive with or lower than conventional solutions and return an acceptable commercial performance for the operator, whilst offering opportunities for decarbonisation of heat. The following section investigates the commercial competitiveness of DH scheme against a boiler-only BAU case, i.e. assuming all dwellings on the site generate heat via individual gas boilers.

The BAU cost of heat is effectively the maximum retail cost which the District Heating Network (DHN) will be able to charge customers, so that they are protected against higher relative heat prices. However, the economic viability for a potential DH system is generally proven by investigating whether the marginal cost of heat is sufficiently lower than the BAU case. The DH operator needs to consider whether the ability to generate heat cheaper than the BAU reference case gives an opportunity to recover capital expenditure and ongoing operating costs. The financial performance of the scheme using this pricing will be investigated in the full techno-economic model (section 6).

The DH and BAU scheme options are described as following:

- **Option 1:** The **DH scheme** option introduces an additional utility organisation which centrally generates heat (in the energy centre) and distributes heat to buildings via a buried network of insulated pipes. The scheme replaces individual heat sources in buildings (such as gas boilers). Heat may be generated centrally from a variety of different technologies and fuel types. In this study option 1 will be referred to as the DH scheme. For the purposes of this comparison, a gas combined heat and power (CHP) led DH scheme. Gas CHP is a common technology used with DH networks and is investigated in more detail later in this report.
- **Option 2: BAU scheme** is the counterfactual energy strategy to the DH scheme which uses individual gas boilers in each dwelling for space heating and hot water. To meet the target of 19% carbon reduction improvement against Part L 2013 f the development, roof-mounted solar photovoltaic (PV) panels would be needed. The approach of gas boilers and PV is deemed to be the most likely way that the developer would meet this standards, however there are alternative solutions such as Passivhaus fabric which can further reduce heat demands through increased insulation. Electric air source heat pumps as a heat source combined with PV can be another alternative for heat source as well as the use of solar thermal for hot water.

3.1 DH system ownership model

The DH scheme that is proposed is a retail scheme. This means that the operator or the manager of the scheme is responsible for final delivery to the individual customer (i.e. each dwelling or flat, or business unit). The DHN operator responsibilities are:

- Energy centre installation, maintenance and replacement
- Heat network installation and maintenance
- HIUs installation, maintenance and replacement
- Heat metering installation and maintenance

Figure 3—1 illustrates the parts of the development which are within DHN operator's responsibilities.

The costs of each element of the system are included in the DH cost of heat.

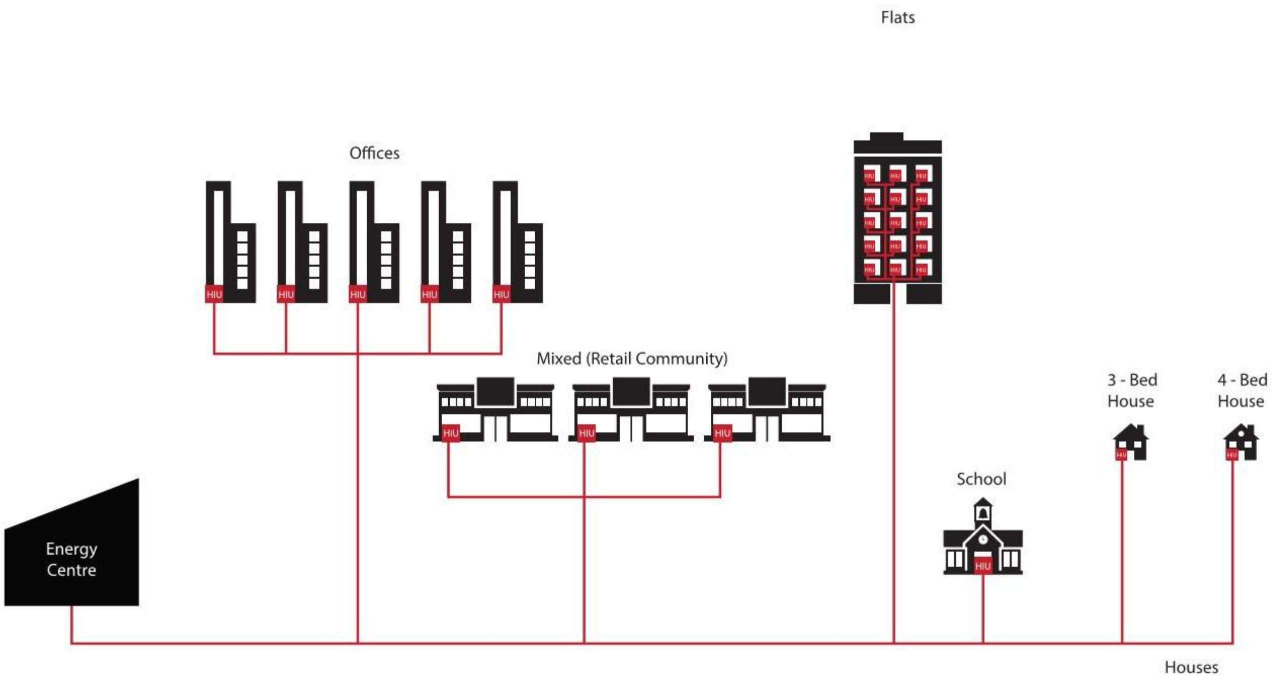

Figure 3—1 DHN responsibilities boundary

Gas boiler replacement and maintenance for the BAU is the responsibility of the homeowner and therefore included in the cost of heat calculations.

3.2 Residential Cost of Heat

Figure 3—2 illustrates the basic model of heat supply for a single dwelling for each option.

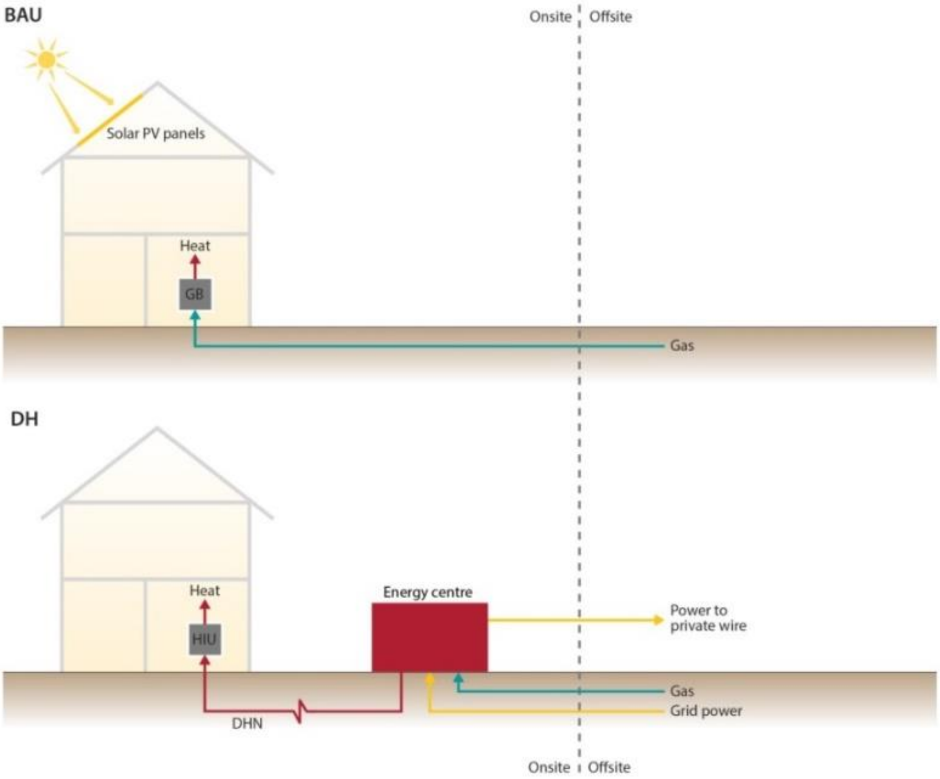

Figure 3—2 BAU vs DH option for a single town house (HIU = heat interface unit, GB = gas boiler)

As noted previously the cost of heat for the DH case must be at least equal to, or lower than the BAU case to make DH an attractive alternative for the consumer.

The BAU cost of heat includes:

- Gas fuel cost (variable price and standing charge)
- Gas boiler maintenance cost
- Gas boiler replacement cost

The DH cost of heat includes:

- Heat network maintenance costs
- HIUs maintenance and replacement costs
- Fuel costs
- Plant replacement fund
- Heat meter maintenance costs
- Staff costs
- Operation and maintenance of central plant, network and heat meters
- Annual business rates

The inputs for the BAU and DH comparison are provided in Table 3—1.

For this comparison it is assumed that the site developer sells the generated electricity from the CHP back to the grid at a grid spill price of 5.5p/kWhe.- The cost of heat for each option is based on a single 3-bed town house.

Table 3—1 BAU vs DH comparison inputs and marginal cost of heat results

BAU inputs		**Source**
Gas price	3.8/kWh	EDF 2016 prices
Gas boiler efficiency	85%	Domestic Building Services Compliance Guide (2013) minimum energy efficiency standards[8]. Assumed representative for the purposes of this high level study and through the lifecycle. New Boilers can have a nominal rating which is higher at peak efficiency and when first installed.
Gas standing charge	26.0p/day	British Gas price – mid-range of typical standing charge (15-40p/day)
Gas boiler maintenance price	£15.8/month	Scottish Power price – mid-range of typical maintenance price (£12-20/month)
Gas boiler replacement cost	£132/year	£1,500 (PlumbNation website), 11.4 year replacement period (Heat Trust Calculator)
Gas boiler life expectancy	11.4	Heat Trust Calculator
Marginal cost of heat generation	**13.7/kWh**	
DH inputs		**Source**
Gas price	2.2p/kWh	BEIS services price 2016
CHP maintenance price	1.6p/kWhe	Price for the 400kWe Edina engine. Industry maintenance costs for CHP typically provided on a kWh basis, i.e. aligned to run hours.
Energy centre gas boiler maintenance price	£10/kW	BH experience – upper limit of typical maintenance cost. Industry maintenance costs for gas boilers are generally aligned to capacity as they have fewer moving parts than CHP engine.
Grid Spill power price	5.5p/kWh	Based on active DH scheme in London and Buro Happold experience
CHP replacement cost	£33/year	CHP capital cost = £471,500, 20 years replacement period
Energy centre gas boiler replacement cost	£11/year	Boilers capital cost = £160,000, 20 years replacement period[9]
Pumping electrical energy consumption	2%	Of annual delivered heat, (CIBSE Code of Practice pg:36)
Electrical import price	10.8p/kWh	BEIS services price 2016
Network maintenance unit cost	£0.6/MWh/year	BEIS assessment of the costs, performance, and characteristics of UK heat network 2015
Staff costs for metering, billing and revenue collection	£2.5/MWh/year	BEIS assessment of the costs, performance, and characteristics of UK heat network 2015
Business rate	£6.0/MWh/year	BEIS assessment of the costs, performance, and characteristics of UK heat network 2015
HIUs maintenance cost	£9/MWh	BEIS assessment of the costs, performance, and characteristics of UK heat network 2015
HIUs replacement cost	£130/year	HIUs capital cost for residential=£2,600, 20 years replacement period
Heat meter maintenance cost	3.4 £/MWh/year	BEIS assessment of the costs, performance, and characteristics of UK heat network 2015
Marginal cost of heat generation	**10.8 p/kWh**	

[8] Although new boiler systems are expected to reach efficiencies of 90%, this efficiency can be achieved when the boiler system operated under full load and therefore a 85% efficiency has been assumed for allowing underutilisation of the system.
[9] https://www.plumbnation.co.uk/site/natural-gas-combination-boilers/?page=1&sort=lowest

Based on these inputs it is shown that the cost of heat for DH is 10.8 p/kWh per 3-bed town house, as compared with the BAU case of 13.7/kWh. To validate the cost of heat for the BAU based on BH approach, the Heat Trust Calculator was used. For a similar size and heat demand property in the area of Brighton, the cost of heat using Heat Trust Calculator is estimated at 13.6 p/kWh[10].

The BAU and DH cost of heat indicate a small marginal profit that can be achieved through the DHN operation, since considering consumer protection the heat sales price could not exceed the 13.6p/kWh. Should a DHN be installed on the site the network operator could therefore charge each consumer up to 11.7p/kWh, i.e. thereby generating a profit for each unit of heat delivered and an attractive cost saving to the consumer. The heat price of 11.7p/kWh for the residential heat demand is 15% lower than BAU cost of heat for a town house (13.7p/kWh).

This demonstrates that DH is a viable option on a cost of heat basis for the THV development albeit with a marginal profit due to ongoing operating costs.

[10]http://heattrust.org/index.php/test-the-comparator
http://heattrust.org/images/docs/HCC_Further_information_and_assumptions_Final.pdf

3.3 Non-residential cost of heat

The same methodology was followed for estimating the non-residential cost of heat for the DHN and the BAU solution. The non-residential unit is assumed to be a business unit of 5,000m². The inputs for the BAU and DH comparison are provided in **Table 3—2**.

Table 3—2 BAU vs DH comparison inputs and marginal cost of heat results – non-residential

BAU inputs		Source
Gas price	3.8/kWh	EDF 2016 prices
Gas boiler efficiency	85%	Domestic Building Services Compliance Guide (2013) minimum energy efficiency standards[11]
Gas standing charge	91.0p/day	British Gas price – mid-range of typical standing charge for businesses
Gas boiler maintenance price	£10/kW	BH experience – upper limit of typical maintenance cost
Gas boiler replacement cost	£1,120/year	£80£/kW (Spons 2015), 20 year replacement period
Marginal cost of heat generation	**11p/kWh**	
DH inputs		**Source**
Gas price	2.2p/kWh	BEIS services price 2016
CHP maintenance price	1.6p/kWhe	Price for the 400kWe engine from Edina range
Energy centre gas boiler maintenance price	£10/kW	BH experience – upper limit of typical maintenance cost
Grid Spill power price	5.5p/kWh	Based on active DH scheme in London and Buro Happold experience
CHP replacement cost	£33/year	CHP capital cost = £471,500, 20 years replacement period
Energy centre gas boiler replacement cost	£11/year	Boilers capital cost = £160,000, 20 years replacement period[12]
Pumping electrical energy consumption	2%	Of annual delivered heat,(CIBSE Code of Practice pg:36)
Electrical import price	10.8p/kWh	BEIS services price 2016
Network maintenance unit cost	£0.6/MWh/year	BEIS assessment of the costs, performance, and characteristics of UK heat network 2015
Staff costs for metering, billing and revenue collection	£2.5/MWh/year	BEIS assessment of the costs, performance, and characteristics of UK heat network 2015
Business rate	£6.0/MWh/year	BEIS assessment of the costs, performance, and characteristics of UK heat network 2015
HIUs maintenance cost	9 £/MWh	BEIS assessment of the costs, performance, and characteristics of UK heat network 2015
HIUs replacement cost	1000 £/year	HIUs capital cost for residential=£20,000, 20 years replacement period
Heat meter maintenance cost	3.4 £/MWh/year	BEIS assessment of the costs, performance, and characteristics of UK heat network 2015
Marginal cost of heat generation	**8.7 p/kWh**	

[11] Although new boiler systems are expected to reach efficiencies of 90%, this efficiency can be achieved when the boiler system operated under full load and therefore a 85% efficiency has been assumed for allowing underutilisation of the system.
[12] https://www.plumbnation.co.uk/site/natural-gas-combination-boilers/?page=1&sort=lowest

Based on these inputs it is shown that the cost of heat for DH is 8.7 p/kWh for a non-residential, as compared with the BAU case of 11p/kWh.

The BAU and DH cost of heat indicate a small marginal profit that can be achieved through the DHN operation. The heat sales price should not exceed the 11p/kWh to ensure competitiveness with the BAU case. The DHN operator could potentially charge each consumer up to ~9.3p/kWh, thereby generating a profit for each unit of heat delivered and still provide an attractive cost saving to the consumer. The heat price of 9.3p/kWh for the non-residential heat demand is 15% lower than the BAU cost of heat for a non-residential unit.

Similarly to the residential development, DH is a viable option on a cost of heat basis for the THV non-residential developments but with marginal profit.

4 Methodology

The methodology applied within this study has been split into the stages given in Figure 4—1. The first stage of the project starts with confirming the masterplan scenarios for the analysis. The heat demand assessment and heat profiling is then completed in order to understand the energy requirements for the different scenarios. The heat supply assessment then informs the study on the applicable low carbon technologies and scale to be considered in the techno-economic modelling. The final step in the process is the provision of design guidance and planning recommendations for inclusion in the supplementary planning guidance (SPD).

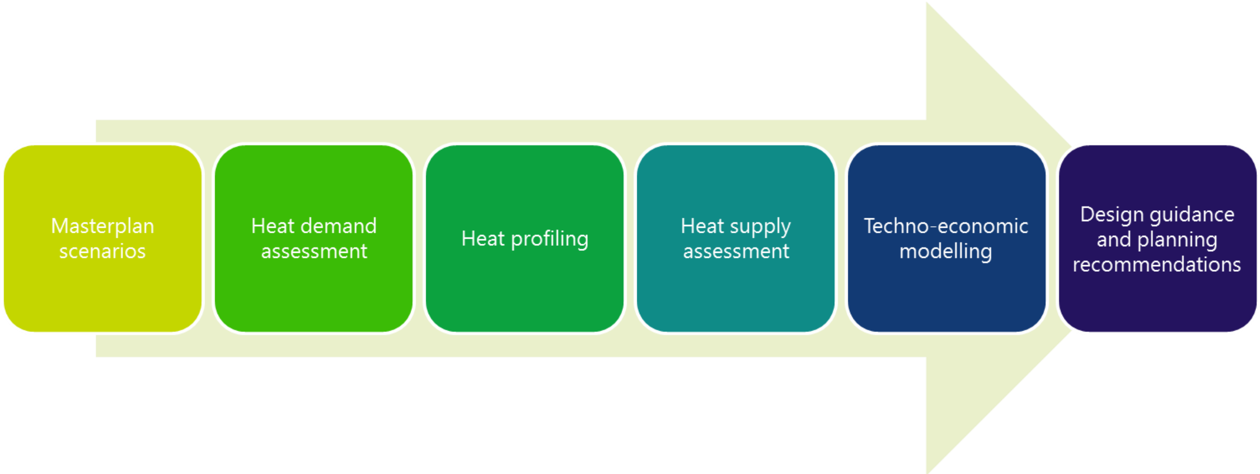

Figure 4—1 Project methodology

5 Masterplan scenario analysis

5.1 Masterplan scenarios

A number of masterplan options could be considered for the THV development, affecting both the location and combination of building typologies across the site and the number of residential units. The lack of a finalised masterplan specifying allocated uses on site in conjunction with the number of residential units per housing typology, has increased the complexity of developing suitable DH scheme scenarios.

Following consultation with BHCC, it has been agreed that this heat network study would be based upon four scenarios which reflect possible development density scenarios of the completed masterplan to test long term commercial viability of a DH scheme. The proposed masterplan scenarios have been developed based on delivery options related to DA7 policy and the developers 'vision document' masterplan.

The scenarios that have been assessed are as following:

Scenario 1: Low density scenario with high number of detached and terraced houses

Scenario 2: High density scenario with higher number of flats and terraced housing, increasing residential density by 20%.

Scenario 3: High density scenario with 20% increase in residential units. In this scenario the total number of dwellings increases by 20% over scenarios 1 and 2. Proportion of houses to flats are taken as per scenario 2.

Scenario 4: High density scenario, excluding houses: This scenario is the same as scenario 2 but it does not include the terraced houses.

Due to unknowns regarding how the development may be phased it is too early to consider how the DH scheme may be delivered in stages and what impact this may have on the commercial model. Some form of commitment of phasing from the housing developer will likely be needed to ensure a third party DH operator can adequately project costs and investment. In further studies the impact of the phasing will need to be investigated.

Although phasing is not used for the modelling of the study, phasing recommendations are included within the report and the Design Guidance .

The visual layout/concept, as shown in Figure 5—1, is utilised to represent the scenarios at a high-level.

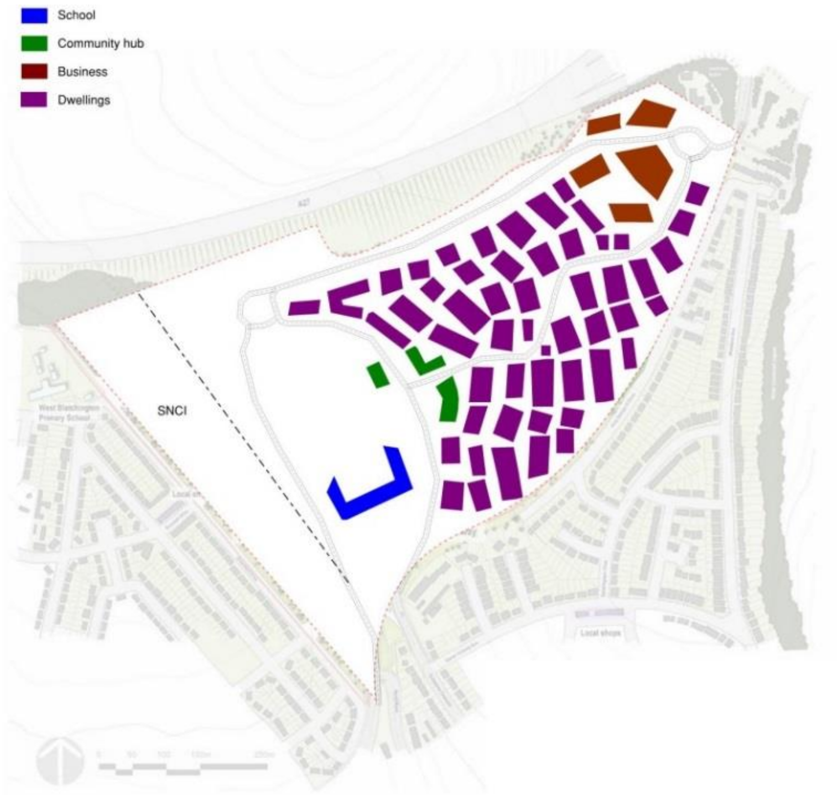

Figure 5—1 High level masterplan based on the vision document – scenario 1

It should be noted that scenarios 1 to 4 are masterplan scenarios and do not refer to energy supply scenarios. In this study the term scenario refers only to the masterplan scenarios and should not be confused with the heat supply options that are analysed in this section.

The assumed split of building typology for each scenario in the heat demand assessment and the techno-economic modelling area is summarised in Table 5—1. Detailed descriptions of each scenario are included Appendix D.

Table 5—1 Masterplan scenarios

Typology	Scenario 1	Scenario 2	Scenario 3	Scenario 4
	Low density- Meets DA7 allocation. As per Vision masterplan DHN to all buildings.	**High density-** Meets DA7 allocation. As per Vision Document masterplan. DHN to all buildings.	**High density –** Meets DA7 allocation and increases number of dwellings by 20%.	As Scenario 2. DHN does not extend to individual houses
Houses (units)	386	280	336	-
Flats (units)	314	420	484	420
Mixed use buildings[13] (buildings, including flats and community facilities)	-	4	4	4
Non-residential uses (buildings, including 25,000m^2 of offices)	5	5	5	5
Community hub (buildings-shops, cafes and community facilities)	3	-	-	-
School (buildings)	1	1	1	1
Housing Density (Dwelling per Hectare)	**53**	**65**	**65**	**84**

An application has been submitted for the Court Farm Site: BH2015/04184. At time of report issue (October 2016), the application is still under consideration. Planning application BH2014/04184 has not been considered in the analysis for this report. The allocation of Court Farm site is part of the overall DA7 policy, and this study assesses opportunities for DH on the basis of the whole development area, including Court Farm (Figure 2—3).

