Brandon Estate
Ground Source Heat Pump
Feasibility Study

Sustainable
ENERGY

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EXECUTIVE SUMMARY

This report presents the findings of the Brandon Estate Ground Source Heat Pump (GSHP) Feasibility study, prepared for the London Borough of Southwark (LBS). The work has been conducted by Sustainable Energy Limited (SEL), and this report will be peer-reviewed by Buro Happold as part of the Local Energy Accelerator (LEA) PDU support for the project. The key conclusions are outlined below.

Energy Demand Assessment

Brandon Estate is made up of 10 housing blocks and a total of 558 dwellings. The blocks are currently connected to a heat network at the site which is supplied by gas boilers. Two commercial buildings are also connected to the network; Brandon Library and Jack Hobbs Community Centre.

Heat usage at the site is metered at the substations that supply each housing block. A heat loss assessment was completed to identify the heat demand at the dwellings and the secondary side building losses. This concluded that the secondary networks currently experience extremely high heat losses, and the 6-pipe riser and lateral networks should be reconfigured to a 2-pipe system utilising the existing domestic hot water (DHW) system. This alongside tertiary upgrades at the dwellings including HIUs, new radiators and copper pipework, will reduce network return temperatures and losses, and increase the scheme's efficiency. The secondary side networks should be replaced in the medium term to further improve the network efficiency.

Energy Centre and Network Assessment

The proposed scheme will utilise the existing energy centre at Brandon Boiler House and the existing heat network pipes, as there is sufficient space in the existing energy centre to incorporate new generation plant and associated equipment and the heat network has recently been replaced.

Proposed Solution

A prioritised heat generation solution of modular GSHPs and a small gas CHP unit has been identified for the Brandon Estate. This solution will minimise energy centre OPEX through the supply of electricity from the gas CHP to one of the GSHPs and reduce the risk relating to highly volatile energy prices. The proposed scheme will also maximise the CO_2e savings in the short term as the CO_2e intensity of electricity generated from the gas CHP is lower than the grid. However, as the grid continues to decarbonise, minimising the electricity generated from the gas CHP will result in greater CO_2e savings. Therefore, it is proposed that the gas CHP is removed from the energy centre once it reaches its end of life (15 years) to allow a greater proportion of heat to be met by the GSHPs. The proposed solution is flexible with the potential for an additional GSHP to be installed in the future, should this be beneficial due to energy prices and CO_2e intensity.

The three phases proposed for the scheme are:

- Phase 1: GSHP and gas CHP installed alongside upgrades to commercial and dwelling heating systems
- Phase 2: Risers and laterals within housing blocks are replaced
- Phase 3: Gas CHP is removed at the end of its lifetime

	Phase 1	Phase 2	Phase 3
Network year	2025	2035	2040
Building heat demand (not including network losses)	5,414 MWh		
Total network heat demand (including network losses)	7,236 MWh	6,253 MWh	
Peak heat demand	2.2 MW	2.1 MW	
GSHP capacity	1 MW		
Gas CHP capacity	200 kWe/252 kWth		-
Total low carbon capacity	1.25 MW		1 MW
Heat demand met by heat pumps, gas CHP and thermal store	6,661 MWh	5,883 MWh	5,444 MWh

	Phase 1	Phase 2	Phase 3
Heat demand met by peak and reserve boilers	575 MWh	369 MWh	809 MWh
% heat demand met by low carbon / renewable technology	92 %	94 %	87 %

Economics

The 40 year economics (with and without leaseholder charges and grant funding), and carbon savings of the network are summarised below.

	Phase 1	Phase 2	Phase 3
Capital costs for each phase (including contingency)	£6,452,116	£1,191,908	-
Total cumulative capital costs (including contingency)		£7,664,024	£7,664,024
40 year IRR	1.1%	1.1%	-1.0%
40 year NPV	-£2,440,704	-£2,726,292	-£3,716,589
40 year IRR with leaseholder contributions	2.7%	2.7%	0.7%
40 year NPV with leaseholder contributions	-£934,194	-£1,037,894	-£2,028,191
40 year IRR with 35% GHNF, 49% HNES funding	4.7 %	4.1%	2.1%
40 year NPV with 35% GHNF, 49% HNES funding	£370,221	£84,633	-£905,664
40 year social IRR	11.7%	11.4%	11.4%
Lifetime carbon savings (40 years)	72,181	75,331	80,336

Under the agreed assumptions, the network will require grant funding to reach LBS' critical success factor (CSF) of a 40 year NPV of £0. There is potential for the scheme to be supported through the Green Heat Network Fund (GHNF) for the energy centre CAPEX and the Heat Network Efficiency Scheme (HNES) for the secondary and tertiary side upgrades. The proposed scheme will also result in an annual OPEX saving of approximately £500,000 (39%) based on the current network operation.

Sensitivity and Risk

Key sensitivity parameters for the prioritised network include:

- Energy tariffs including heat sales tariffs, energy centre fuel purchase tariffs and indexation of energy tariffs
- Capital costs
- Heat demand
- Grant funding

Key risks for the network include:

- Phase 1 likely to require grant funding to be economic
- Abstraction flow rates from the aquifer are not confirmed but are highly likely based on existing nearby boreholes
- Pipework connecting the boreholes to the energy centre will cross existing heat network pipework which may lead to more complicated digging requirements
- Leaseholders may oppose the development of the new scheme however, this should be mitigated as the scheme reduces the annual cost of heat to residents

Summary and Next Steps

It is likely that the scheme will require grant funding to meet