[13] Mixed buildings are buildings which include non-residential space (shops, offices, cafes, community facilities) in the ground floor and flats are located in the upper floors as per Table 5—3 to Table 5—5.

5.2 Energy demand assessment

The energy demand assessment was conducted for each development scenario using the benchmarking process given in Figure 5—3 below. A detailed list of the benchmarks is included in the Appendix E.

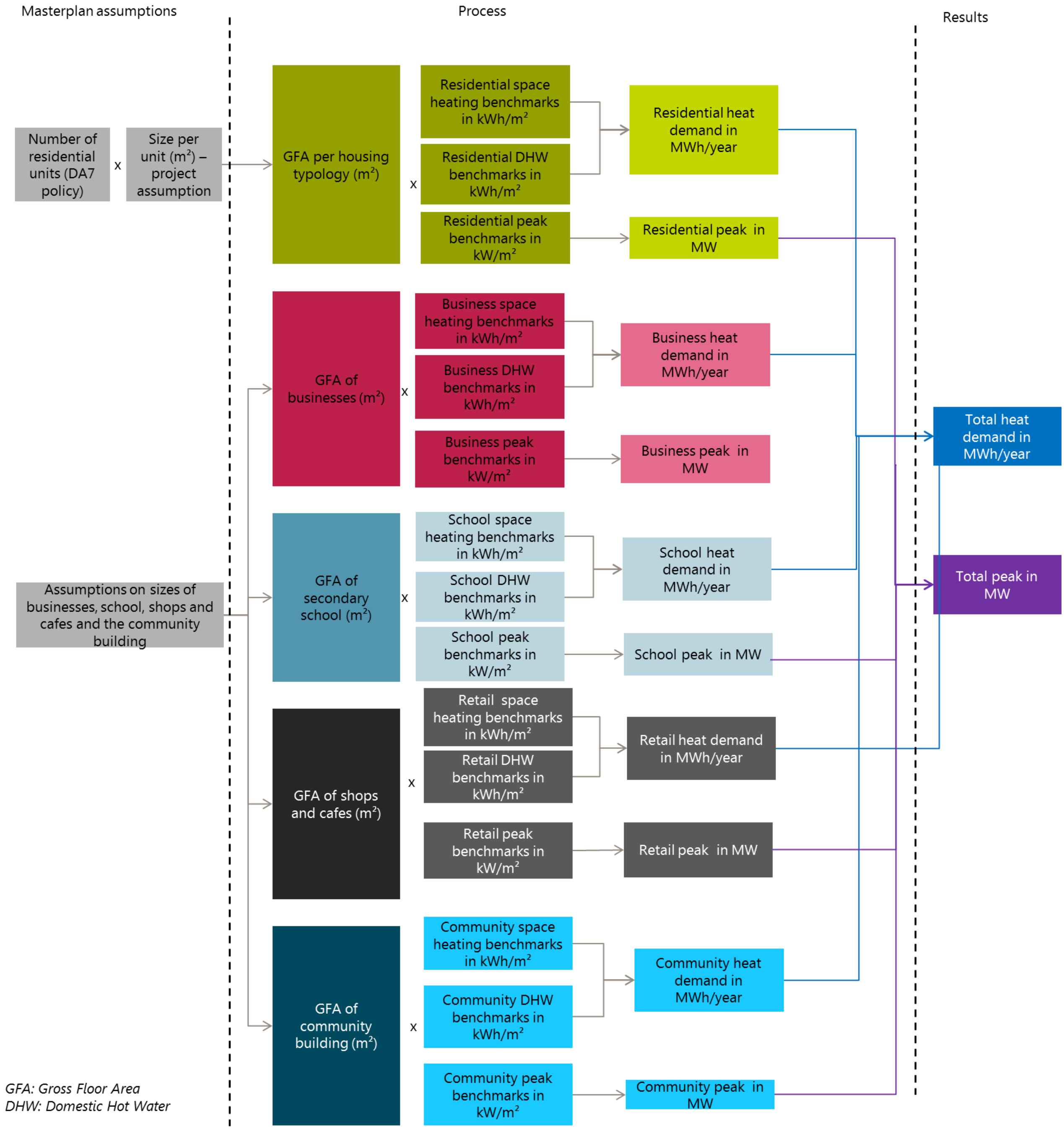

Figure 5—2 Heat demand assessment process

The results of the demand assessment are summarised in Table 5—2 to Table 5—5. Details on demand benchmarks are given in Appendix E. The annual heat and electricity benchmarks that have been used have been developed in house by BuroHappold using SAP modelling.

The provision of cooling in residential developments in the UK climate is not generally required and sustainable design principles of passive design and solar control are generally adequate to avoid active cooling and control overheating. Therefore, there is no active cooling allowed for in residential units. Where cooling is required for the commercial and retail spaces it is expected that this will be provided through decentralised local units. The projected quantity of cooling (peak and annual) is not deemed high enough to justify a district cooling network.

Table 5—2 Load schedule - Scenario 1

Building	Units or m²	Space heating (MWh/year)	DHW (MWh/year)	Total heat demand (MWh/year)	Total peak (kW)	Regulated electricity (MWh)
4-bed houses	36 no.	89	59	148	110	18
3-bed houses	350 no.	807	778	1585	1,207	218
2-bed flats	174 no.	276	384	660	585	77
1-bed flats (total)	140 no.	167	195	362	311	40
1- bed mid floor apartments	70 no.	70	98	168	149	20
1-bed ground floor apartments	35 no.	35	49	84	74	10
1-bed top floor apartments	35 no.	61	49	110	88	10
Employment site	25,000m²	280	45	325	1,400	1,225
Secondary School	10,000m²	322	63	385	696	208
Shops and Cafes	2,500m²	25	33	58	200	123
Community facilities	2,500m²	68	10	78	174	56
Total		**2,034**	**1,567**	**3,601**	**4,683**	**1,965**

Table 5—3 Load schedule - Scenario 2

Building	Units or m²	Space heating (MWh/year)	DHW (MWh/year)	Total heat demand (MWh/year)	Total peak (kW)	Regulated electricity (MWh)
4-bed houses	36 no.	101	97	198	151	27
3-bed houses	244 no.	562	543	1,105	841	152
3-bed flats	98 no.	256	295	551	474	59
3- bed mid floor apartments	53 no.	115	160	275	244	32
3-bed ground floor apartments	18 no.	39	54	93	83	11
3-bed top floor apartments	27 no.	102	81	183	147	16
2-bed flats	174 no.	327	384	710	612	76
2- bed mid floor apartments	87 no.	138	192	330	293	38
2-bed ground floor apartments	44 no.	70	97	167	148	19
2-bed top floor apartments	43 no.	119	95	213	172	19
1-bed flats	124 no.	175	201	375	322	40
1- bed mid floor apartments	70 no.	82	113	195	173	23
1-bed ground floor apartments	19 no.	22	31	53	47	6
1-bed top floor apartments	35 no.	71	57	127	103	11
Flats in mixed buildings	24 no.	49	50	99	83	10
1- bed mid floor apartments	16 no.	19	26	45	40	5
3-bed top floor apartments	8 no.	30	24	54	44	5
Employment site	25,000m²	280	45	325	1,400	1,225
Secondary School	10,000m²	322	63	385	696	208
Shops and Cafes	2,500m²	25	33	58	200	123
Community facilities	2,500m²	68	10	78	174	56
Total		**2,164**	**1,720**	**3,885**	**4,954**	**1,976**

Table 5—4 Load schedule - Scenario 3

Type of load	Units or m²	Space heating (MWh/year)	DHW (MWh/year)	Total heat demand (MWh/year)	Total peak (kW)	Regulated electricity (MWh)
4-bed houses	42 no.	118	114	231	176	32
3-bed houses	294 no.	678	654	1,331	1,014	183
3-bed flats	118 no.	307	356	663	570	71
3- bed mid floor apartments	63 no.	137	190	327	290	38
3-bed ground floor apartments	23 no.	50	69	119	106	14
3-bed top floor apartments	32 no.	121	96	217	175	19
2-bed flats	210 no.	395	463	858	740	93
2- bed mid floor apartments	105 no.	167	231	398	353	47
2-bed ground floor apartments	52 no.	83	115	197	175	23
2-bed top floor apartments	53 no.	146	117	263	212	23
1-bed flats	152 no.	213	246	459	395	49
1- bed mid floor apartments	84 no.	98	136	234	207	27
1-bed ground floor apartments	26 no.	30	42	72	64	8
1-bed top floor apartments	42 no.	85	68	153	123	14
Flats in mixed buildings	24 no.	49	50	99	83	10
1- bed mid floor apartments	16 no.	19	26	45	40	5
3-bed top floor apartments	8 no.	30	24	54	44	5
Employment site	25,000m²	280	45	325	1,400	1,225
Secondary School	10,000m²	322	63	385	696	208
Shops and Cafes	2,500m²	25	33	58	200	123
Community facilities	2,500m²	68	10	78	174	56
Total		**2,455**	**2,033**	**4,488**	**5,447**	**2,050**

Table 5—5 Load schedule - Scenario 4

Building	Units or m²	Space heating (MWh/year)	DHW (MWh/year)	Total heat demand (MWh/year)	Total peak (kW)	Regulated electricity (MWh)
3-bed flats	98 no.	256	295	551	474	59
3- bed mid floor apartments	53 no.	115	160	275	244	32
3-bed ground floor apartments	18 no.	39	54	93	83	11
3-bed top floor apartments	27 no.	102	81	183	147	16
2-bed flats	174 no.	327	384	711	613	76
2- bed mid floor apartments	87 no.	138	192	330	293	38
2-bed ground floor apartments	44 no.	70	97	167	148	19
2-bed top floor apartments	43 no.	119	95	214	172	19
1-bed flats	124 no.	175	201	376	323	40
1- bed mid floor apartments	70 no.	82	113	195	173	23
1-bed ground floor apartments	19 no.	22	31	53	47	6
1-bed top floor apartments	35 no.	71	57	128	103	11
Flats in mixed buildings	24 no.	49	50	99	84	10
1- bed mid floor apartments	16 no.	19	26	45	40	5
3-bed top floor apartments	8 no.	30	24	54	44	5
Employment site	25,000m²	280	45	325	1,400	1,225
Secondary School	10,000m²	322	63	385	696	208
Shops and Cafes	2,500m²	25	33	58	200	123
Community facilities	2,500m²	68	10	78	174	56
Total		**1,502**	**1,081**	**2,583**	**3.964**	**1,797**

Summary graphs of the annual heat consumption and peak heat are shown in Figure 5—3 and Figure 5—4.

Figure 5—3 shows the heat consumption in each scenario split in space heating and hot water. Scenario 3 has the highest heat demand of all the scenarios due to 20% increase in the number of dwellings. Scenario 2 has a higher heat demand than scenario 1 due to the mix of residential typologies. According to masterplan assumptions, 3-bed flats are slightly larger than 3-bed houses. In addition the top floor 3-bed flats have higher space heating demand per meter square than the 3-bed houses, based on the applied benchmarks.

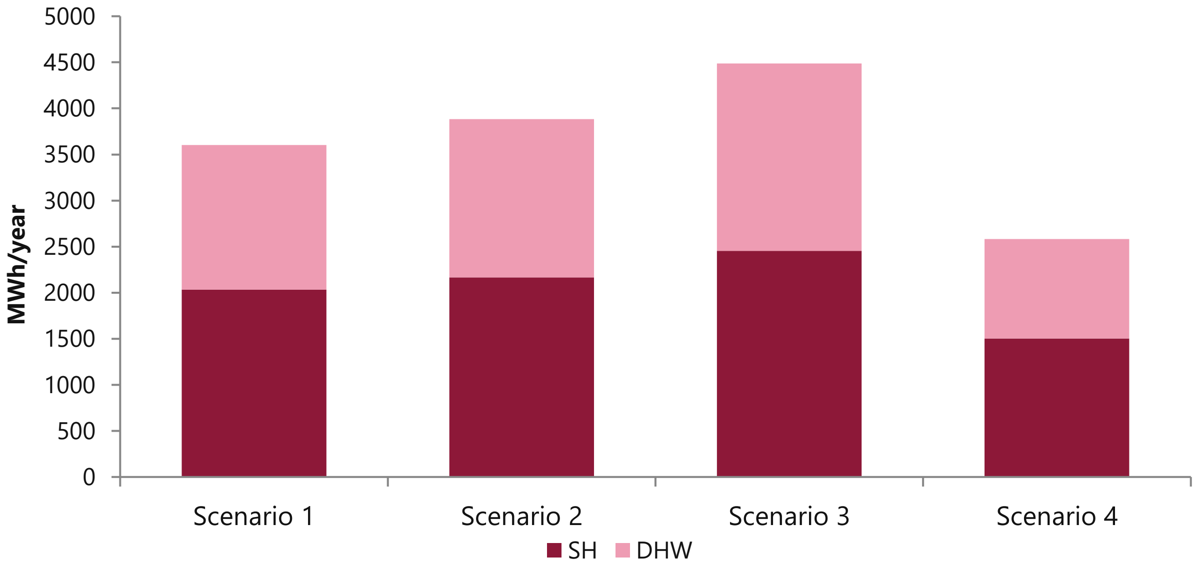

Figure 5—3 Annual heat demand per scenario (SH: space heating , DHW: domestic hot water)

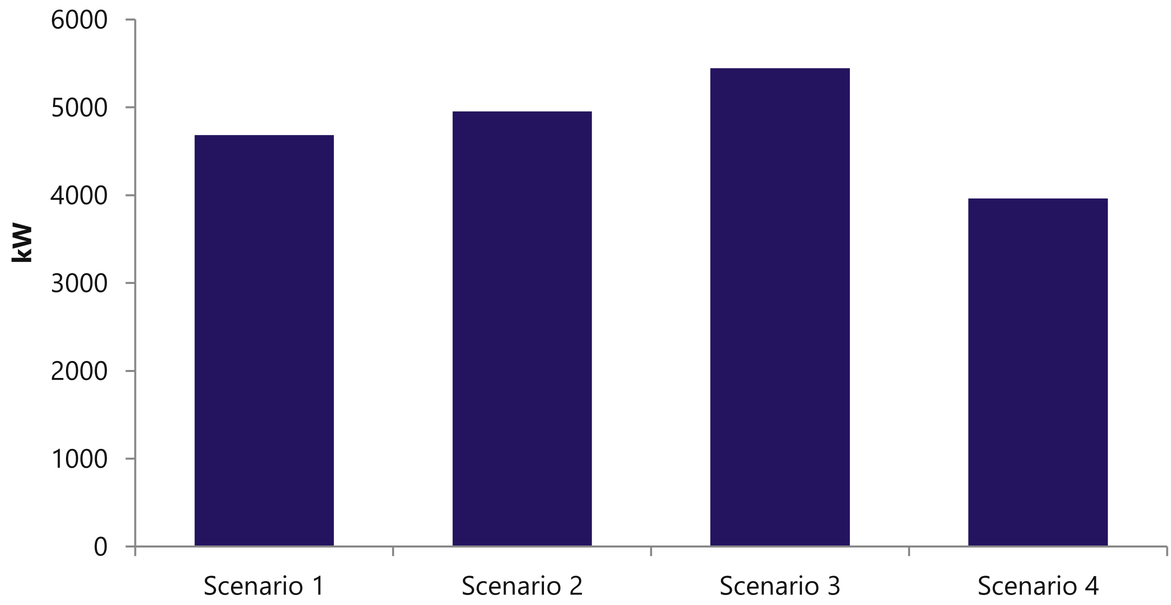

Figure 5—4 Peak heat per scenario

5.3 Heat profiling

A summary of the annual and peak heat demands of the scenarios considered is given in Table 5—6. Heat demand profiles for each load type (i.e. building typology) were created and used to inform the annual load duration curves for scenarios 1-4, as illustrated in Figure 5—5.

An additional 7.5% demand has been added to the heat loads in order to allow for distribution losses across the proposed heat network as per CIBSE Code of Practice on heat networks..

Table 5—6 Scenarios loads for techno-economic assessment

Scenario	Resi heat demand (MWh/year)	Non-resi heat demand (MWh/year)	Network losses (MWh/year)	Total heat demand (MWh/year)	Resi peak (kW)	Non resi peak (kW)
Scenario 1	2,755	846	288	3,889	2,213	2,470
Scenario 2	3,039	846	311	4,195	2,484	2,470
Scenario 3	3,642	846	359	4,847	2,977	2,470
Scenario 4	1,735	846	207	2,788	1,492	2,470

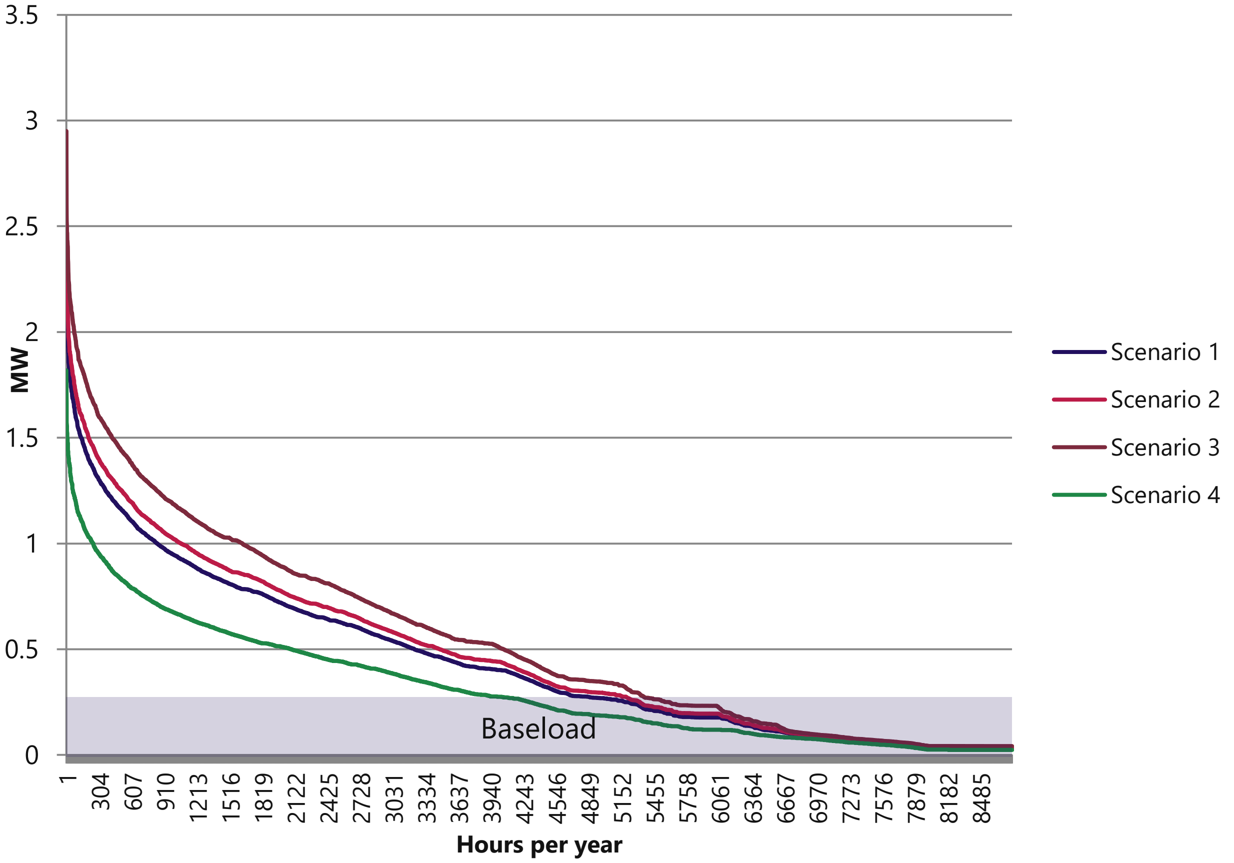

Figure 5—5 Heat load duration curve (example baseload shown for scenario 2)

Baseload

The load duration curve is used to inform the plant sizing and the energy modelling. Good practice suggests that the CHP plant would be sized to meet the baseload (equivalent to 5000~6000 run hours through the year). The baseload for scenarios 1 to 3 is 300kW to 400kW. This is used to inform the heat supply assessment in section 5.4. The baseload for scenario 4 is approximately 180kW.

5.4 Heat supply assessment

This section presents a review of all the low carbon heat technologies which could be considered for the THV heat network. An initial assessment considered eight heat sources that are typically used for DH schemes (**Table 5—7**).

Table 5—7 Sources of heat for DH scheme

Heat Source	Description	Eligible for RHI?	Considered for THV?	
Combined Heat and Power (CHP)	Gas engine generates low carbon heat and electrical power giving an increased combined efficiency and generating revenue through the sale of both heat and power.	No	✓	Yes – CHP is a mature technology and is a well understood heat network supply solution. It is considered a transition technology to kick-start a network which then can be replaced by another low carbon technology once other technologies mature and the gas price increases.
Biomass boiler	Burns biomass often in the form of woodchips or pellets to create heat.	Yes	✓	Yes– Biomass solutions can be discouraged by some local authorities in dense urban areas due to their potential impact on air quality and increased vehicle movements for fuel delivery. These constraints may be less problematic at this low density urban fringe greenfield site which is also close to a good transport junction.
Air Source Heat Pumps (ASHP)	Extracts heat from the air through an electrically driven compression cycle	Yes	X	No – Could be considered locally for individual homes in the future as the technology at scale becomes more competitive in price and carbon performance as the grid power is decarbonised and system temperatures on the network are reduced. However, it may be possible to install ASHP in some more isolated buildings.
Ground Source Heat Pumps (GSHP)	Extracts heat from the ground through an electrically driven compression cycle	Yes	✓	Yes –Ground conditions and existing known 85m depth borehole at the south-west side of the site, which could be used for heat extraction – further ground proving is required
Water Source Heat Pumps (WSHP)	Extracts heat from water through an electrically driven compression cycle	No	X	No – No water source available close to the THV site.
Deep geothermal	Extracts heat from the ground from deep drilled wells by pumping liquid into the ground to recover the heat.	Yes	X	No – Not suitable due to low geothermal heat flux in this area and high costs for the scale of the development.[14]
Anaerobic Digestion Plant Combined Heat and Power (AD CHP)	Heat taken from AD plant and injected into the network	Yes	✓	Yes -to be considered for connection to potential AD plant at Hangleton Bottom.
Solar thermal	Panels and collectors capture energy from the sun to generate heat.	Yes	X	No – Not considered appropriate, since it is usually used for domestic hot water only and generates intermittent heat. Could be considered locally for individual properties for hot water supply.

[14] Deep Geothermal Review Study – Department of Energy & Climate Change, October 2013

Four of the eight sources were shortlisted as the most suitable for the THV development and are analysed in detail in sections 5.4.1to 5.4.4, according to the following criteria:

- Applicability to the site,
- Carbon dioxide emissions,
- UK market maturity,
- Levelised costs.

The following map shown in **Figure 5—6** indicates the main primary heat supply source points that could potentially be used for the THV heat network, including the existing gas network, potential AD plant site and existing groundwater borehole for GSHP.

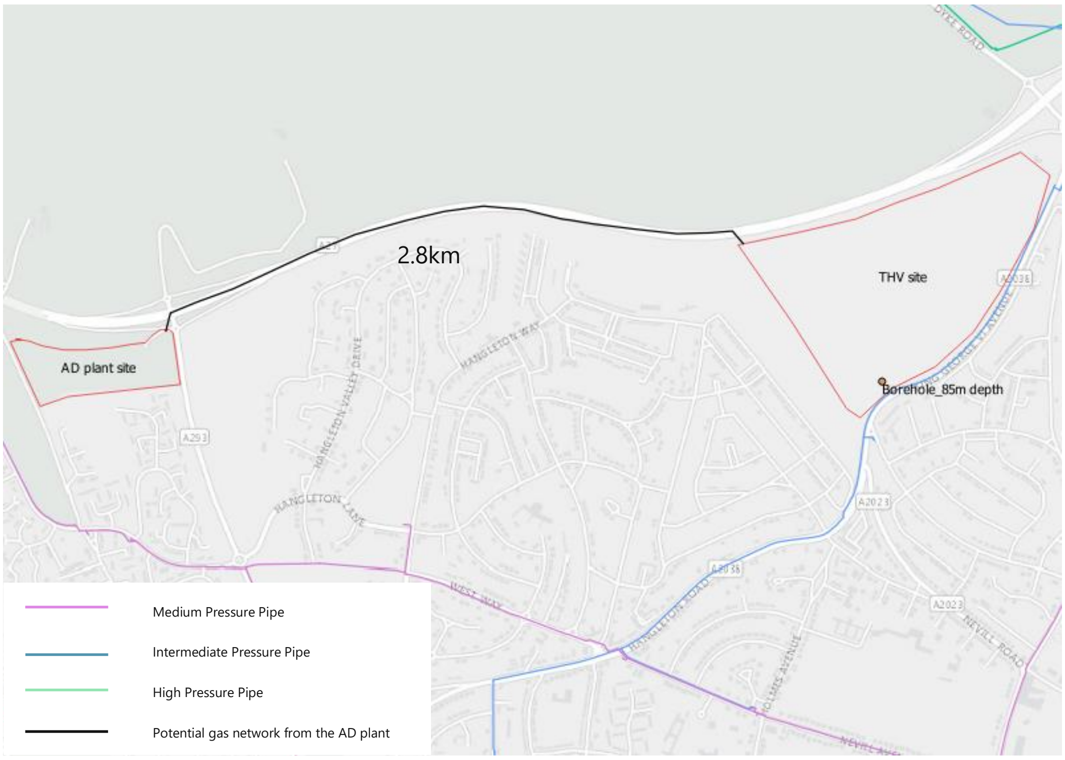

Figure 5—6 DH supply sources options map

5.4.1 Description and applicability to the site

Gas CHP

Gas CHP technology refers to the simultaneous production of electricity and heat, through heat recovery from electricity generation in the energy centre. Heat is then transferred through the distribution network to the end consumers and electricity is fed back to the grid or to electricity customers. **Figure 5—7** and **Figure 5—8** show a simplified system schematic and installation respectively.

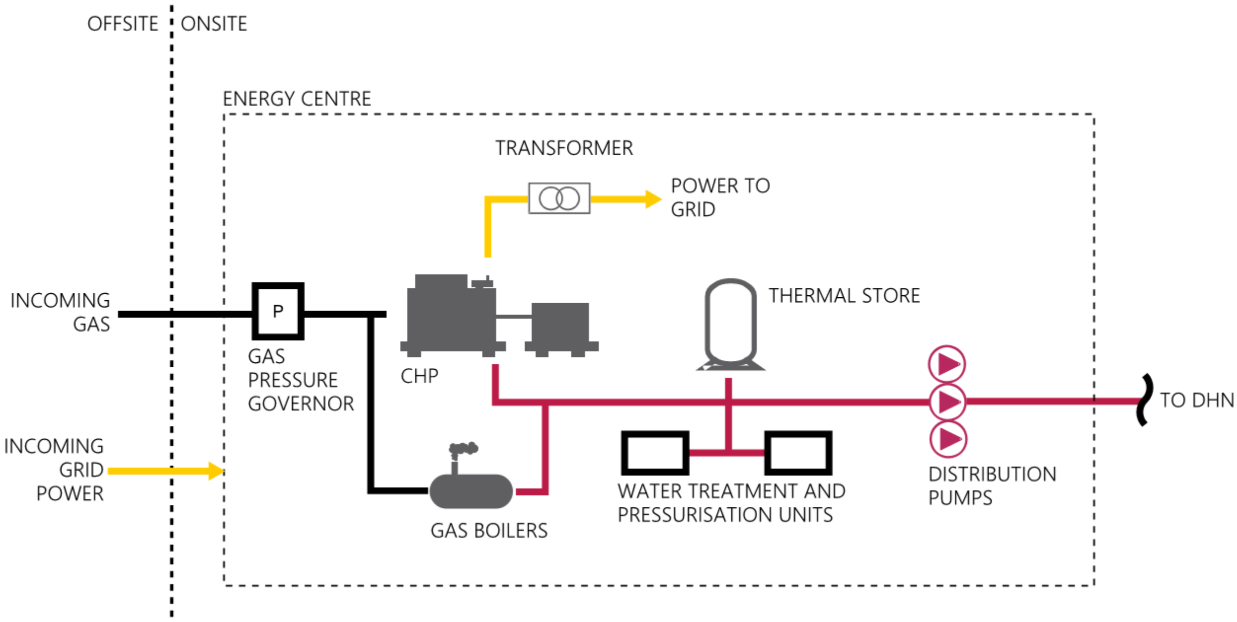

Figure 5—7 Gas CHP system

Figure 5—8 Typical gas CHP engine at the Olympic Park energy centre

Typically CHP engines are ~40% thermally and electrically efficient depending on size, giving overall efficiencies of upwards of 80%. Although this overall efficiency is lower than typical gas boilers, the higher carbon savings arise from the generation of electricity, which offsets consumption of grid electricity. Grid electricity has a higher average carbon emission factor as compared with gas, meaning any offset electricity imports saves carbon.

CHP engines achieve the highest efficiency when operating at full load, i.e. at constant maximum output. For this reason they are typically used to serve the base load of a heat network, in order to allow longer hours operating at this maximum output (see section 5.3).

The main constraint for implementing gas CHP technology in any area is the availability of connection to the existing gas and electricity grid. The THV area constitutes a greenfield site, and new gas and electrical networks will be installed. However there are gas networks in the surrounding areas, which can be extended to the THV site. The high pressure (HP), intermediate pressure (IP) and medium pressure (MP) gas mains are shown in Figure 5—6. Similarly the electricity network of the surrounding area can be extended to the site for power supply to the energy centre.

Ground Source Heat Pumps (GSHP)

GSHP technology relies on the fact that at depths below 6m, ground temperatures are stable throughout the year. The ground can act as both a heat sink and supply of heat. Heat can be extracted from open systems (using aquifers) or closed loop systems (using boreholes).

Open loop

In open-loop GSHP systems (**Figure 5—9**) water is extracted from the ground, passed through a heat exchanger and returned to a separate borehole. An image of a typical borehole is provided in **Figure 5—10**. The heat extracted is available through a water to water heat exchanger. An open-loop GSHP system requires a suitable below ground aquifer for groundwater extraction and re-injection.

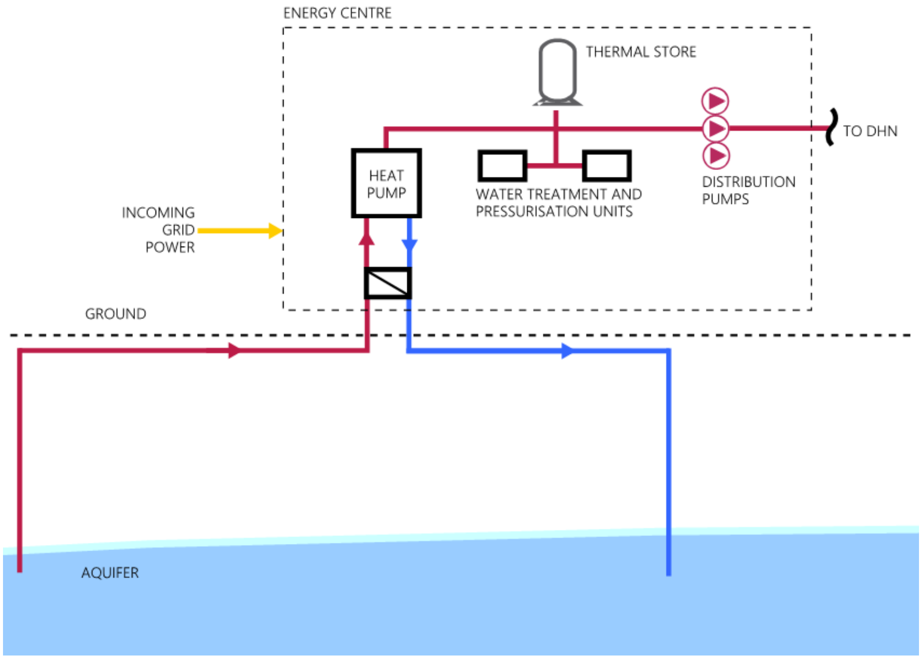

Figure 5—9 GSHP open-loop system

Figure 5—10 Typical open loop heat pump borehole

To assess the potential for an open-loop system the British Geological Survey (BGS) open-loop GSHP screening tool has been used which shows that in the area of THV there are good aquifer resources for open loop systems (Figure 5—11). It is also known that a borehole of 85m depth exists at the south-west side of the site which could be used for heat extraction (Figure 5—6). Although there is uncertainty around the borehole or surrounding conditions this is likely to be from previous industrial activity on site. It is unknown at what depth the aquifer can be found and the sustainable yield (l/s) and groundwater temperature. The BGS tool on UK boreholes does not include any information on the localised typical flow rate of the aquifer in this borehole[15]. An additional borehole would be needed for groundwater rejection.

[15] http://mapapps.bgs.ac.uk/geologyofbritain/home.html

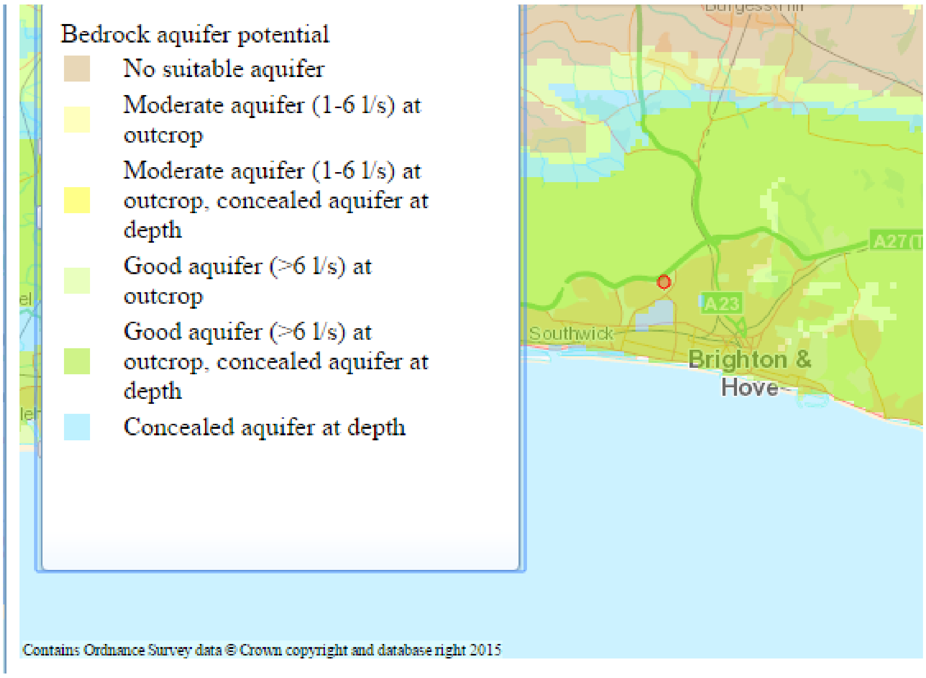

Figure 5—11 Bedrock aquifer for open-loop GSHP potential >100kWth[16]

To estimate the amount of heat that can be provided by an open-loop GSHP system for THV the following assumptions have been applied:

- flow rate: 10l/s,
- ground temperature at 12.5°C (average UK ground temperature),
- COP heat pump: 4.5.

A borehole of this specification can provide approximately 250kW of heat. This heat can then be fed into the heat pump and produce approximately 290kW of heat (with additional HP compressor heat). This amount of heat would be sufficient to supply approximately 70% of the baseload from scenarios 1 and 2.[17] For scenario 4, the extracted amount of heat would be sufficient to supply approximately all the baseload.

GSHP systems generating heat currently qualify for the RHI which could improve the economic viability once the technical potential and system configuration is developed further.

In addition, this open loop system would be more efficient combined with cooling of commercial buildings since in the summer it could operate in reverse mode, re-injecting heat to the hot borehole and extracting heat from the cold borehole.

In summary, although the assessment shows that there is potential for an open-loop system, there is also uncertainty without further steps. These would require:

- Borehole condition survey and testing to accurately estimate the heat supply potential;
- Environment Agency (EA) consultation to hold a licence for groundwater extraction and rejection;
- Pump test to accurately estimate the heat supply potential;
- Viability of low temperature heating systems within the buildings and for network.

[16] http://mapapps2.bgs.ac.uk/gshpnational/home.html
[17] THV schemes baseload is 400kW in scenarios 1 and 2 and 530kW in scenario3.

Closed loop

In closed-loop GSHP systems, a ground heat exchanger is installed which consists of a sealed loop of pipes, buried either horizontally or vertically in the ground. A glycol liquid is circulated through the ground loop and energy is transferred to and from the heat pump refrigerant circuit (**Figure 5—12**). Closed-loop systems are more widely applicable than open loop systems since they do not rely on an aquifer and their installation does not required EA Permission.

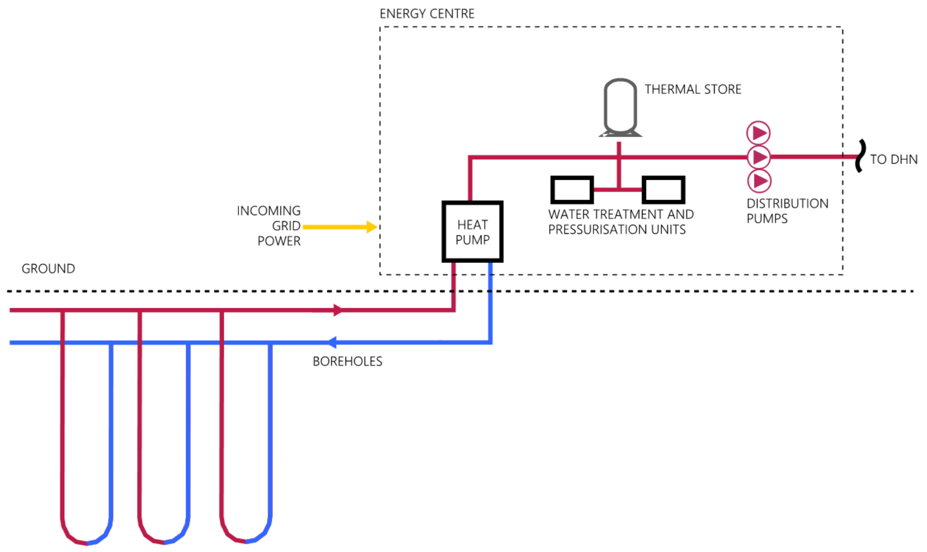

Figure 5—12 GSHP closed-loop system (vertical installation)

For a closed-loop system 100m boreholes can provide only 5-10kW dependent on thermal conductivity of the ground, demand profile and ground temperatures. The following assumptions have been made to understand the number of boreholes and the space requirements of a vertical GSHP closed-loop system:

- 8kW of heat per borehole,
- 8m distance between the boreholes.

It has therefore been estimated that approximately 60 boreholes will be required which equates to 4,000m^2. This means that the scheme requires 4,000m^2 of greenfield land. Considering the density and the layout of the masterplan, this area would probably be found close the school where there is a lot of available land. It should be noted that GSHP systems could be combined with cooling to recharge ground conditions.

In the case that a closed loop system is taken forward a thermal responsive test would be suggested to understand the ground heat yield and optimise the GSHP design accordingly.

Both open-loop or closed-loop systems would require connection to the electricity grid which will be provided on site. In addition the GSHP scheme's viability is highly dependent on Renewable Heat Incentives (RHIs) which increase uncertainty at this point of the study since RHIs tariffs are vulnerable to policy changes.

Anaerobic digestion (AD) combined heat and power (CHP)

In an AD plant biogas is produced by a natural process in which biomass waste is used. This biogas can then be burnt in a CHP unit to produce heat and electricity. This renewable heat is transferred through the heat network to the end consumers and renewable power is fed back to the grid or to end consumers through private wire. A typical schematic and image of an AD plant are provided in Figure 5—13 and Figure 5—14.

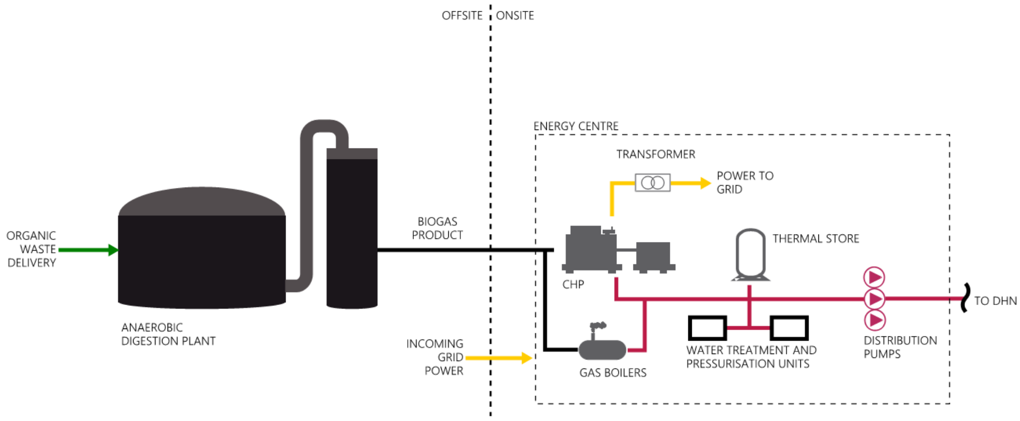

Figure 5—13 AD CHP plant system

Figure 5—14 AD plant

Proposals for an AD plant are being investigated by Brighton & Hove Energy Services Company (BHESCo) to the west of the THV site at Hangleton Bottom. BHESCo calculations are based on 25,000 tonnes of waste material annually which is ~1MW of output of energy, which could be used for electricity, heat or to produce biomethane for direct injection into the gas grid.

For THV this means that the AD plant could potential supply the baseload of the development and the remaining demand would be met by centralised gas boilers. However, connection to this plant would require ~2.8km of gas transmission network for connecting the THV DH scheme, as demonstrated in Figure 5—6.

The transmission network could run alongside the A27 highway corridor. The pipe installation works would need to cross the SNCI. There are no other obvious constraints such as junctions from the road.

Similarly to the GSHP, an AD plant scheme's viability is uncertain at this stage and may be dependent on the Renewable Heat Incentive (RHI), be vulnerable to policy change and proof of yield for the AD plant.

This could however form a source of zero-carbon fuel to contribute to any gas fired components of heat generation in the long term and should be considered as a possible legacy fuel source.

Further steps needed to further the consideration of AD include:

- Review of current AD CHP options and biogas volumetric output, quality and calorific value
- Understand AD scope on transporting the biogas, i.e. via new gas network or vehicular delivery.
- Feasibility to investigate delivery timelines and requirements to allow future transition

Biomass boiler

A biomass boiler burns wood fuel such as wood chips or pellets to produce heat. This heat can then be distributed through the heat network to consumers, as shown in Figure 5—15. Images of an example centralised biomass plant and wood chip storage are shown in Figure 5—16.

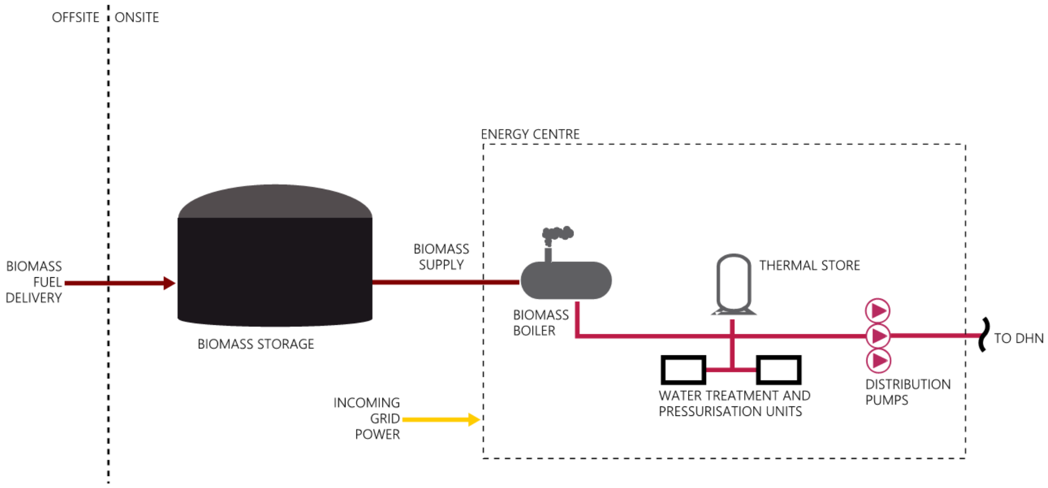

Figure 5—15 Biomass boiler scheme

Figure 5—16 Biomass plant and wood chips

The key considerations for the implementation of a biomass boiler scheme are:

- Space requirements for fuel storage – which is led by biomass boiler size and the profile and amount of heat that will be supplied by the biomass boiler.
- Access on site for delivering biomass plant - the site would be accessible by the A27 road or the A2038, depending on the supply location.
- Biomass local supply - no analysis of local suppliers and costs of biomass has been undertaken for the purposes of this study.
- Impacts of combustion on air quality which may be a constraining factor in urban environments - the site is not located in any of the main air quality management areas (AQMA) and the air quality has been deemed as good by the BHCC Environmental Health team. The best location for minimal impacts on air quality on the site will be set back from road and towards the top of a slope where dispersion conditions will potentially be improved.

Similarly to AD plant and GSHPs, a biomass plant scheme's viability may be highly dependent on Renewable Heat Incentives (RHIs), and vulnerable to future policy changes.

Further steps for the implementation of a biomass boiler district heating scheme include:

- Further investigation into the local biomass supply chain
- Increase clarity on RHI subsidy future.

Renewable Heat Incentives (RHIs)

The Renewable Heat Incentive (RHI) was introduced by the BEIS in order to promote the generation of heat from renewable energy sources. This incentive will help the UK reduce greenhouse gas emissions and meet targets for reducing the effects of climate change. The RHI pays participants of the scheme who generate and use renewable energy to heat their buildings.

The non-domestic RHI Scheme was introduced in November 2011 and includes biomass boilers, GSHP and biogas combustion although the tariffs are subject to change in the future. BEIS has currently announced there will be a 5% reduction to the bio-methane for injection tariff, a 25% reduction to the small, medium and large biogas tariffs and a 5% reduction to the small commercial biomass tariff, effective from 1 October 2016.

Table 5—8 summarised the RHI tariffs for various installation technologies which are valid after 1st of October 2016.

Table 5—8 Tariffs for installation with an accreditation date on or after 1 October 2016

Tariff Name	**Eligible technology**	**Eligible sizes**	**Tier 1 (0< 1314h) (p/kWth)**	**Tier 2 (additional run hrs)** (p/kWth)
Small commercial biomass	Solid biomass including solid biomass contained in waste	Less than 200 kWth	3.10	0.82
Medium commercial biomass	Solid biomass including solid biomass contained in waste	Between 200 kWth - 1MWth	5.24	2.27
Large commercial biomass	Solid biomass including solid biomass contained in waste	1MWth and above	2.05	
Water/Ground-source heat pumps	Ground – source heat pumps and Water-source heat umps	All capacities	8.95	2.67
Small biogas combustion	Biogas combustion	Less than 200 kWth	4.43	
Medium biogas combustion	Biogas combustion	Between 200 kWth - 1MWth	3.47	
Large biogas combustion	Biogas combustion	1MWth and above	1.3	

5.4.2 Carbon dioxide (CO_2) emissions

The CO_2 emission factor for district heating supply options are shown in Figure 5—17, based on BEIS carbon projections for electricity and National Calculation Methodology modelling guide (NCM) for the other fuels. Within this study, an assumption has been made that 30% of the annual heat demand for the heat network is met by additional gas boilers, to cover peak demands that cannot be efficiently met by baseload primary district heating plant. This is a figure derived to compare the different heat sources for this study and is based on previous similar schemes. Heat losses from the distribution network have been considered as 7.5% of the heat delivered as CIBSE Heat Network Code of Practice (2015).

Based on these results AD is the best performing technology in relation to CO_2 reduction, followed by biomass, GSHP and gas CHP. A 45 year lifetime of the heat network is assumed. On account of the projected decarbonisation of the electricity grid, the carbon intensity of heat of the CHP is greater across the lifetime of the plant than when considered with 2016 CO_2 emission factors only. The term carbon intensity of heat refers to the kg of CO_{2e} that are released when one unit of heat is produced. Carbon emissions of gas CHP heat are highly dependent on offsetting the electricity that is cogenerated with heat. In the future it is anticipated that the grid electricity factor will decrease due to grid decarbonisation and therefore the carbon intensity of the heat from gas CHP will increase.

All sources considered have significantly lower emissions than a solution of only gas boilers for heating under the 2015 emissions factor. **Figure 5—17** illustrates the carbon equivalent emissions for the low carbon heat technologies (columns), which change due to reducing electricity emission factor, and for the gas boilers (indicated by the red line) which is constant.

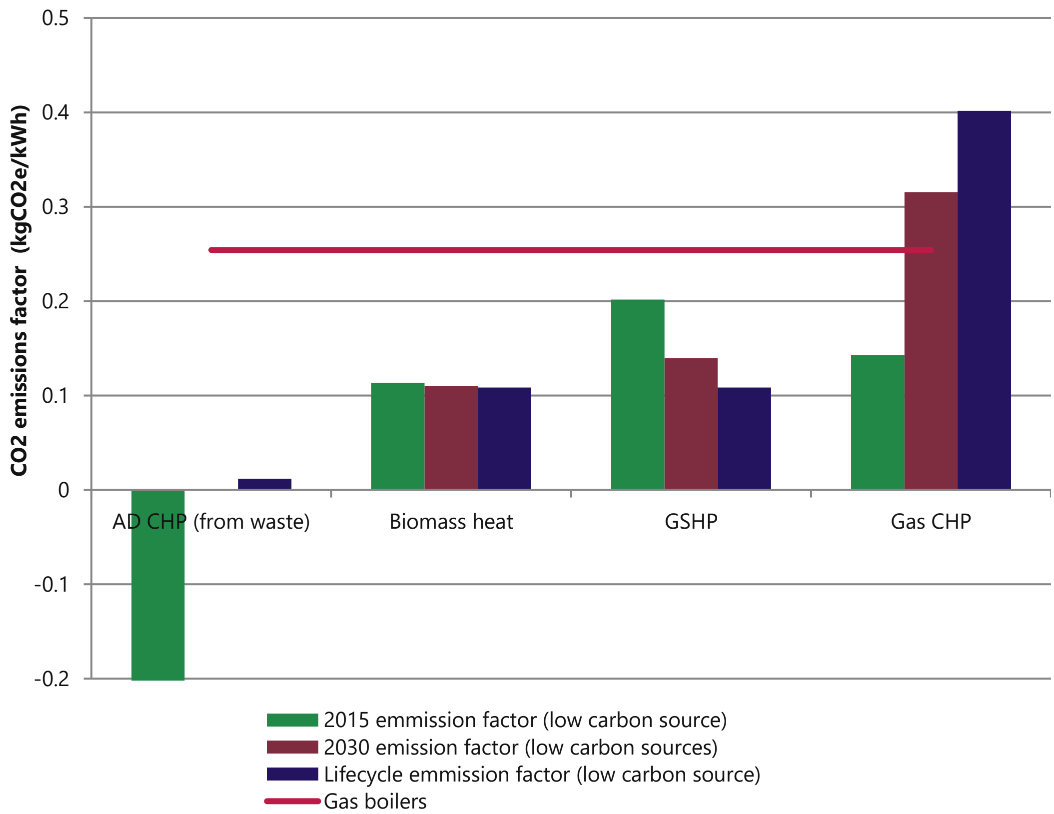

Figure 5—17 Carbon emissions: kg CO_2 per kWh of heat

5.4.3 UK market maturity

Table 5—9 summarises the key considerations on UK market maturity of the considered DH technologies.

Table 5—9 UK market maturity of DH technologies

Heat supply source	Market maturity
Gas CHP	Well proven technology and a standard heat network supply solution. It is a mature technology and has been widely implemented across the UK both within buildings and on district heating networks.
GSHP	GSHP systems are well established in mainland Europe and have become increasingly common in the UK over the last decade coupled with buildings. The use of GSHP coupled with district heating systems is rare. Viability relies on geology/ hydrogeology, EA consent and RHIs.
AD CHP	Currently, the anaerobic digestion sector remains highly fragmented due to the fact that many facilities are often designed to suit project specific requirements. Viability relies on RHIs.
Biomass boiler	Biomass boilers are a mature technology and have been used extensively in mainland Europe for decades. The mainstream use of biomass boilers in the UK only started approximately 10 years ago. Viability relies on RHIs.

5.4.4 Levelised costs

To fully account for the variation in financial incentives, a lifetime unit cost of heat supply in p/kWh has been considered, known as the levelised cost. Levelised cost is an indicator of the minimum value at which energy can be sold over the system lifetime to generate the specified return on investment. Local considerations are included in the financial modelling. **Figure 5—18** shows the levelised cost for each technology, split into gas pipework costs and supply source costs.

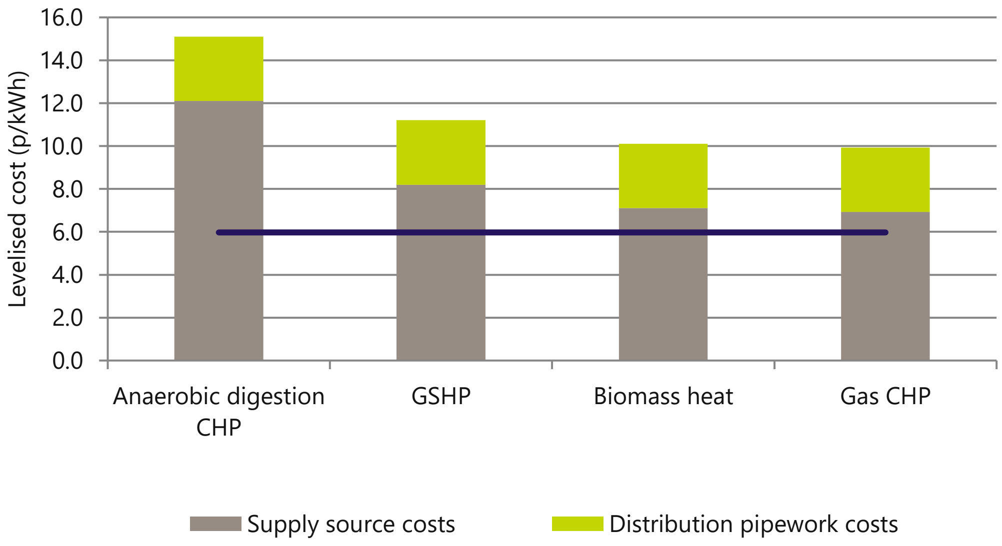

Figure 5—18 Levelised costs including distribution pipework costs

The technology heat supply costs include the ancillary energy centre costs associated with each heat generation technology including top-up gas boiler to meet the peak loads. The AD plant costs include the AD costs as well as the CHP costs. Both capital and operational costs are for the production of one unit of heat. For all levelised cost calculations a project lifetime of 40 years is assumed.

Financial incentives such as the RHIs and the Contracts for Difference (CfD) have been included in the lifecycle cost of the technologies. RHIs are eligible for GSHP, AD CHP and biomass source. CfDs are only eligible for the AD plant.

It should be noted that this assessment is not site specific and assumes that all the heat which is generated by each technology can be sold. Typical UK costs for low carbon technologies and building scale gas boilers have been used. This does not reflect the inputs of the techno-economic model that is described in full detail in section 6.

The definition of levelised cost is included in Appendix F, and detailed Capex and Opex assumptions are included in Appendix I.

Conclusions

The heat source assessment shows that the site has potential for multiple technologies as technical solutions for the site, however for the more innovative solutions such as AD and ground source further studies are required to remove uncertainty (e.g. ground condition investigation for ground source, proof of AD yield and coordination of gas routing).

Gas CHP has been chosen for the purpose of exploring opportunities for the DHN as it has the least uncertainty, is a proven mature technology which is cost competitive, can deliver short term carbon savings as a transition technology to kick-start a network.

It is important at this stage of investigation to select and model a technology that is proven in the UK market, is independent of RHIs to generate revenues, does not rely on ground conditions (e.g. GSHP), and does not have extensive infrastructure or local fuel supply requirements.

It is recommended that further work is undertaken to investigate the potential for of alternative considered heat sources as a part of the feasibility study to investigate the long term potential alternatives. GSHP, AD gas and biomass could all prove to be feasible heat sources after further investigation and de-risking.

AD in particular could form part of a long term transition, supplying bio-methane to the gas CHP to deliver carbon negative heat. Due to the uncertainty this would likely only be possible to consider 10-15 years away when the plant is running and yields proven.

Forecast electrical grid decarbonisation over the next 15 years will see gas CHP perform worse on a carbon emissions basis than the counterfactual gas boiler case. To prepare for this change, the energy centre and wider THV site should be future proofed to allow transition to other technologies as and when they are available/viable. This will allow for further low or zero carbon technologies to be added to the heat network in the fullness of time, to continue achieving the site carbon emission reduction targets.

6 Techno-economic modelling

A techno-economic model is used to assess the commercial potential of the THV DH scheme. The model is made of two components:

- Technical design – connections, heat network and energy centre costed design,
- Techno-economic model – model to assess commercial operation of a scheme.

The techno-economic modelling methodology is shown in Figure 6—1.

The results from the heat demand and heat supply assessment are used within the techno-economic modelling of each scenario.

Heat supply assessment results are used to select the appropriate low carbon technology for the heat network.

From the heat demand results heat demand profiles are created and used to inform the technical modelling process and plant selection.

Costing was carried out to feed into an economic assessment to estimate financial performance of the preferred options for the four scenarios.

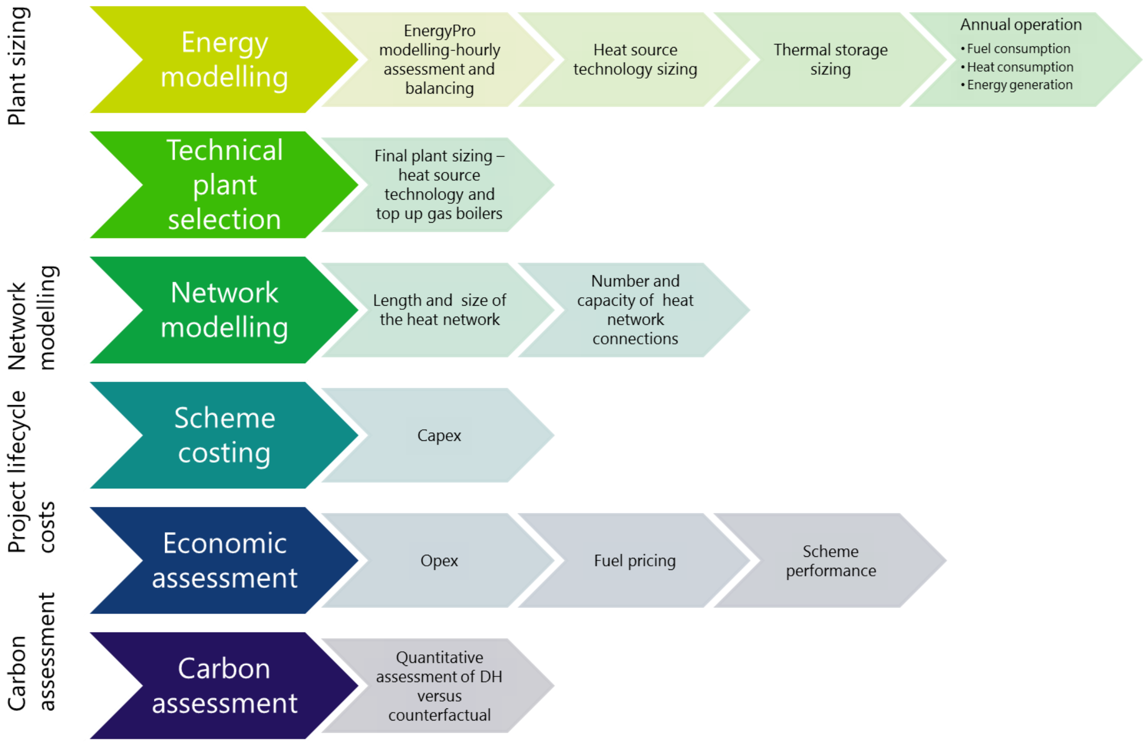

Figure 6—1 Techno-economic modelling process

6.1 Proposed technical scheme design

Based on the masterplan analysis (section 5) the main principles of the gas CHP scheme that is proposed at this stage of the study and has been are:

- The DH scheme that is proposed is a retail scheme. This means that the operator or the manager of the scheme is responsible for final delivery to the individual customer (i.e. each dwelling or flat, or business unit). Within DHN operator responsibilities are HIUs installation, maintenance and replacement
- In masterplan scenarios 1, 2 and 3 all residential and non-residential building are connected to the heat network,
- In masterplan scenario 4 houses are not connected to the heat network,
- Gas fired CHP is selected as low carbon baseload plant with top up gas boilers,
- The gas network is only required for the gas energy centre for scenarios 1,2 and 3. If the heat strategy for the townhouses in scenario 4 is gas boilers, then gas network will be required to supply townhouses with gas.
- Energy Centre and network provides 100% of heat demands to all connected developments,
- The electricity that is generated by the CHP engine is sold back to the electricity grid at grid spill price. The electricity could be sold also to a private consumer under Power Purchase Agreement (PPA). Potential single high electricity consumers onsite are the offices and the school but further investigation is required to understand the private wire opportunities and the profiles of these customers. Off-site potential electricity purchasers under PPA have not been investigated.
- No phased development is considered due to lack of information. Commercial performance is modelled on full build out. (In practice there would be a phased development with the energy centre located in phase 1 – the phasing and impact on performance will require further investigation in further feasibility studies).

The responsibilities boundary of the scheme are illustrated below:

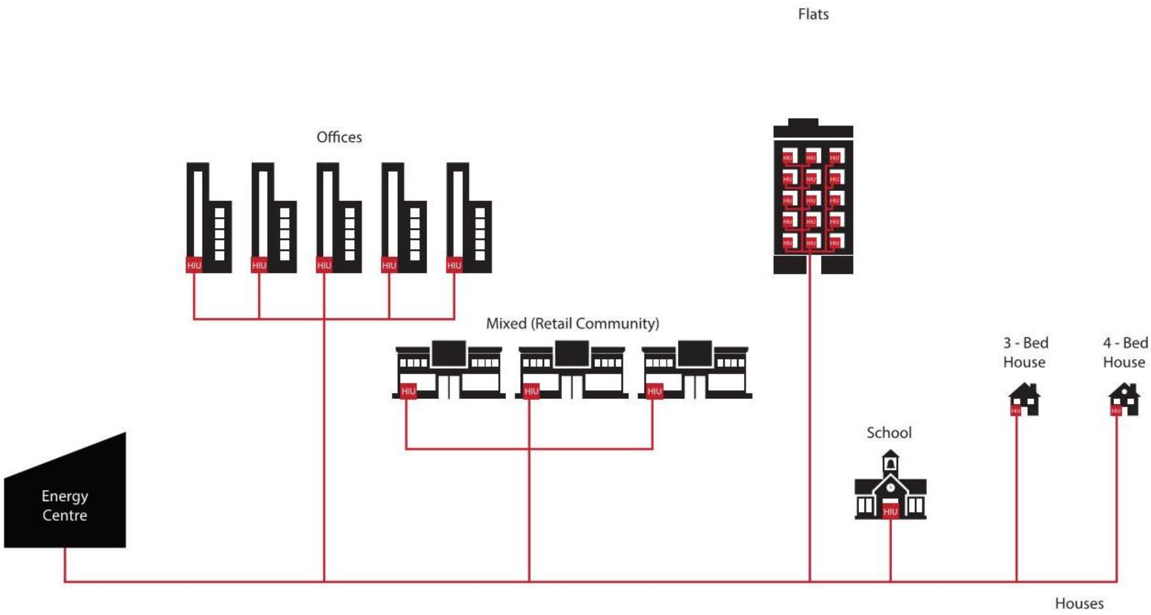

Figure 6—2 Outline DHN schematic

6.2 Energy modelling and plant sizing

EnergyPRO (an energy balance modelling software package) was used to assess the optimum size of CHP and thermal storage for each scenario. Typical good practice operation has been taken as at least 60% (note the EED requires 75% for non-renewable heat from CHP) of the heat demand met by CHP and with full load CHP operational hours above 6,500 hours per year. Models that do not meet these requirements are highlighted red in Table 6—1, which summarises the results of the energy modelling for all the scenarios at various CHP and thermal storage sizes. The yellow highlighted rows indicate the selected models that are technically optimised.

Table 6—1 EnergyPRO results for the three density scenarios[18]

Scenario	Model no.	CHP size (kWth)	Thermal Store size (m^3)	% heat demand met	CHP full load run hours
Scenario 1	1	172	50	37%	8,424
	2	309	50	58%	7,301
	3	309	100	61%	7,628
	4	357	50	61%	6,661
	5	357	100	67%	7,610
	6	401	50	64%	6,188
	7	401	100	73%	7,035
	8	401	150	67%	7,336
	9	527	50	76%	5,632
	10	527	100	84%	6,193
Scenario 2	11	337	50	57%	7,107
	12	337	100	61%	7,622
	13	357	50	58%	6,854
	14	357	100	64%	7,504
	15	357	150	64%	7,522
	16	401	50	61%	6,379
	17	401	100	69%	7,229
	18	401	150	69%	7,269
	19	527	50	73%	5,809
	20	527	100	81%	6,434
	21	527	150	82%	6,518
Scenario 3	22	357	50	53%	7,245
	23	357	100	58%	7,843
	24	401	50	56%	6,754
	25	401	100	63%	7,587
	26	468	50	61%	6,268
	27	468	100	70%	7,224
	28	468	150	70%	7,263
	29	527	50	66%	6,108
	30	527	100	75%	6,899
	31	527	150	76%	6,971
	32	948	100	92%	4,682
Scenario 4	33	200	50	56%	7751
	34	200	100	56%	7793
	35	286	50	70%	6823
	36	286	100	72%	7017
	37	337	50	73%	6029
	38	337	100	79%	6565

[18] CHP engines capacities and efficiencies are taken from manufacturers database

Based on the energy modelling results the following plant sizes have been selected for the four scenarios as the technical optimal solutions, where a large amount of heat is met by CHP and CHP engine operates sufficient amount of hours at full load (above 6,500). The plant sizes, the percentage of the demand met by the gas CHP, the top-up gas boilers capacity and the thermal storage volume for each scenario are summarised in Table 6—2.

Table 6—2 Scenarios model plant sizing

Scenario	Primary heat source	Primary heat plant capacity (kWth)	% heat demand met by primary source	Top-up boiler capacity (kWth)	Thermal storage volume (m^3)
Scenario 1	Gas CHP	401	73%	5,275	100
Scenario 2	Gas CHP	401	69%	5,275	100
Scenario 3	Gas CHP	527	75%	5,275	100
Scenario 4	Gas CHP	286	72%	4,000	100

6.3 Network modelling

A heat network transports heated fluid from the heat generator (i.e. the energy centre) to the end consumer through a buried network. Four parts of the network have been assumed for this study (indicatively shown in Figure 6—3):

- Trunk Main Network: This is the spine route of the network. In this study the trunk main network will follow the route of the main road that traverses the site (green Figure 6—3),
- Branch Network: This part of the network connects to the trunk main and follows the neighbourhood street layout (blue Figure 6—3)
- Service Network: This part of the network connects the branch network and the buildings (red in Figure 6—3)
- Internal Network: This part of the network is located between external pipework and the heat interface units (HIUs) within the buildings and the dwellings. (not shown in Figure 6—3).

Figure 6—3 THV heat network – indicative routes – no EC location shown

The flow diagram in Figure 6—4 shows the steps used in determining network length and size, split in main trunk network, branch trunk network, service and internal pipe network.

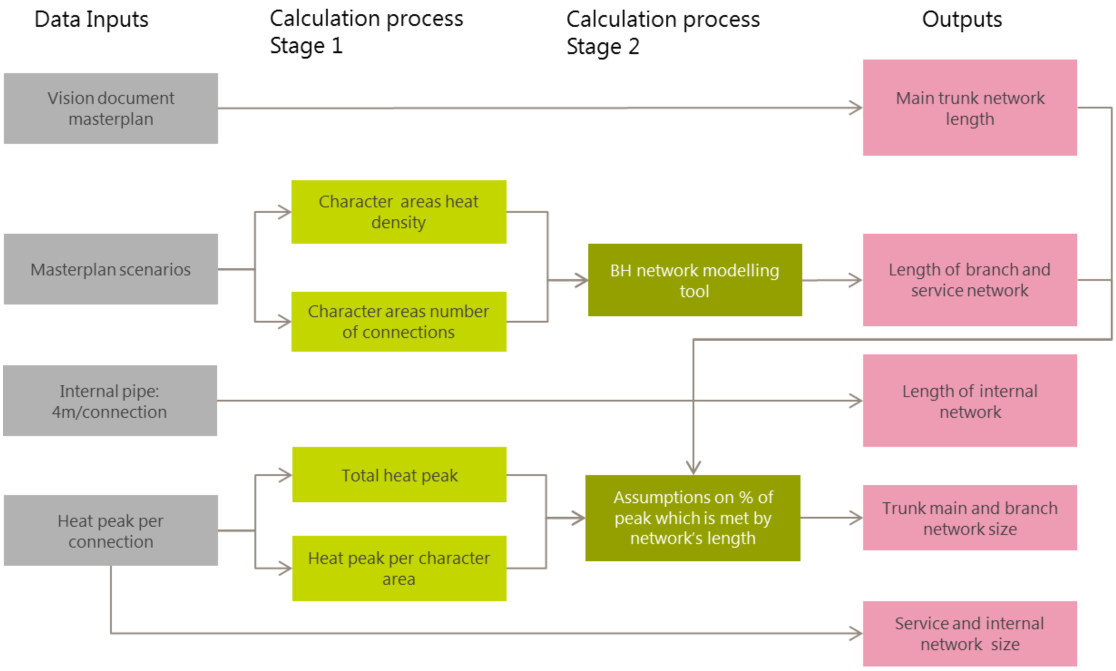

Figure 6—4 Methodology for assessing district heating network

The exact network routes can only be finalised once the masterplan layout is confirmed and are not considered in detail in this study.

It is expected that the heat network will be built alongside the road network and co-located with other utilities – sharing civil works costs as part of a multi-utility installation.

It is also suggested that the heat network phasing runs in parallel with the overall development phasing and that the energy centre is located in close proximity to the first phase of the development.

According to Policy DA7 part of the business areas will be built to primarily attract new residents in the area, hence it is proposed that the energy centre, which is the first phase of the heat network, is built close to this particular area.

6.3.1 Network length

The main trunk network was measured using the masterplan documents available and assuming that the trunk main network runs along the main road.

For scenario 4 it is assumed that only 60% of the main trunk network will be required, since the heat network scheme will not be extended to the houses.

Due to limited details of the masterplan the branch network and the service network cannot be measured directly at this stage. Their network length was estimated using a parametric approach that has been developed by BH, which links the heat density of an area with the number of DH connections and the length of the trunk and service network (Appendix K).

The results were compared against Combined Heat and Power Association (CHPA) and Town Planning Association (TPA) 2008 documents which link the residential density with the length of the network. Figure 6—5 shows the trendline of the CHPA/TPA results and the range of the THV network modelling results. The THV results are marginally lower than the CHPA assessment representing efficient network location in relation to plot connection points. It is assumed that each dwelling has an average of 4m of internal pipework allocated to connect the network to the HIU at each individual dwelling.

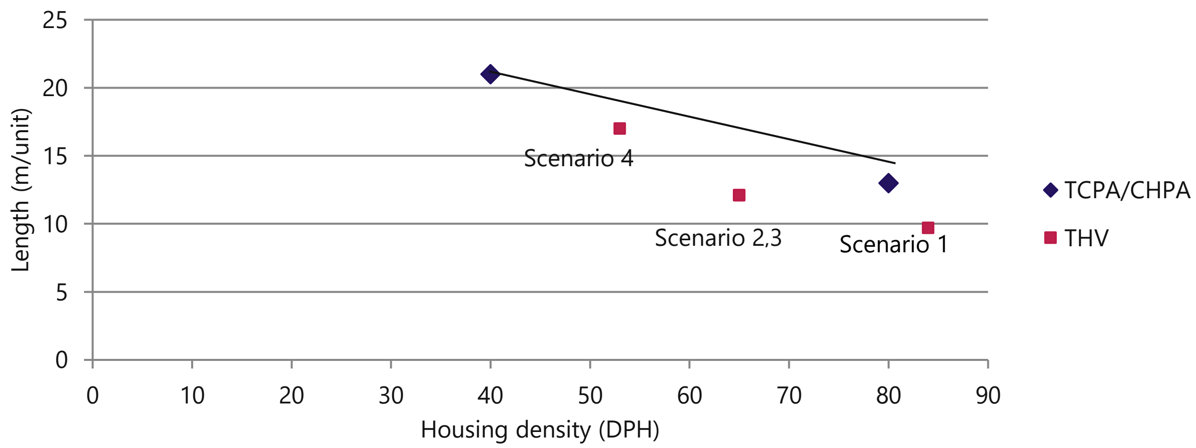

Figure 6—5 Length per unit per housing density

Table 6—3 summarises the housing densities used in each scenario, the heat density and number of connections.

Table 6—3 Connections per scenario

Scenario	Housing density (DPH)				Heat density (kWh/m²)				Number of connections			
	1	**2**	**3**	**4**	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**
Houses	42	44	44		18.7	20.5	20.5	-	386	280	336	
Flats	61	84	84	84	7.8	34.7	34.7	34.7	105	50	60	50
Businesses					7.2	7.2	7.2	7.2	5	5	5	5
Community hub	N/A				27.2	N/A	N/A	N/A	3	N/A	N/A	N/A
School					7.7	7.7	7.7	7.7	1	1	1	1
Mixed uses	N/A	84	84	84	N/A	82.2	82.2	82.2	N/A	4	4	4
Total	**53**	**65**	**65**	**84**					**500**	**340**	**406**	**60**

The results of the network length analysis per scenario are summarised in Table 6—4. The internal network costs are different to the buried network, which is explained in more detail in section 6.4.1.

Table 6—4 Network length per type and scenario

Scenario/Network	Trunk main network (m)	Branch main network (m)	Service network (m)	Internal network (m)	Total (m)	Length /unit (m)
Scenario 1	642	2,468	6,081	2,836	12,027	17
Scenario 2	642	1,225	3,948	2,840	8,655	12.2
Scenario 3	642	1,456	4,698	3,400	10,196	12.1
Scenario 4	385	331	1,186	1,720	3,622	9.7

6.3.2 Network capacity

The sizing of the trunk network (main and branch) was based on assumptions with regards to the percentage of the network length to meet a specific network capacity. This is a method of sizing the network pipes in lieu of a formalised network layout (Figure 6—6). These assumptions are summarised below and are based on BH project experience on heat network development:

- 15% of main trunk network is required to meet 100% of network's capacity,
- 50% of main trunk network is required to meet 20% of network's capacity,
- 35% of main trunk network is required to meet 5% of network's capacity,
- 15% of branch network is required to meet 100% of network's capacity in each character area,
- 50% of branch network is required to meet 20% of network's capacity in each character area,
- 35% of branch network is required to meet 5% of network's capacity in each character area.

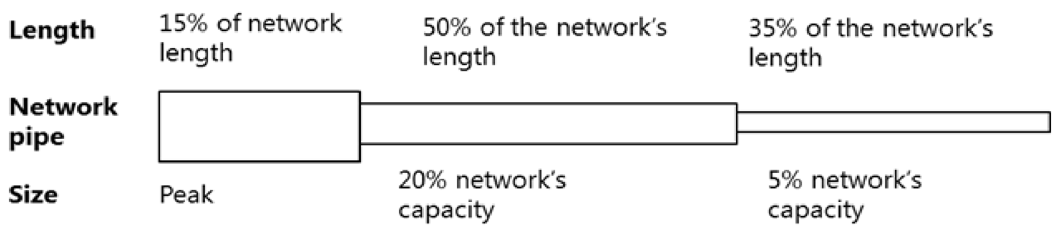

Figure 6—6 Assumed pipe lengths and sizes

The service and the internal network was sized based on the kW capacity of each DH connection.

Table 6—5 presents the total network length (trench length) and size per scenario. Detailed split of the sizes per scenario in trunk main, branch and service network is included in Table 6—5.

Table 6—5 Total network length and size per scenario

Pipe internal diameter (DN) (mm)	Length (m)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
25	8,704	5,562	6,674	1,680
32	837	1,408	1,687	1,095
40	77	104	108	108
50	730	679	544	142
65	838	246	497	246
80	58	58	54	54
100	687	501	489	239
125	-	-	46	-
200	96	96	96	58
Total	**12,027**	**8,655**	**10,196**	**3,622**

Scenario 1 requires 30% of additional network length to scenario 2 for connecting the same number of residential units. This is due to the increased number of townhouses in scenario 1 representing an increase in small (DN25) service pipe to connect the houses.

Line density is a representation of the utilisation of a network, i.e. the amount of heat passed through a length per annum. Table 6—6 shows the comparative line densities for each scenario.

Table 6—6 Line density per scenario

	Line density (MWh/m)
Scenario 1	0.32
Scenario 2	0.48
Scenario 3	0.48
Scenario 4	0.77

Line density for the THV site is low, caused by the relatively low development density and therefore heat density. This results in line heat density (MWh/m of pipe) lower that what it is typically required to make a new network viable (1.8MWh/m).[19] However the commercial performance of a network depends on the capital cost of the system, marginal cost of heat and potential heat retail value, thus a low density can still return commercial performance. Costs, for example, can be reduced by sharing civil costs using a multi-utility trench approach.

[19] IEA /Swiss Federal Office of Energy (2014). *Status Report on District Heating Systems in IEA Countries* (1.8 MWh/m)

6.3.3 Network temperatures

For network sizing the primary network operating flow/return temperatures have been assumed to be 75/45 °C respectively. Best practice, as per CIBSE Heat Networks Code of Practice, would aim to achieve below 40 °C return temperature for a scheme supplying only new buildings. 45 °C has been selected to account for a 5K gain across a the plate heat exchanger.

A summer network temperature relaxation should be considered but as a minimum should still be capable of providing DHW.

The system should be designed as a low temperature system and comply with Heat Network Code of Practice CP1 guidelines for secondary systems. This returns the following benefits:

- High delta T reduces peak volume flow rates leading to smaller pipes and lower costs.
- Maintaining low return temperatures under part-load conditions is important to keep heat losses and pumping energy low.
- Designing for lower operating temperatures will result in higher efficiencies with some types of heat sources, e.g. heat pumps.

Operating temperatures of a heat network are highly dependent on the building services system. Achieving low return temperatures starts with correct selection and balancing of radiators and other heat emitters within the building, which is often the responsibility of the developer and designer and not the heat network owner/operator. In this case it is suggested that the developer needs to liaise with the building designers to specify the building services system.

As all the building will be new, the designers have the opportunity to optimise the temperatures of both the building secondary systems and the DH network. It is recommended that if a DHN is installed a THV specific connection guide should be created and written into any development contracts to include compatible design guidance. Salient points would include:

- Low temperature heat emitters with a temperature regime of 70°C-40°C. Underfloor heating systems will typically operate with floor temperatures below 35°C and typically flow temperatures of 45°C which is advantageous for heat networks as this will results in low return temperatures.
- Optimised internal distribution length, and pipework insulation.
- 2-port control and variable flow systems should be installed throughout.
- Domestic hot water systems (DHWS) should generate instantaneous hot water with use of a plate heat exchanger. This should always be operated at a suitable temperature to mitigate Legionella risk.

6.4 Economic modelling

6.4.1 Project lifecycle costs

An assessment has been made of high level project lifecycle costs for each scenario to inform the business case for progressing opportunities.

Cash flow models have been developed over a 25 year period (typical life of counterfactual boiler plant), given a discount rate of 3.5%. A 40 year period has been also added as a sensitivity. The financial model considers:

- Energy centre capital costs – building, active plant and utility connection estimates,
- Heat network capital costs – buried network,
- Heat connections capital – Heat substations at units and service pipe connections,
- Heat sales,
- Electricity sales,
- Fuel costs,
- Plant replacement fund,
- HIUs maintenance and replacement costs,
- Heat meter maintenance costs
- Staff costs,
- Operation and maintenance of central plant, network and heat meters,
- Annual business rates,
- Gas boilers, gas network PV avoided costs – offset costs that can be included into the financial model which would have been incurred to achieve BAU compliance. In this way, the BAU case costs are included in the financial modelling, giving an indication of the scale of costs of the BAU solution.

Network costing

Network costs are split into pipe costs and civil costs. Civil costs depend on the type of trench digging (soft or hard), on the landscape (i.e. greenfield, urban environment, co-location with other utilities). For the THV site civil costs of the heat network have been estimated based on the following assumptions:

- Soft digging will be required for trench excavation,
- As the site is greenfield buried pipework is assumed to be laid by a multi-utility contractor in a shared utility trench. Civil works for district heating over and above that which would be required for other utilities have been estimated at 15% of the 'standalone' installation estimated for DH in greenfield sites. This 15% derives from the co-location of 5 utilities (heat, electricity, communications, water, sewage) and a central 5% contingency for each utility.
- Internal network pipes have been costed to include the installation within the building.

Gas boilers avoided costs

Gas boilers avoided costs for residential development are taken as £1,500/boiler.

Non-residential avoided costs for gas boilers are taken as £80/kW of heat.[20]

[20] Spon's Mechanical and Electrical Price Book 2015, non-domestic gas boilers

Gas network avoided costs

The gas network avoided costs were calculated to consider the additional costs of the BAU (gas boilers and PVs) which can be avoided in case of the DH solution.

The Southern Gas Networks connections charging methodology was used to determine the cost for the THV development.[21] The cost of a new connection for the first 10 units of the development, and assuming an existing gas main with free capacity is <10m from site boundary was given at £1,104. The cost for the remaining connections was taken as £586/connection. A design cost of £295 was added to the connection costs.

PV installation avoided costs

The PV avoided costs refer to the capital costs that would be required to offset carbon emissions for meeting the development target of 19% carbon reduction improvement against Part L 2013 for residential developments and BREEAM excellent for non-residential developments.[22]

Heat sales

Heat sales revenues have been assumed at a variable heat price of 11.7p/kWh for residential heat demand, which is 15% lower than the cost of heat at BAU case for a town house (13.7p/kWh), as it has been shown at section 3. All standing charges are included within the variable charge. For a similar size property, the cost of heat was crosschecked using the Heat Trust Calculator, returning an estimated at 13.6p/kWh[23].

Non-residential heat sales have been assumed at a variable heat price of 9.3p/kWh, including standing charges. This is 15% lower price than the estimated counterfactual cost of fuel for non-domestic gas boilers, non-domestic standing charges and operational and maintenance costs for a non-domestic gas boiler. As it is shown in section 3, the counterfactual cost of heat is approximately 11p/kWh.

Electricity sales

For this financial modelling a power sales grid spill price has been assumed at 5.5p/kWh.

In case that the site developer has a PPA with a consumer to sell all CHP-generated power the power could be retailed at ~9p/kWh via a 'private wire'. This power price is ~20% below the quoted BEIS (2016) price, i.e. lower than grid electricity price in order to make PPA attractive for purchaser of CHP-generated power. The detailed consideration of the private wire connection is deemed beyond the scope of this study and will need further investigation. To allow initial consideration a higher retail rate has been considered to enable some sensitivity analysis.

Plant replacement fund

The plant replacement fund includes the replacement of gas CHP engines and the gas boilers when the lifecycle of the plant is completed (20 years).

All Capex, Opex and revenue assumptions are detailed in Appendix G and Appendix H.

[21] "Southern Gas Networks Connections Charging and Methodology and Standard Condition 4B statement", June 2016. Available at: https://www.sgn.co.uk/uploadedFiles/Marketing/Pages/Publications/Docs-Connections-Charges/SGN-Connections-Charging-Methodology-Southern-160606.pdf

[22] BEIS 2016, PV installation prices per kW

[23] http://heattrust.org/index.php/test-the-comparator
http://heattrust.org/images/docs/HCC_Further_information_and_assumptions_Final.pdf

6.4.2 Financial modelling – base case

The financial results for the base case financial scenario (i.e. no sensitivity testing applied to scenarios) for both DH scheme and BAU are summarised in Table 6—7. Energy centre replacement costs have been included, this assumes the same technology is installed to replace park of the plant (gas boilers and CHP engine). The cost of the replacement cycles has been equally distributed to the lifecycle of the plant and is included in the annual OPEX.

Table 6—7 Summary of costing and financial modelling results

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
DH scheme				
Energy centre cost (£)	1,625,000	1,625,000	1,933,000	1,373,000
Network cost (£)	2,694,000	1,832,000	2,142,000	709,000
Connection costs (£)	1,978,600	1,989,600	2,301,600	1,261,600
Gas boilers avoided costs (£)	1,247,600	1,247,600	1,427,600	827,600
Gas network avoided costs (£)	421,000	422,000	492,000	258,000
PV avoided costs (£)	1,009,000	1,125,000	1,222,000	871,000
Total net capital cost (£)	3,620,000	2,652,000	3,235,000	1,387,000
Year 1 OPEX (£)	506,600	525,600	617,100	300,000
25 year NPV at 3.5% discount factor (£)	-2,859,300	-1,633,600	-1,874,900	-886,100
25 year IRR	-8.1%	-4.2%	-3.5%	-4.6%
BAU				
Gas boiler costs (£)	1,247,600	1,247,600	1,427,600	827,600
PV installation costs (£)	421,000	422,000	492,000	258,000
Gas network connections costs (£)	1,009,000	1,125,000	1,222,000	871,000

Figure 6—7 illustrates the annual income (electricity sales, non-residential heat sales and residential heat sales) compared to the annual operating costs. The figure shows that the annual income is slightly higher than the annual operational costs. However, the margin is not enough to deliver positive NPV and high IRR for the four scenarios.

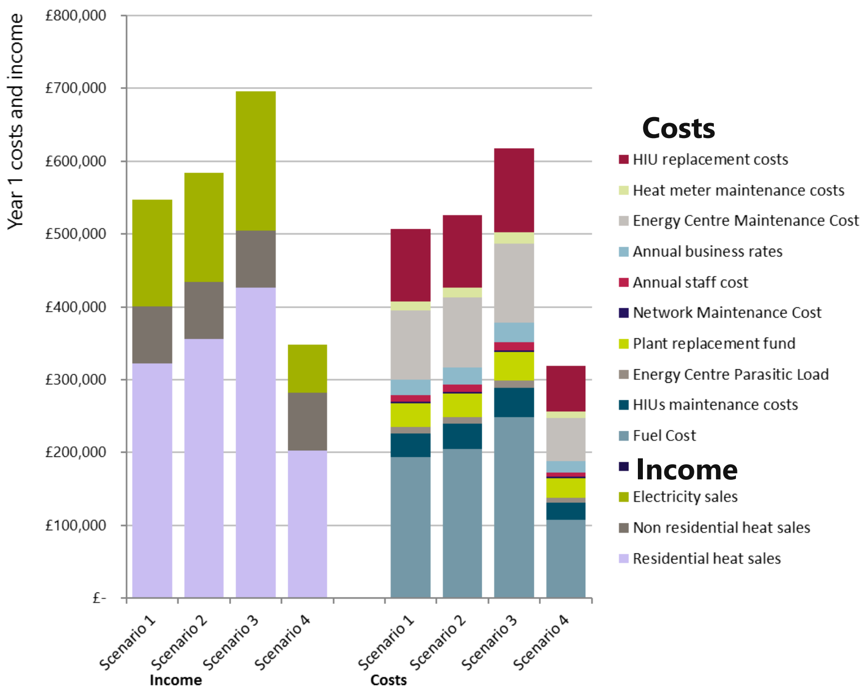

Figure 6—7 Annual income and costs per scenario (year 1)

6.4.3 Sensitivity testing

The techno-economic modelling was carried out under a number of sensitivity tests, including discount rate at 6%, change in the model lifetime and private wire considerations

Sensitivities testings include in various combinations:

- Higher heat sales price – equal to the BAU cost of heat
- Private wire at 9p/kWh
- Plastic pipe – 30% reduction vs. steel pipework,
- Model lifetime – increase to 40 years,
- Capex – +/- 20%. 20% sensitivity is considered sufficient to allow for variation in the capital costs at this stage.
- Grant that is required to for 5% IRR.

Detailed results of the sensitivity testing are included in Appendix J.

Table 6—8 summarises the key results of the sensitivity testing that significantly improve the performance of the scheme compared to the basecase modelling. It also summarises the grant which would be required to get a 5% IRR in each scenario. The 5% IRR is selected as an indicative appropriate level of return to allow for modelling.

Table 6—8 Summary of key financial modelling sensitivity testing

	Model lifetime	IRR Basecase	IRR with private wire	Grant for 5% IRR	CAPEX
Scenario 1	25	-8.1%	-0.7%	£ 3,060,000	£6,200,000
	40	-3.5%	2%	£ 2,900,000	
Scenario 2	25	-4.2%	3.1%	£ 1,850,000	£5,400,000
	40	-0.6%	5.0%	£ 1,650,000	
Scenario 3	25	-3.5%	3.7%	£ 2,130,000	£6,300,000
	40	-0.1%	5.4%	£ 1,900,000	
Scenario 4	25	-4.6%	1.9%	£ 985,000	£3,350,000
	40	-0.9%	4.0%	£ 900,000	

The results indicate that private wire solution significantly increases the performance for scenario 2 to 4. This means that if the developer sells the electricity which is produced in the gas fired CHP plant to a private consumer under Power Purchase Agreement (PPA), this would result in a viable DH scheme for the high density scenarios.

The PPA consumer is now known yet. Heavy electricity consumers onsite are the offices and the school but further investigation is required to understand the private wire opportunities and the profiles of these customers. Off - site potential electricity purchasers under PPA have not been investigated.

Figure 6—8 to **Figure 6—11** illustrate the NPVs of each scenario under the sensitivity testing. The key points of this analysis is:

- Scenario 1 does not produce a positive NPV in the sensitivity test.
- Scenario 2 has a positive NPV when private wire is introduced in the scheme and the heat sales prices are set equal to the cost of heat for the BAU.
- Scenario 3 has a positive NPV, when private wire is introduced in the scheme and when private wire is combined with higher heat sales price.
- For scenario 4, a positive NPV is achieved when there is a 20% decrease in capital cost and when private wire is introduced with higher heat prices.

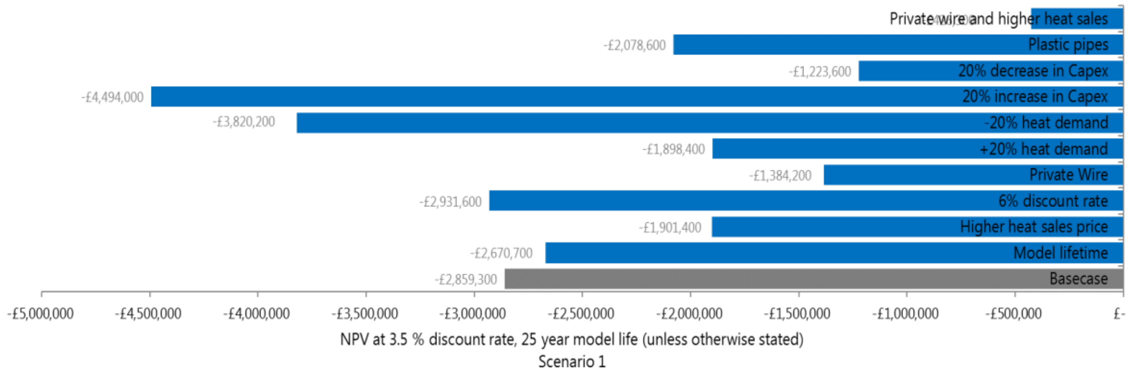

Figure 6—8 Sensitivity testing scenario 1

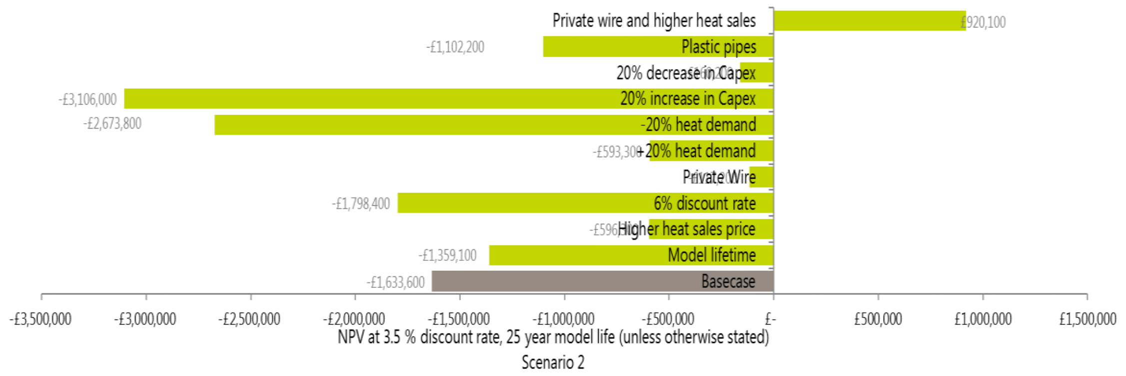

Figure 6—9 Sensitivity testing scenario 2

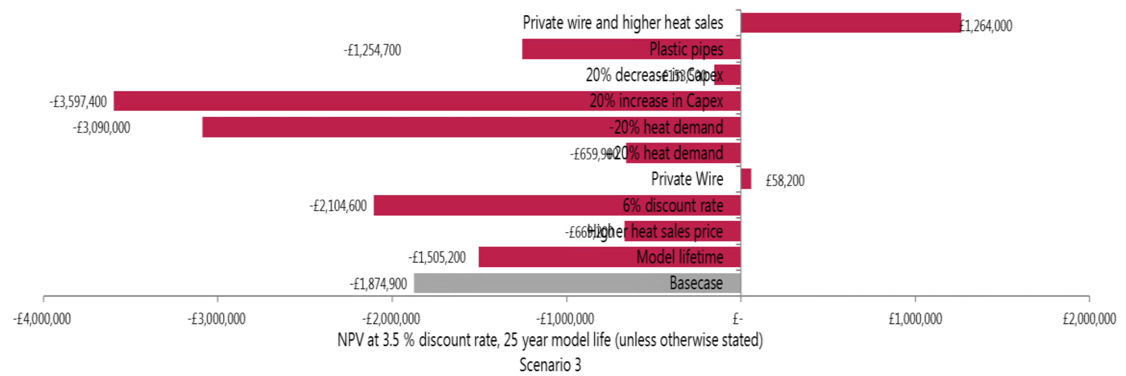

Figure 6—10 Sensitivity testing scenario 3

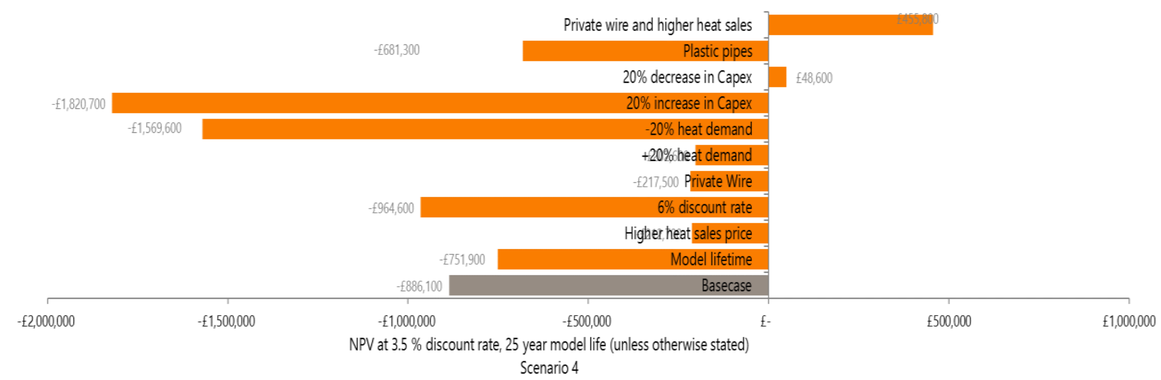

Figure 6—11 Sensitivity testing scenario 4

6.4.4 Financial modelling results analysis

There are a number of key points regarding the financial results of the techno-economic analysis which have also informed the design guidance section.

Scenario 1

Scenario 1 has a negative NPV and IRR (at a 3.5 % discount rate) for the basecase option, despite returning a positive annual operating profit of approximately 8%. This profit is insufficient to deliver a return on the investments.

The low density scenario leads to higher network capital costs per unit of heat delivered compared to other scenarios and therefore it has the worst performance in 25-year and 40-year period. In this scenario use of private wire and 15% higher heat sales price significantly improve the performance of the investment but they do not result in positive NPV.

A grant of £3m would be required for this scenario to achieve 5% IRR.

Scenario 2

Scenario 2 has a negative NPV and a negative IRR of approximately -4.2%(at 3.5 % discount rate,25 years m) . Although this scenario delivers a positive annual operating profit of 11%, this is not deemed sufficient to deliver an acceptable return due to high capital and operating costs.

Private wire solution returns an IRR of 3.1%, while private wire alongside higher heat sales price equal to the BAU cost of heat increase the IRR to 6.9%.

A grant of £1.8m would be required for this scenario to achieve 5% IRR in the base case scenario. In this case the scheme pays back after 15 years of operation.

Scenario 3

Scenario 3 is the best performing option. This indicates that increased unit numbers and therefore density can have a positive effect on performance. Scenario 3 has a negative NPV and IRR -3.5% (at 3.5 % discount rate). In the base case scenario, scenario 3 delivers a positive annual operating profit of approximately 13% of the total annual operating costs, which is not sufficient to deliver a return on the investments only after 22 years of operation.

Compared to scenario 2 (same residential density), scenario 3 performs slightly better due to the 20% increase in dwellings which leads to higher revenues from the heat and electricity sales. The heat line density of the network is similar for both scenarios.

Similarly to the other scenarios, private wire solution presents an attractive opportunity which returns approximately 4% IRR and the simple payback is achieved after 17 years of operation.

A grant of £2.1m would be required for this scenario to achieve 5% IRR in the base case scenario.

Scenario 4

This is the smallest capital cost scheme, removing the low density houses and focussing on the denser apartments and commercial areas. This reduces capital cost of network however this does not compensate for the lower heat revenues.

For this scenario, a ~£0.9m grant would be sufficient to return a 5% IRR. This is ~ one third of the CAPEX and could be accessed through a HNDU grant.

Conclusion

The techno-economic model indicates that a scheme of modest return can be created depending on the heat sales price and the opportunity for private wire. If further costs can be removed from the scheme or funding through a grant e.g. Heat Network Investment Project (HNIP) contribution to the network, the viability of each scenario is improved significantly.

For the low density scenario (scenario 1), there is no room for improving financial performance and grant of £3m is required to make it a viable business case. For scenario 2, an increase in heat sales price by 15% and private wire is considered a viable option. Otherwise a grant of £1.8m could improve the scenario 2 financial performance. Similarly for scenarios 3 and 4, a private wire solution and higher heat sales price suggest an improved business case. If this is not possible, scenario 3 can turn to a viable scheme if £2.1m can be removed from the scheme or be funded. For scenario 4, this amount is reduced to £0.9m – however of a smaller CAPEX..

6.5 Carbon dioxide (CO_2) assessment

The carbon emissions target for the development is a 19% carbon reduction improvement against Part L 2013 for new build residential, and BREEAM excellent for non-residential developments which equates to a 25% carbon reduction against the baseline[24].

The carbon assessment has been conducted for the following THV energy supply solutions

- Baseline: In this solution individual gas boilers are used and minimum energy efficiency measures are applied in order to comply with Part L 2013. This solution does not meet THV development DA7 policy carbon requirements without PV,
- Fabric Improvements: In this solution individual gas boilers are used and fabric improvements against Part L 2013 standards are proposed. This solution does not meet THV development carbon requirements,
- BAU: This is the BAU case for THV as it has been described in section 3. Individual gas boilers are used alongside solar PVs to meet the THV development carbon targets.
  The amount of PVs that are required in the BAU case (individual gas boilers and PVs) to meet the carbon targets for the THV development are:
  - Scenario 1: 4,400m^2 of PVs,
  - Scenario 2: 4,900m^2 of PVs,
  - Scenario 3: 5,400m^2 of PVs.
  - Scenario 4: 3,800 m^2 of PVs.
- DH solution: Gas CHP and peak load gas boilers are used for heat supply. The DH option is well above residential development's minimum target via City Plan Policy CP8 for all scenarios, achieving an approximately 35% decrease in carbon emissions of heat against the baseline for the residential developments. It is therefore closer to complying with the 'exemplary standard in terms of environmental, social and economic sustainability' expected by City Plan policy DA7 for the THV site.
  Commercial buildings have a high proportion of electrical rather than heat loads and therefore less improvement in carbon savings performance is observed. Additional measures to improve the non-residential performance will need to be applied and might include energy efficiency measures (e.g. lighting and electrical devices) or additional PV installation.

Figure 6—12 to Figure 6—15 illustrate the carbon dioxide savings that are achieved in residential and non-residential development against the baseline and the targeted emissions in each scenario.

[24]http://www.breeam.com/breeam2011schemedocument/content/06_energy/Ene01_general.htm

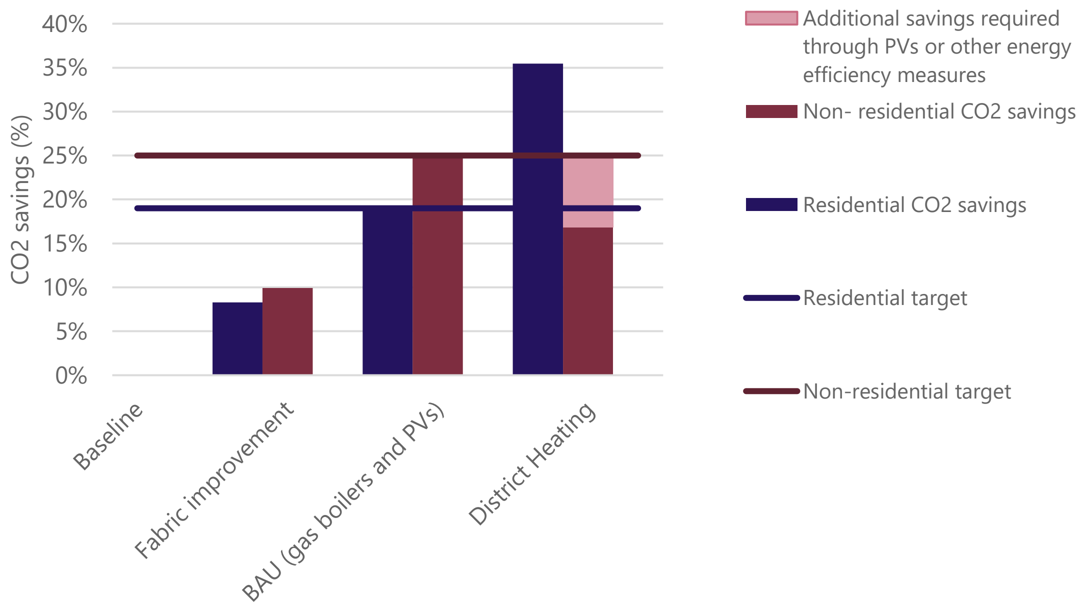

Figure 6—12 CO_2 savings against baseline- scenario 1

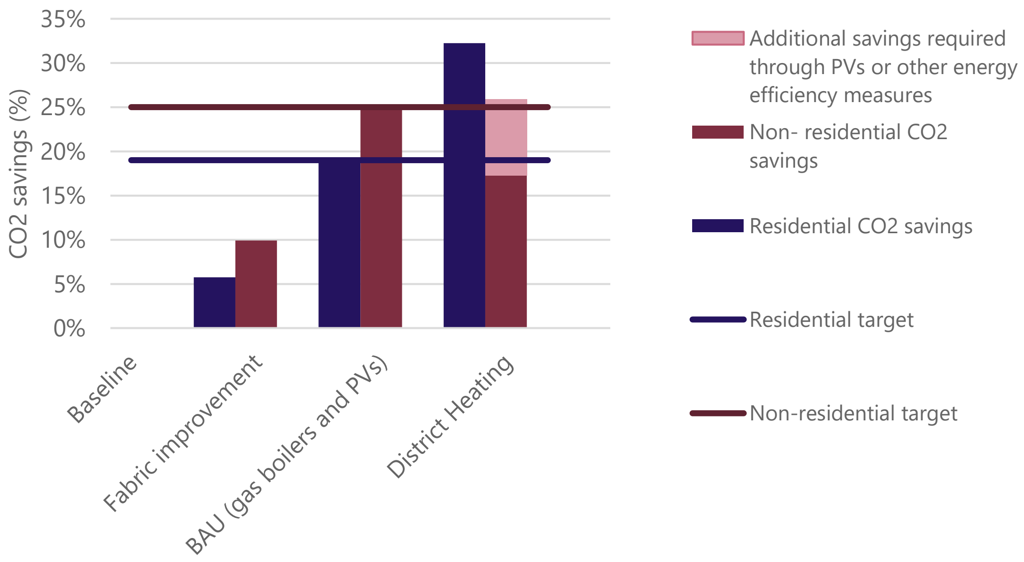

Figure 6—13 CO2 savings against baseline- scenario 2

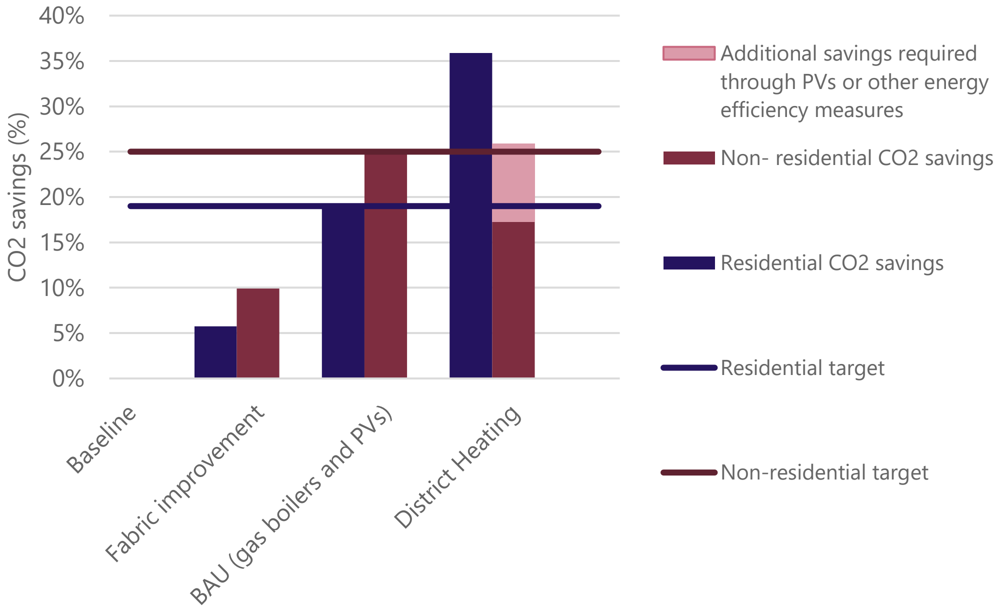

Figure 6—14 CO_2 savings against baseline- scenario 3

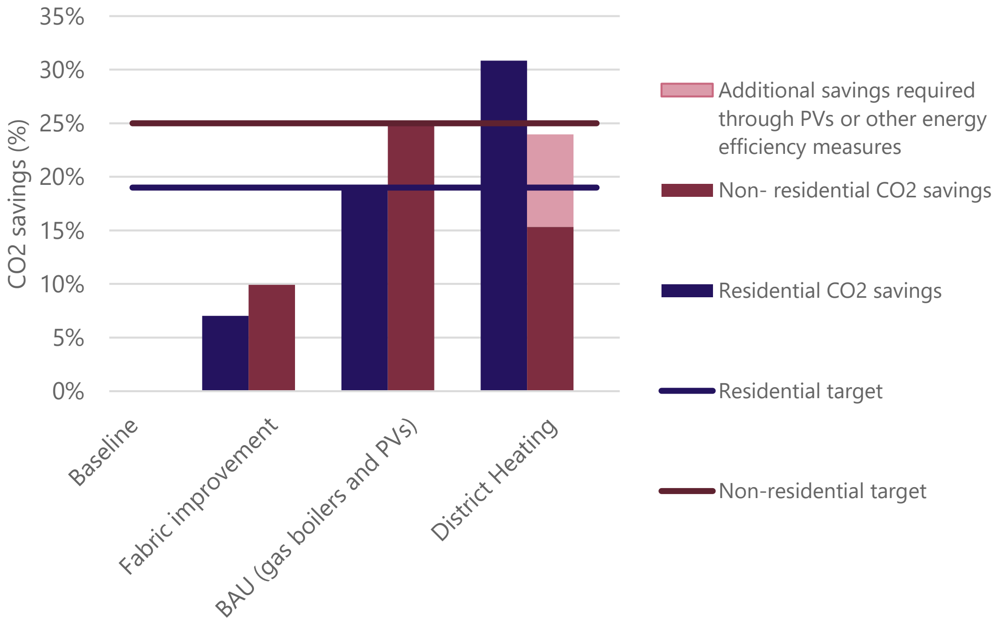

Figure 6—15 CO_2 savings against baseline- scenario 4

7 Delivery road map

The following section sets out a proposed delivery roadmap, should a DH scheme be taken forward, based on the CIBSE Heat Network Code of Practice and sets out other considerations which BHCC and the developer will need to understand and agree to move forward (Figure 7—1).

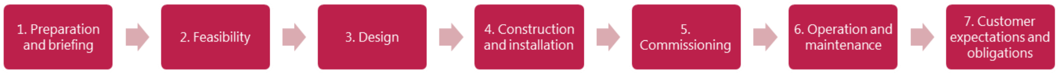

Figure 7—1 Heat network project delivery route map

The technical and engineering feasibility of Decentralised Energy is investigated elsewhere in this report. Commercial considerations for implementing such a solution centre on key factors such as:

- Drivers – drivers for the developer to deliver a DHN and the role of BHCC
- Viability of the business case – determines potential performancet
- Commercial structure – to deliver that business case
- Funding
- Delivery programme

7.1 Drivers

The development of decentralised energy is not always driven entirely by profitable returns and it may be that achieving other objectives such as decarbonising a district, managing energy security or reducing heat costs, among other, may be considered more important. BHCC, through policy and agreement with the developers should agree on the targets of a decentralised scheme.

7.2 Viability of the business case

The decision of the developer to progress with the heat network as a third party will be based on the commercial results available – typically a return of 10-15% would be required to be of 3rd party commercial interest.

At present the results of preliminary modelling indicate that it will be challenging to develop a purely economically viable DH scheme without additional funding or reduction in capital costs. As a result a combination of developer and public sector involvement on the heat network development may support deliverability of an economically viable scheme.

7.3 Commercial structure options

BHCC should consider what role they could take in supporting the development of the DH system and whether and how they can/could act as a facilitator for the developer and private sector.

Different structural options for operation and ownership of heat network elements between BHCC and private sector or 3rd party entities are indicated in Table 7—1. These options require further discussion and clarification of developer and local authority aspirations to develop a proposal.

Upsides from Local Authority involvement include access to low cost finance (see funding sources below) and often lower hurdle rates for project approval.

BHCC involvement would share the benefits of a project but also a share of the risks.

Table 7—1 Ownership and operation options (Heat Networks Code of Practice CP1)

OPTION	Energy centre		Heat network		Heat supply
	Own	Operate	Own	Operate	
A	PSCo	PSCo	PSCo	PSCo	PSCo
B1	LA	LA	LA	LA	LA
B2	LA	PSCo	LA	PSCo	LA
C	SPV	SPV	SPV	SPV	SPV
D1	PSCo	PSCo	LA	LA	PSCo
D2	PSCo	PSCo	LA	LA	LA
D3	PSCo	PSCo	SPV	SPV	PSCo
E1	LA	LA	PSCo	PSCo	PSCo
E2	LA	LA	PSCo	PSCo	LA
F	COCo	COCo	COCo	COCo	COCo

LA = Local Authority
PSCo = private sector company
SPV = public-private special purpose vehicle
COCo = community owned company

7.4 Funding options

Funding for the network and system must also be considered depending on the organisational delivery structure desired.

Sources of funding accessible could include:

- Developer/3rd party capital contribution
- Growth Fund (Strategic Economic Plan)
- Heat Network Investment Project funding open for both public and private schemes. From late 2016 the Heat Network Investment Project (HNIP) – a government funding mechanism supporting the development of heat networks through filling funding gaps. The BEIS HNIP will distribute £320 million of new funding over 5 years for heat networks and was announced in November 2015. Eligibility criteria was consulted on during the summer of 2016 and the scheme is set to launch in Autumn 2016. An application window for pilot schemes is open at the time of writing.

With BHCC involvement the following sources could also be considered:

- S106 contributions or Community Infrastructure Levy (with BHCC involvement)
- Local Authority capital reserves
- Public Works Loan Board – accessible to a scheme with Local Authority involvement

7.5 Delivery programme

If the business case is proved viable, organisational structure agreed and funding secured the scheme can be delivered. An indicative programme of delivery is shown in Figure 7—2 (this is an outline programme and assumes agreement of a delivery structure). Salient points include:

- DH is a specialist discipline with high technical quality required – the business case performance is dependent on delivery for the network life.

- A multi-utility approach is required to civil works (assumed in this modelling) which would need to be highlighted at procurement.
- Construction which would need to be coordinated with the phasing of the development

Compliance with the CIBSE Heat Networks Code of Practice CP1 requires a soft landing approach after installation to monitor and commission. This is a significant undertaking and must be included within the tender process during procurement. The importance of commissioning is paramount to ensure performance is achieved.

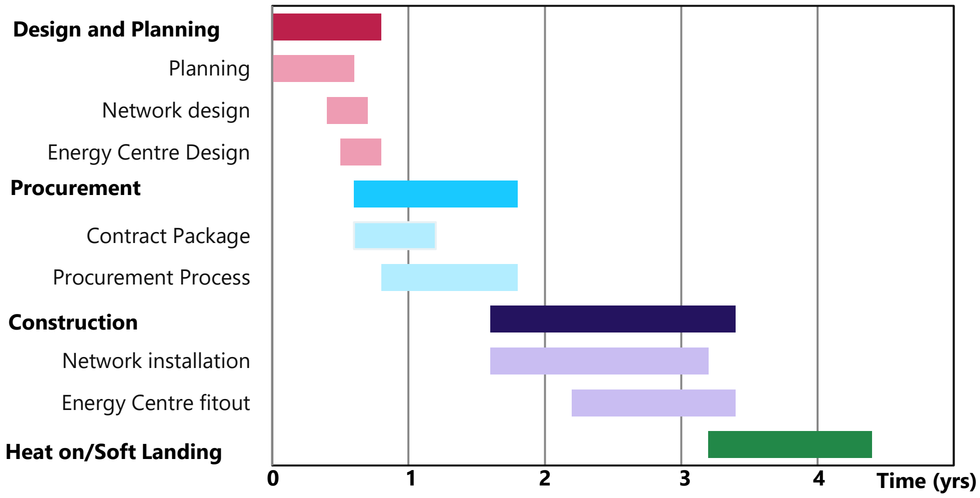

Figure 7—2 Typical Design, construction and installation Gantt Chart

8 Conclusions and next steps

8.1 Conclusions

The techno-economic assessment of the heat network on the THV site shows that:

- The site has potential for a long-term transition away from fossil fuels with multiple potential source, such as gas fired CHP, AD CHP plant, GSHP and biomass plant.
- The AD CHP plant is the best performing technology considering the carbon dioxide emissions savings, followed by biomass, GSHP and gas CHP. All sources considered have significantly lower emissions than a solution of only gas boilers for heating under the 2015 emissions factor.
- A gas fired CHP scheme can deliver short term carbon savings as a transition technology to kick-start a network, since it has the least uncertainty compared to other sources and is a proven mature technology which is cost competitive.
- High density scenarios perform better than low density scenarios for the full scheme scenarios.
- None of the masterplan scenarios provides an attractive business case under the base case financial framework without further support. A scheme of modest returns for scenarios 2, 3 and 4 can be created depending on:
    - the heat sales price
    - opportunity for private wire.
    - Cost reduction through combined utility installation
    - Or in combination with external funding e.g. Heat Network Investment Project (HNIP) contribution to the network, a more economically viable scheme could be created.
- Specific scenario assessments show:
    - Scenario 1 - the low density scheme performs poorly and requires a grant of £3m (of £6.2m CAPEX) to make a viable business case.
    - Scenario 2 – A 6.6% return can be achieved with a 15% increase in heat sales price and private wire electrical sales. Alternatively a grant of £1.8m (of £5.4m CAPEX) could improve scenario 2 financial performance without heat price increase or private wire to 5% IRR.
    - Scenario 3 – A 5% return can be achieved with a grant of £2.1m (of £6.3m CAPEX).
    - Scenario 4 - A 5% return can be achieved with a grant of £0.9m (of £3.35m CAPEX).
- An increase by 20% of the residential units (scenario 3) improves only marginally the performance of the scheme compared to scenario 2, which has same density 700 residential units.

The viability of the heat network is highly dependent on:

- CAPEX - As the site is greenfield buried pipework is assumed to be laid by a multi-utility contractor in a shared utility trench. Civil works for district heating over and above that which would be required for other utilities have been estimated at 15% of the 'standalone' installation estimated for DH in greenfield sites. This is a significant reduction of the capital costs since the heat network costs of the 'standalone' installation account for approximately 70% of the total capital cost for all the scenarios.
- OPEX - This is a retail scheme where the developer is responsible for delivering the final delivery of heat to the individual customer (each dwelling or flat). This results in higher operating costs than a bulk scheme where the heat network operator is only responsible for delivering heat in bulk to major distribution points. This delivers a small margin for profit and long return periods.

- Heat density - the proposed heat density in THV site is not particularly high, since the majority of the developments are houses or low rise blocks of flats which do not reach high heat densities. Focus in the masterplan should be on delivering localised high density heat network zoning. Heat density is subject to change when the masterplan and the buildings typologies are finalised.
- Heat and power sale prices – assessment shows DH to be competitive but further price testing is required.
- Available fund or possibility to reduce capital cost.
- Phasing – although phasing has not been considered in the financial modelling it is suggested that the energy centre be built in a modular mode in the first phase of the development . The heat network should run in parallel with the development's phasing and the other utilities. This approach could help match capital drawdown with the development programme in the initial phases of the development supporting solution flexibility.
- Final masterplan – this study has used assumptions on the final building typologies, the design and the size of the heat network. The final scheme could have different results which would have impact on the viability of the scheme. These risks have been raised in the risk register of the study and require further consideration when deciding on the energy supply strategy of THV.

8.2 Next steps to progress DH scheme

There are high risks associated with the capital costs and the development of the heat network due to lack of the finalised masterplan which would allow a more detailed design and sizing of the heat network. Final heat and electricity demands are also subject to changes in the development programme. The next steps to progress the DH project, considering risks and uncertainties, include heat supply considerations, actions from the BHCC and actions from the developer.

Heat supply considerations:

- Gas and power utility capacity checks should be progressed to understand existing supply opportunities.
- To progress a GSHP open-loop system further steps would require proving of ground conditions, outline steps include:
    - Borehole condition survey and testing to accurately estimate the heat supply potential;
    - Environment Agency (EA) consultation to hold a licence for groundwater extraction from the borehole and rejection;
    - Pump test to accurately estimate the heat supply potential;
    - Viability of low temperature heating systems within the buildings and for network.
    - Drilling another well at a minimum distance of 100m from the existing well would be required for re-injecting the water back to the ground.
- In case a GSHP closed loop system is taken forward a thermal responsive test would be suggested to understand the ground heat yield and optimise the GSHP design accordingly.
- Further steps for an AD plant would require:
    - Understanding of the proposed AD plant configuration, investigate delivery timelines and production potential.
    - Opportunities to transport generated biogas

- The above will inform the proof of delivery that the AD CHP plant could be a long-term transition opportunity.

- Further steps for the implementation of a biomass boiler district heating scheme include:
    - Further investigation into the local biomass supply chain
    - Increase clarity on RHI subsidy future
    - Space requirements for fuel storage (led by biomass boiler size and the profile and amount of heat to be supplied)
    - Access on site for delivering biomass plant

BHCC Actions:

- Incorporate the findings of this study in the development of the supplementary planning document for THV. The design guidance can be used for specific recommendations on the development of the site to increase viability of the heat network.
- Liaise with the developer to understand and inform the distribution of the high and low heat density areas of the masterplan to encourage heat network viability.
- Engage with the developer to explore delivery options and appetite for the local authority and developer to collaborate.

Developer Actions:

- Engage with BHCC to explore any funding options available to make a DH scheme viable.
- It is suggested that the developer (potentially with council support) to undertake further feasibility study to investigate alternative heat sources onsite. Including:
    - GSHP ground condition testing
    - AD delivery timelines and capacity
    - Biomass local supply chain

- When a more fixed masterplan is available further feasibility and design development is required to:

    - Test against a proposed network layout
    - Understand phasing
    - Test techno-economic modelling against phasing
    - Develop the delivery vehicle model – organisational structure
    - Soft market testing for potential operators or private sector interest
    - Begin initial considerations for legal agreements

Appendix A Design Guidance

This chapter sets out the high level design guidance for an on-site DH scheme developed as a result of the viability work. It covers how the DH scheme's viability can be improved for this greenfield site and recommendations on density, phasing and infrastructure to assist delivery of a DH scheme onsite.

Energy strategy recommendation

- To encourage a heat network at THV it is recommended that a heat network zone be developed. A separate individual townhouse solution may be required.

Development density and a heat network zone

- The THV DA7 policy allocates a residential density between 50 ~ 75 dwelling per hectare. In some areas of the site density will be higher and in other areas lower.. It is suggested that a heat network zone be considered where local development density is increased and concentrated. This should include:
    - Mixed use buildings areas (shops, cafes and community hub combined with some flats in scenarios 2 and 3 providing mixed used buildings) – density should be above 84 dwellings/Ha – as per scenario 4.
    - Flats
    - Business areas
    - School
    - Energy Centre
- A heat network zone returns higher line density than a site wide scheme and an increased technical and commercial performance.

Energy centre

- Space allowance should be made for an energy centre approximated as ~500m^2.
- To deliver a future proofed scheme and to allow for transition to future renewable heat sources the energy centre should be located close to:
    - the area of the development with highest block density to minimise distribution costs and efficiencies.
    - the business area of Phase 1 buildings in the Phasing Plan
    - gas infrastructure to reduce utility connection costs.
    - major electrical infrastructure to allow for connection and enable possible future electrification of heat generation
    - road access for simplified delivery and plant maintenance as well as delivery and access for any potential biomass scheme,
    - the A27 corridor which could inter-connect with the AD site (Figure 5-6).

- If the energy centre is located on a higher part of the site this would return lower operating pressures at the energy centre and could avoid potential costs from higher pressure rated plant.

Heat sources

- The site may have potential for GSHP, biomass plant and potentially AD (depending on the development of the off-site plant) though viability assessment has been undertaken for gas CHP only. Biomass, GSHP and AD offer the lowest carbon solutions and potential for the site, it is therefore recommended that the further feasibility and viability assessment be undertaken for these options as part of the masterplan development.
- Gas fired CHP plant is a transition technology and could kick-off the heat network before replacement in the long term by another low carbon technology depending on technology development and maturity – therefore the Energy Centre location should allow for future proofing for future transition.

Phasing

- The energy centre location should follow the phasing plan for the development, i.e. locating the energy centre close to phase 1 buildings. This reduces distribution costs during the initial phases of the development, and safeguards the network from higher future distribution costs in the event that no further phases are developed.
- City Plan Policy DA7 suggests that the first phase of the development includes the business area in order to attract residents on site. It is therefore suggested for THV that the energy centre is located near the business areas of phase 1.
- Modular plant installation should be considered to allow the energy centre capacity to increase with the increase in heat demand as the development progresses. This ensures the energy centre is not oversized and idle plant avoided during the first phases of the development.
- It is suggested that the heat network phasing runs in parallel with the overall development phasing so that it meets the heat demand requirements when these appear on site.
- It is recommended that the heat network installation runs in parallel with the installation of other utilities so that it benefits from reduced trenching costs.

Pipe network

- The DH pipe network routing should be designed and installed to follow the phasing plan.
- The DH pipes should be installed in a multi-utility trench simultaneously with all other utilities – this will reduce trenching costs for the DH network.
- The network should be routed so as to avoid interfering with construction projects in future phases, which will avoid re-laying pipework.
- Design of the heat network should be optimised to minimise the service network length.

Building Services Design

The greenfield nature of the development means the new development designers have the opportunity to optimise and reduce operating temperatures. Building service systems for both DHN and individual systems should:

- Comply with the CIBSE Heat Networks code of Practice for the UK: CP1
- Operate low temperature heat emitters as recommended by the Heat Networks Code of Practice for the UK CP1 working at a maximum of 70°C-40°C should be used. Underfloor and other radiant heating systems will typically operate with floor temperatures below 35°C and typically flow temperatures of 45°C should be used where possible which is advantageous for heat delivery this results in lowered return temperatures,
- Adopt 2-port control and variable flow systems installations in all cases.
- generate instantaneous Domestic Hot Water (DHW) with use of a plate heat exchanger. This should always be operated at a suitable temperature to mitigate Legionella risk.

It is recommended that if a DHN is installed a THV specific connection guide should be created and written into any development contracts to include compatible design guidance.

Heat network temperatures

- The heat network should aim to minimise flow temperatures and maximise the differential between flow and return temperatures.
    - High delta T reduces peak volume flow rates leading to smaller pipes and lower costs,
    - Maintaining low return temperatures under part-load conditions is important to keep heat losses and pumping energy low,
    - Designing for lower operating temperatures will result in higher efficiencies with some types of heat sources, e.g. heat pumps.
- Flow temperatures will be driven by the building systems (assuming a 5K temperature rise across a heat exchanger) installed with a maximum primary temperature of 75°C flow, return temperatures should be as low as possible.
- Adopt best practice, as per CIBSE Heat Networks Code of Practice (2015), which recommends a return temperature of below 40°C for a scheme supplying only new buildings.
- A summer network temperature relaxation should be considered but as a minimum should still be capable of providing safe DHW.

Town house solution

- The heat network zone excludes the townhouses from the DHN, because they have demonstrated low line densities and poor economic performance. Therefore it is recommended an individual Town house solution be developed unless further studies reveal viability for a site wide system.
- The town houses could have an ASHP solution with PV panels in place of individual gas boilers. This delivers low carbon heat in the absence of a DHN connection. ASHP central heating systems are usually based on low temperature heating, therefore fit out of internal wet systems would be consistent with in all dwellings whether connected to the DHN or not. In this way a consistent buildings design approach is applied in the development.

Customer Protection Scheme

- The heat network scheme should use a recognised industry scheme such as the Heat Trust Customer Protection Scheme to provide customer protection in relation to fair pricing of heat.

Design guidance summary

For the THV SPD or any further policy developed for City Plan Part Two, it is recommended that design guidance refer to:

- Energy Strategy recommendation
- Development density and Heat network zone
- Energy Centre
- Heat Sources
- Phasing
- Pipe network
- Buildings services design
- Network temperatures
- Town house solution
- Customer protection Scheme

Appendix B Detailed National Policy Review

National Planning Policy Framework[25]

The National Planning Policy Framework (NPPF) outlines the Government's planning policies for England and how these are expected to be applied. Within the NPPF planning guidance relating to energy is set out in section 10 – "meeting the challenge of climate change, flooding and coastal change". The NPPF encourages local authorities to support the use of low carbon energy sources and the development of decentralised energy systems.

National heat strategy[26]

The national heat strategy sets out an assessment of what decarbonisation of heat supply means in practice and outlines the key priorities in each sub-sector, the main barriers and heat opportunities. The four areas on which the heat strategy focus area:

- Reducing demand for energy in buildings
- Decarbonising heating and cooling supply in buildings
- Decarbonising heat in industrial processes

In the heat strategy document heat networks are considered as a core to the UK's heat strategy, having the potential to play a critical role in helping buildings and industry decarbonise heat supply by 2050. This decade it is expected that heat network opportunities include:

- establishing schemes in the cores of major urban centres where high-density housing (especially new builds) provide sufficient heat loads to make heating networks economical
- extending existing heat networks where schemes are operational to capture customers from the private sector and increase supplier confidence
- making use of existing CHP plants and heat recovered from industrial sites and thermal power plants

National standards for new dwellings

The UK energy standards for buildings are summarised in the Building Regulations 2010[27].

The limiting fabric parameters for new dwellings are summarised in the following table.

Fabric parameters, UK Building Regulations 2010

	Value
Roof	0.20 $W/(m^2K)$
Wall	0.30 $W/(m^2K)$
Floor	0.25 $W/(m^2K)$
Party wall	0.20 $W/(m^2K)$
Air permeability	10 $m^3/(hm^2)$ at 50Pa

[25] National Planning Policy Framework (NPPF)
[26] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48574/4805-future-heating-strategic-framework.pdf
[27]https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/516016/BR_PDF_AD__L1A__2013_with_2016_amendments.pdf

With regard to alternative high- efficiency systems Regulation 25A states that before construction the technical, environmental and economic feasibility of the following systems should be analysed and considered :

- Decentralised energy supply systems from renewable sources
- Cogeneration
- District or block heating or cooling
- Heat pumps

Coast to Capital Local Enterprise Partnership (LEP)[28]

The Coast to Capital Local Enterprise Partnership is a business-led partnership between the private sector and public authorities with the responsibility for driving long term growth. The vision of the LEP is described in the Coast to Capital strategic economic plan, which aims to encourage growth across the Coast to Capital region, through targeted investment in infrastructure and innovation as well as supporting Coast to Capital's business base.

The need for funding support for district heating at the Toads Hole Valley site is referenced in the Strategic Economic Plan, with detail provided in the Appendices document[29].

City Wide Policy

Brighton & Hove City Plan Part One

City Plan Part One is the overarching development plan document for Brighton & Hove which sets out a vision and objectives for the development and growth of Brighton & Hove up to 2030. It:

- Sets clear policies that guide decisions on planning applications;
- Indicates how the plan will be implemented and shows how progress will be monitored;
- Sets out the infrastructure requirements for the city up to 2030 and how these will be addressed

The overall strategy for a sustainable city are set out utrategic objectives to:

- Reduce city's carbon emissions by 42% by 2020 and a reduction of 80% by 2050 over a 2005 baseline of 5.7 tonnes per person.
- Maximise opportunities to support major renewable and decentralised energy infrastructure
- Reduce the ecological footprint of the city and working towards a target reduction of 2.5 global hectares (gha) per person by 2020 and 1.25 gha per person by 2050.
- Raise the standard of sustainable design and construction of homes and buildings in the city to ensure that all new and existing developments contribute to radical reductions in greenhouse gas emissions and resource use,

Three energy related policies are set outin City Plan Part 1:

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[28] Strategic Economic Plan, March 2014.Available at http://www.coast2capital.org.uk/about-us/strategic-economic-plan.html#sthash.gNfra3aS.dpbs and appendices
[29] Strategic Economic Plan, Appendices http://www.coast2capital.org.uk/storage/downloads/strategic_economic_plan_2014_annexes_-1475571581.pdf

CP2: Planning for Sustainable Economic Development. CP2 states that the council will support proposals that drive the city's transition to a low carbon economy and secure the range of benefits this will bring.

CP7: Infrastructure and Developer Contribution. CP7 encourages applications for new developments to deliver sustainable development initiatives including renewable and low carbon decentralised energy systems, schemes and installations, carbon reduction and energy efficiency measures, carbon reduction and energy efficiency measures, and air quality management measures.

CP8: Sustainable buildings. CP8 sets out a number of objectives applicable to new and existing buildings that aim to reduce GHG emissions in the building sector and make development adaptable to the climate change. All development proposals, including conversions, extensions and changes of use will be expected to demonstrate how the development: contributes to a reduction in the city's current level of greenhouse gas emissions by delivering significant reductions in fuel use and greenhouse gas emissions; facilitates on-site low or zero carbon technologies, in particular renewable energy technologies; connects, makes contributions to low and zero carbon energy schemes and/or incorporates provision to enable future connection to existing or potential decentralised energy schemes;

The minimum energy performance standards that are required for new developments are:

- 19% carbon reduction improvement against Part L 2013 new build residential
- BREEAM excellent for major and greenfield non-residential developments
- BREEAM very good for non-major non-residential developments

Local Policy

The specific site allocation and development management policy referring to Toads Hole Valley comprises the Development Area policy DA7 and the draft supplementary planning document as well as city wide policy from City Plan Part One.f

Development Area policy DA7 – Toads Hole Valley

DA7 sets out high standards for sustainability and design. The strategy for the development of Toad's Hole Valley and Court Farm is to secure a modern, high quality and sustainable mixed use development to help meet the future needs of the city, improve accessibility and provide new community facilities to share with adjacent neighbourhoods.

The local priorities to achieve this strategy include: that the development will aim to be an exemplary standard in terms of environmental, social and economic sustainability, achieving a One Planet approach and promoting the city's UNESCO Biosphere objectives.

DA7 also states that any development within this area is expected to meet CP8 requirements and will aim to incorporate infrastructure to support low and zero carbon decentralised energy and in particular heat networks subject to viability and deliverability.

THV Supplementary Planning Document (SPD) and Consultation

The development of supplementary planning documents is part of the city wide and local policy. Policy DA7 states that the site will be the subject of detailed guidance provided in future planning guidance prepared in consultation with landowners/developer and relevant stakeholders. The SPD will allow a more detailed exploration of the opportunities and challenges facing the site and the consideration of the possible ways to address them.

"Issues and Options" is the first stage in the production of an SPD. The purpose of "Issues and Options" is to discuss and build consensus on the type of guidance that should be provided by the SPD. This stage is considered good practice in the case of this important greenfield site. At present nine issues have been identified as challenges for the DA7 and they have been taken to further consultation with stakeholders. Issues related to district energy scheme are:

- Phasing of development and delivery of infrastructure requirements
- Achieve high sustainability and environmental standards through the One Planet Approach.

Appendix C Major developments

Application	Development site	Application Description	Progress	Inclusion in the analysis?	BH comments
BH2009/ 03154	Gala Bingo Hall & Adjacent Car Park	molition of existing building. Redevelopment of site to provide new GP surgery at part ground floor level and part first floor level, new D1/D2 unit at ground floor level and 35 residential units above in part 2, 3, 4 and 5 storey building to include 14	Complete	No	These two developments have been recently built and replacement of recently installed heating systems would be required for connection to a heat network. This is considered unlikely to be cost effective for the development.
BH2010/ 00692	Land West Of Redhill Close Westdene Brighton	Outline application for 31 dwellings (0.62 ha) with public open space (2.11 ha) and approval of reserved matters for layout, access and landscaping.	Complete	No	
BH2010/ 03128	19-27 Carlton Terrace Portslade	Outline application for demolition of existing buildings and erection of 4no blocks of mixed flats/houses totalling 15no units.	Not Started	No	This development is 2.3 km away from the THV site. Its linear heat density when considering connection to the THV site has been estimated as 0.3 MWh/m, which is far below typical density for economic viability (~< 2 MWh/m)
BH2011/ 00228	The British Engineerium	Erection of two storey extension to existing workshop and new single storey building to house exhibition hall. Creation of new underground exhibition area below existing car park. Alterations to provide disabled access facilities including ramps and lif	Completed	No	These three developments have been recently built and replacement of recently installed heating systems would be required for connection to a heat network. This is considered unlikely to be cost effective for the development.
BH2011/ 03358	Maycroft & Parkside London Road &	Demolition of existing buildings and erection of 3no storey residential care home for the elderly with associated facilities.	Completed	No	
BH2012/ 00114	Park House	Demolition of former residential language school and erection of 5 storey block of 71 flats incorporating basement car park and surface car parking to provide 71 parking spaces, including landscaping and other associated works.	Complete	No	
BH2012/ 03734	Sackville Road Trading Estate	Application to extend time limit for implementation of previous approval BH2009/00761 for Demolition of existing	Not Started	No	This development is 1.6 km away from the THV site. Its linear heat density when considering connection

		buildings with construction of new comprehensive development providing a mix of uses focusing around a new public square, including: an A1 foo			to the THV site has been estimated as 0.4 MWh/m, which is far below typical density for economic viability (~< 2 MWh/m)
BH2013/ 02097	Hove Park Depot The Droveway Hove	Demolition of existing buildings and structures, and development of a three-form entry primary school (630 pupils), associated access, parking and landscaping arrangements at former Hove Park Depot, The Droveway, Hove.	Not Started	No	This development is 1km away from the THV site. Its linear heat density when considering connection to the THV site has been estimated as 0.5 MWh/m, which is far below typical density for economic viability (~< 2 MWh/m)
BH2014/ 01042	84-86 Denmark Villas Hove	Prior approval for change of use at first, second and third floor levels from offices (B1) to residential (C3) to form 15no flats.	Comme nced	No	Construction has already started and applications have been approved, as such this is considered a missed opportunity, as assumed for the completed sites.
BH2015/ 00278	Martello House 315 Portland Road Hove	Prior approval for change of use from offices (B1) to residential (C3) to form 28no units.	Comme nced	No	
Existing	West Blatchingt on Primary School.	320MWh/ year as per AECOM 2012 report			Heat consumption is 320MWh/ year as per AECOM 2012 report and is located approximately 400m of the THV site

Appendix D Masterplan scenarios assumptions

Scenario 1: Low-density scenario

Type of load	Dwellings	Housing typology	Dwellings per hectare (DPH)	Land (Ha)
4-bed houses	36	Detached (Vision Document Bungalow)	27	1.33
3-bed houses	350	Terraced (Vision Document Type 1)	44	7.95
3-bed flats	-	-	-	-
2-bed flats	174	2 Storey/2 flats, Typology shown for 50dph (Vision Document, p 11)	50	3.48
1-bed flats (total)	140	Apartment typology, 5 Storey/8 flats(Vision Document Type 3) Apartments (ratio 4xmid floor, 2xground floor, 2xtop floor)	84	1.67
1- bed mid floor apartments	70			
1-bed ground floor apartments	35			
1-bed top floor apartments	35			
Employment site	N/A			4.50
Food growing area				0.50
Secondary School				5.00
Public open space				3.07
Shops and Cafes				0.25
Community facilities				0.25
Roads				9.00
Total	**700**		**48.49**	**37.00**

Scenario 2: High-density scenario

Type of load	Dwellings	Housing typology	Dwellings per hectare (DPH)	Land (Ha)
4-bed houses	36	Terraced (Vision Document Type 1)	44	0.82
3-bed houses	244		44	5.55
3-bed flats	98	Apartment typology, 5 Storey/8 flats(Vision Document Type 3) Apartments (ratio 4xmid floor, 2xground floor, 2xtop floor)	84	1.17
3- bed mid floor apartments	53			
3-bed ground floor apartments	18			
3-bed top floor apartments	27			
2-bed flats	174		84	2.07
2- bed mid floor apartments	87			
2-bed ground floor apartments	44			
2-bed top floor apartments	43			
1-bed flats	124		84	1.48
1- bed mid floor apartments	70			
1-bed ground floor apartments	19			
1-bed top floor apartments	35			
Flats in mixed buildings	24	Mixed buildings with the ground floor occupied by the community facilities and shops and cafes, 4xmid floor, 2x top floor)	84	0.29
1- bed mid floor apartments	16			
3-bed top floor apartments	8			
Employment site	N/A			4.5
Food growing area				0.5
Secondary School				5.5
Public open space				6.14
Shops and Cafes				Included in the mixed buildings required land
Community facilities				
Roads				9
Total	**700**		**61.60**	**37.00**

Scenario 3: High-density scenario and 20% increase in residential units

Type of load	Dwellings	Housing typology	Dwellings per hectare (DPH)	Land (Ha)
4-bed houses	42	Terraced (Vision Document Type 1)	44	0.95
3-bed houses	294		44	6.68
3-bed flats (total)	118	Apartment typology, 5 Storey/8 flats(Vision Document Type 3) Apartments (ratio 4xmid floor, 2xground floor, 2xtop floor)	84	1.40
3- bed mid floor apartments	63			
3-bed ground floor apartments	23			
3-bed top floor apartments	32			
2-bed flats (total)	210		84	2.50
2- bed mid floor apartments	105			
2-bed ground floor apartments	52			
2-bed top floor apartments	53			
1-bed flats (total)	152		84	1.81
1- bed mid floor apartments	84			
1-bed ground floor apartments	26			
1-bed top floor apartments	42			
Flats in mixed buildings	24	Mixed buildings with the ground floor occupied by the community facilities and shops and cafes, 4xmid floor, 2x top floor)	84	0.29
1- bed mid floor apartments	16			
3-bed top floor apartments	8			
Employment site	N/A			4.5
Food growing area				0.5
Secondary School				5
Public open space				4.36
Shops and Cafes				Included in the mixed buildings required land
Community facilities				
Roads				9
Total	**840**		**61.60**	**37.00**

Appendix E Heat demand benchmarks

Type of load	Housing Typology	Assumptions for Benchmarking	Size of typology (m^2)	Space heating benchmark (kWh/m^2)	DHW benchmark (kWh/m^2)	Heat peak benchmark (W/m^2) diversified
4-bed houses	Detached (Vision Document Bungalow)	Detached	90	27.5	18.3	34
4-bed houses	Terraced (Vision Document Type 1)	Terraced	124	22.6	21.8	34
3-bed houses	Terraced (Vision Document Type 1)	Terraced	102	22.6	21.8	34
3- bed mid floor apartments	Apartment typology, 5 Storey/8 flats(Vision Document Type 3) Apartments (ratio 4x mid flr, 2gd flr, 2 top flr)	Apartments mid/ground floor	108	20.1	27.9	43
3-bed ground floor apartments		Apartments mid/ground floor		20.1	27.9	43
3-bed top floor apartments		Apartments top floor		34.9	27.9	51
2-bed flats	2 Storey/2 flats, Typology shown for 50dph (Vision Document, p 11)	Apartments mid/ground floor	79	20.1	27.9	43
2- bed mid floor apartments	Apartment typology, 5 Storey/8 flats(Vision Document Type 3) Apartments (ratio 4x mid flr, 2gd flr, 2 top flr)	Apartments mid/ground floor		20.1	27.9	43
2-bed ground floor apartments		Apartments mid/ground floor		20.1	27.9	43
2-bed top floor apartments		Apartments top floor		34.9	27.9	51
1- bed mid floor apartments		Apartments mid/ground floor	58	20.1	27.9	43
1-bed ground floor apartments		Apartments mid/ground floor		20.1	27.9	43
1-bed top floor apartments		Apartments top floor		34.9	27.9	51
1- bed mid floor apartments	Mixed buildings with the ground floor occupied by the community facilities and shops and cafes, 4xmid floor, 2x top floor)	Apartments mid/ground floor	58	20.1	27.9	43
3-bed top floor apartments		Apartments top floor	108	34.9	27.9	51
Employment site	N/A	Office	25,000	11.2	1.8	56
Secondary School		School	10,000	32.2	6.3	70
Shops and Cafes		Retail	2,500	10.1	13.1	80
Community facilities		Community	2,500	27.1	4.15	70

** Ground floor and mid floor apartments are assumed to have the same heat consumption benchmark per kWh/m^2 as it is assumed that ground floor slab insulation installed to a high standard.*

Appendix F Levelised cost

Levelised cost is a measure of lifecycle cost and is an indication of the minimum value at which energy can be sold over a system lifetime to break even. The levelised costs of each technology option is compared to building based counterfactual solutions in order to give an indication of economic performance compared to business-as-usual solutions.

The technology heat supply costs include the ancillary energy centre costs associated with each heat generation technology including top-up gas boilers to meet peak loads. It has been assumed that 70% of the annual demand is met from the primary heat source and the remaining 30% is met from top-up gas boilers. This is typical for a district heating network in UK as it provides a balance between the high capital cost of baseload plant compared to gas boilers and the operational benefit of the baseload plant.

The calculation used for levelised cost is set out below:

$$LCoH = \frac{cost}{heat\ sales} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t - R_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{H_t}{(1+r)^t}}$$

Where:
LCoH= Levelised cost of heat *(p/kWh heat delivered)*
I_t= Investment expenditures in the year t
M_t= Operations and maintenance expenditures in the year t (including allowance for plant replacement)
F_t = Fuel expenditures in the year t (indexed to DECC Reference Scenario for price growth assumptions)
R_t = Non-heat sale revenue received in the year t (e.g. RHI, electricity sales etc)
H_t= Heating energy delivered in the year t
r = discount rate
N = life of the system

Appendix G Commercial assumptions

Input	Unit	Value	Reference
Heat variable - domestic	£/MWh	117	Based on avoided heat generation cost of gas boilers-domestic, 15% lower price
Heat variable - non-domestic	£/MWh	93	Based on avoided heat generation cost of gas boilers-non domestic, 15% lower price
Electricity export	£/MWh	55	Existing scheme reference for grid spill price
Domestic connection charge – boiler avoided cost	£/unit	1,500	BH project experience
Non-domestic connection charge – boiler avoided cost	£/kW	80	Spons price book 2015
PV avoided cost	£/kWp	£1,500	BEIS 2016 PV installation costs for – average price for installation up to 10kWP
Gas cost at energy centre	£/MWh	22	DECC quarterly energy prices January 2016 for medium consumer
Electricity cost at energy centre	£/MWh	113.25	DECC quarterly energy prices January 2016 for medium consumer
Plant replacement fund	%	40%	% of energy centre capex that will need replacing within below period, including gas boilers and CHP engines
Plant lifetime	years	20	Replacement period for energy centre capex
Staff costs	£/MWh	2.5	Assessment of the Costs, Performance, and Characteristics of UK Heat Networks (DECC 2015).
Heat network maintenance cost	£/MWh	0.6	Assessment of the Costs, Performance, and Characteristics of UK Heat Networks (DECC 2015).
CHP maintenance price	£/kWhe	1.6	Price for the 400kWe engine from Edina range
Energy centre gas boiler maintenance price	£/kW	10	BH experience – upper limit of typical maintenance cost
Electrical import price	p/kWh	10.8	BEIS services price 2016
Business rate	£/MWh/year	6.0	BEIS assessment of the costs, performance, and characteristics of UK heat network 2015
HIUs maintenance cost	£/MWh/year	9.0	BEIS assessment of the costs, performance, and characteristics of UK heat network 2015
Heat meter maintenance cost	£/MWh/year	3.4	BEIS assessment of the costs, performance, and characteristics of UK heat network 2015

Appendix H Capital costs assumptions

Network costs

Size (mm)	£/m-pipe only	£/m - civil work greenfield site	Reference
25	264	210	BH database from UK manufacturers (before applying network cost reduction due to co-location with other utilities)
32	280	220	
40	294	230	
50	300	245	
65	310	260	
80	384	280	
100	408	300	
125	476	340	
200	530	420	

Connection costs

Size	£/unit	Reference
Residential HIU	£2,600	BH database from UK manufacturers.
600 kW	£25,600	
1,200kW	£32,300	
2,500kW	£42,500	
5,000 kW	£68,400	

Energy Centre CAPEX

Item	Reference	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Notes
CHP engine	Ener-G quote	£471,500	£471,500	£701,500	£280,000	-
Engine controls and ancillaries	Allowance	£15,000	£15,000	£15,000	£15,000	
Gas boilers	Cochran quote	£160,000	£160,000	£160,000	£140,000	-
Primary pumps	Previous BH project	£5,000	£5,000	£5,000	£5,000	-
District heating pumps	Spon's M&E Price Book 2015	£20,050	£20,050	£26,350	£16,850	Including valves, insulation and accessories
Expansion and pressurisation unit	BH experience	£56,750	£56,750	£58,000	£40,000	Twin pressurisation pumps and spill unit
Balance of plant and controls	BH experience	£20,000	£20,000	£20,000	£20,000	Mechanical installations, including Public Health, BMS controls
Energy centre substation	BH experience	£50,000	£50,000	£50,000	£50,000	Works related to CHP, includes transformer and HV switchgear
Thermal store	Supplier quote	£100,000	£100,000	£100,000	£100,000	Vertical cylinder
Water treatment plant	BH experience	£10,000	£10,000	£10,000	£10,000	Water softening, pH control, oxygen de-aeration
Dirt separator	BH experience	£4,000	£4,000	£4,000	£4,000	-
Deaerator	BH experience	£2,500	£2,500	£2,500	£2,500	-
Utility connections	BH experience	£65,000	£65,000	£65,000	£65,000	Gas, sewer, incoming LV power
Controls	BH experience	£50,000	£50,000	£50,000	£50,000	
Flue	Supplier quote	£25,000	£25,000	£25,000	£25,000	Includes bends and connections
Enabling works	BH experience	£25,000	£25,000	£25,000	£25,000	Prepare site
Building	BH experience	£280,000	£280,000	£300,000	£300,000	Single storey with 6m floor-to-ceiling height
Testing and commissioning	BH experience	2.0%	2.0%	2.0%	2.0%	-
Engineering package prelims, OH&P	BH experience	17.5%	17.5%	17.5%	17.5%	-
TOTAL	**-**	**£1,625,000**	**£1,625,000**	**£1,933,000**	**£1,373,000**	**-**

Appendix I Levelised costs assumptions

Technology	CAPEX (£/kWth)	OPEX (£/kWth/yr)	Replacement period (yrs)	Fraction of CAPEX to replace (%)
Counterfactual gas boilers	70	6.4	12	90
Biomass heat	2,000	18.1	20	80
GSHP	3,344	10.8	20	80
ASHP	2,230	10.8	20	80
Gas CHP	2,515	20.0	20	80
Anaerobic Digestion CHP (from waste)	12,235	493.5	20	80
Top up gas DH boiler	72	3.6	20	80

Appendix J Financial Modelling Results

S	Sensitivity	Capex (£)			Annual revenues and Opex (£/yr)		Cash flows		Line density
		Net Capital Funding - including connection charges and PV avoided costs	Capital costs - energy centre	Capital costs - network and connections	Yr 1 Annual Opex	Yr 1 Annual Revenue	NPV (£)	IRR for undiscounted cashflow	MWh heat demand per meter heat network
Scenario 1	Basecase	£3,620,000	£1,625,000	£4,672,600	£506,600	£40,100	-£2,859,300	-8.1%	0.32
	Model lifetime	£3,620,000	£1,625,000	£4,672,600	£506,600	£40,100	-£2,670,700	-3.5%	0.32
	Higher heat sales price	£3,620,000	£1,625,000	£4,672,600	£506,600	£100,200	-£1,901,400	-2.7%	0.32
	6% discount rate	£3,620,000	£1,625,000	£4,672,600	£506,600	£40,100	-£2,931,600	-8.1%	0.32
	Private Wire	£3,620,000	£1,625,000	£4,672,600	£506,600	£132,700	-£1,384,200	-0.7%	0.32
	+20% heat demand	£3,620,000	£1,625,000	£4,672,600	£555,500	£100,400	-£1,898,400	-2.6%	0.39
	-20% heat demand	£3,620,000	£1,625,000	£4,672,600	£457,600	-£20,300	-£3,820,200	n/a	0.26
	20% increase in Capex	£4,878,720	£1,950,000	£5,606,300	£532,900	£13,800	-£4,494,000	-14.7%	0.32
	20% decrease in Capex	£2,360,280	£1,300,000	£3,737,900	£480,300	£66,300	-£1,223,600	-2.5%	0.32
	Plastic pipes	£2,812,000	£1,625,000	£3,864,600	£506,600	£40,100	-£2,078,600	-6.7%	0.32
	Private wire and higher heat sales	£3,620,000	£1,625,000	£4,672,600	£506,600	£192,800	-£426,300	2.3%	0.32
Scenario 2	Basecase	£2,652,000	£1,625,000	£3,821,600	£525,600	£58,300	-£1,633,600	-4.2%	0.48
	Model lifetime	£2,652,000	£1,625,000	£3,821,600	£525,600	£58,300	-£1,359,100	-0.6%	0.48
	Higher heat sales price	£2,652,000	£1,625,000	£3,821,600	£525,600	£123,400	-£596,300	1.2%	0.48

	6% discount rate	£2,652,000	£1,625,000	£3,821,600	£525,600	£58,300	-£1,798,400	-4.2%	0.48
	Private Wire	£2,652,000	£1,625,000	£3,821,600	£525,600	£153,500	-£117,200	3.1%	0.48
	+20% heat demand	£2,652,000	£1,625,000	£3,821,600	£577,100	£123,600	-£593,300	1.2%	0.58
	-20% heat demand	£2,652,000	£1,625,000	£3,821,600	£474,200	-£7,000	-£2,673,800	n/a	0.39
	20% increase in Capex	£3,740,920	£1,950,000	£4,585,500	£552,000	£31,900	-£3,106,000	-9.5%	0.48
	20% decrease in Capex	£1,562,080	£1,300,000	£3,056,700	£499,200	£84,700	-£160,200	2.5%	0.48
	Plastic pipes	£2,102,000	£1,625,000	£3,271,600	£525,600	£58,300	-£1,102,200	-2.6%	0.48
	Private wire and higher heat sales	£2,652,000	£1,625,000	£3,821,600	£525,600	£218,700	£920,100	6.6%	0.48
Scenario 3	Basecase	£3,235,000	£1,933,000	£4,443,600	£617,100	£78,500	-£1,874,900	-3.5%	0.47
	Model lifetime	£3,235,000	£1,933,000	£4,443,600	£617,100	£78,500	-£1,505,200	-0.1%	0.47
	Higher heat sales price	£3,235,000	£1,933,000	£4,443,600	£617,100	£154,200	-£669,200	1.4%	0.47
	6% discount rate	£3,235,000	£1,933,000	£4,443,600	£617,100	£78,500	-£2,104,600	-3.5%	0.47
	Private Wire	£3,235,000	£1,933,000	£4,443,600	£617,100	£199,900	£58,200	3.7%	0.47
	+20% heat demand	£3,235,000	£1,933,000	£4,443,600	£679,900	£154,800	-£659,900	1.4%	0.57
	-20% heat demand	£3,235,000	£1,933,000	£4,443,600	£554,300	£2,200	-£3,090,000	n/a	0.38
	20% increase in Capex	£4,510,920	£2,319,600	£5,332,900	£647,800	£47,800	-£3,597,400	-8.4%	0.47
	20% decrease in Capex	£1,960,080	£1,546,400	£3,555,300	£586,300	£109,300	-£153,500	2.7%	0.47
	Plastic pipes	£2,593,000	£1,933,000	£3,801,600	£617,100	£78,500	-£1,254,700	-2.0%	0.47
	Private wire and higher heat sales	£3,235,000	£1,933,000	£4,443,600	£617,100	£275,600	£1,264,000	6.9%	0.47
Scenario 4	Basecase	£1,387,000	£1,373,000	£1,970,600	£319,400	£28,500	-£886,100	-4.6%	0.77
	Model lifetime	£1,387,000	£1,373,000	£1,970,600	£319,400	£28,500	-£751,900	-0.9%	0.77
	Higher heat sales price	£1,387,000	£1,373,000	£1,970,600	£319,400	£70,800	-£212,700	2.0%	0.77
	6% discount rate	£1,387,000	£1,373,000	£1,970,600	£319,400	£28,500	-£964,600	-4.6%	0.77
	Private Wire	£1,387,000	£1,373,000	£1,970,600	£319,400	£70,500	-£217,500	1.9%	0.77
	+20% heat demand	£1,387,000	£1,373,000	£1,970,600	£346,100	£71,400	-£202,600	2.0%	0.92
	-20% heat demand	£1,387,000	£1,373,000	£1,970,600	£292,800	-£14,400	-£1,569,600	n/a	0.61
	20% increase in Capex	£2,055,920	£1,647,600	£2,364,900	£337,600	£10,400	-£1,820,700	-12.1%	0.77
	20% decrease in Capex	£718,080	£1,098,400	£1,576,300	£301,300	£46,600	£48,600	4.1%	0.77
	Plastic pipes	£1,175,000	£1,373,000	£1,758,600	£319,400	£28,500	-£681,300	-3.5%	0.77

	Private wire and higher heat sales	£1,387,000	£1,373,000	£1,970,600	£319,400	£112,800	£455,800	6.4%	0.77

Appendix K Network modelling approach

The heat network modelling is based on apportioning spatial characteristics derived from the detailed analysis of typical neighbourhoods areas across the UK. The test areas were selected based their heat density, then ordered by magnitude and split into equal quartiles.

For each of the test neighbourhood, a spatial analysis has been undertaken in the GIS software package QGIS to estimate network lengths and number of connections for a neighbourhood wide district heating scheme. Road networks and building connections have been drawn using the Ordnance survey 'Open Roads' and 'Adressbase' databases respectively. Road networks have been used as a proxy for a main trunk network, with automated shortest distance lines representing an indicative service network. A manual inspection of network routes was carried out to clean models and remove anomalous networks such as duplicate routes and connections to off-grid remote buildings. An example of GIS mapping for a typical neighbourhood is shown below.

Figure 8—1 Example spatial analysis in GIS showing service pipes connecting to trunk network

For the purpose of the THV study a parametric approach to develop the network length was used using trend lines from the GIS analysis comparing heat density to the length of trunk and service network respectively. The trend lines were applied to the heat demand data which included the heat density and the number of connections in each scenario and character area.

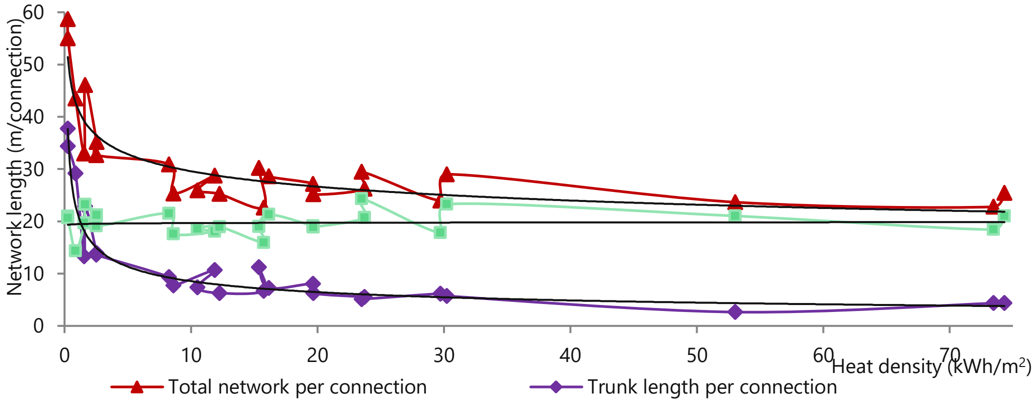

Figure 8—2 Output analysis - trendlines

Appendix L Risk register

BuroHappold Engineering

Project no.:	035279
Project name:	Toads Hole Valley [
Item	Risk register file

Issue	Description	Date
01	Toads Hole Valley heat network study	17/08/2016
02	Toads Hole Valley heat network study	21/20/2016

Score	Probability	Impact
1	Low to zero risk of happening	Little or no impact
2	May happen but not expected	Limited impact on a particular element of the project
3	Likely to happen	Significant impact on the project causing delay, budget overrun or changing the viability of the project
4	Highly likely to happen	Major impact on the project as a whole which prevents project being successful

5	Almost certain to happen	Major impact which prevents entire project being implemented

Risk score	Risk Category	Description
Less than 5	Insignificant	Very low risk event or an event with little or no impact
4 to 10	Low	Likely event with limited impact or an impact or probability which can be kept low
11 to 15	Medium	Major impact with reasonably high level of probability
16 to 20	High	Highly likely major impact which prevents the project being successful
Greater than 20	Very high	Highly likely event with major impact which prevents the porject being implemented

Item Ref,	Risk category	Item	Consequence	Probability (1-5)	Impact (1-5)	Risk (1-5)	Actions
001	Technical	Lack of finalised masterplan with allocated uses	As a result of the finalised masterplan the heat network could not be drawn in detail and the heat line density of the masterplan cannot be verified. This could affect the network costs and, the location of the energy centre and the whole viability of the scheme.	5	4	20	To mitigate the risk, this report has tested different masterplan scenarios and has consulted other projects to verify the network length results.
002	Technical	Uncertainty of the building standards that could have impact on the heat demand that can be met by a heat network.	Improving the buidlings standards to enhance efficiency and meet the carbon targets without can be detriment on the heat network, since the heat sales will decrease and the revenues will be reduced.	2	4	8	The current study has used building benchmarks that suggest improved fabric compared to Part L building regulations and combined with heat network meet the carbon targets of the development. Further steps include additional input from the project design team on the heat consumption and the heat peak of each building.

003	Commercial	Uncertainty of key supply sources, especially regarding the AD CHP plant and the GSHP potential	Uncertainty on the supply sources prevents from fully understanding the opportunities for the heat network	3	3	9	To mitigate the risk, gas CHP has been modelled in the report as it has the least uncertainty, is a proven mature technology and can be used as a transition technology to kick-start a network. Further feasibility is required to de-risk alternative sources.
004	Commercial/ Technical	Low heat density on site, due to low residential density and lack of large non-domestic loads	Low density leads to excessive network length and costs that could be prohibitive for the viability of the project	5	3	15	During masterplan development density should be reviewed as more detailed feasibility is conducted. To mitigate the risk this report has suggested that the main heat network trunk should be deigned to focus on developments with higher density building stock and heat density.
005	Commercial/ Technical	Uncertainty on the phasing of the development	Low heat saled in the first phase of the development could lead to an unsuccesful scheme, since the revenues will be low in the first years of the operation.	5	3	15	No phasing has been considered. A phased installation strategy should be modelled with a modular plant installation strategy. A DHN residential only schemes are usually required more than 400 residential units to be viable, this should inform development timelines.
006	Commercial	Uncertainty of developer's apetite to develop a heat network	In case that the developer has chosen another energy strategy for the site, then heat network cannot be taken forward.	4	5	20	Engage with the developer and help them understand the benefits on carbon reduction using DH and the avoided costs from gas boilers and PV installations that are required to meet the development's targets.

007	Commercial	High capital costs, particularly network costs	Excessive network costs could be prohibitive for the viability of the project	5	4	20	To mitigate the risk civil works cost can be optimised by multi-utility installation process, thjis will need developer buy-in. Further opportunities for cost reduction and ease of installation could be investigated including: plastic pipes for secondary trunk network and pipe services.

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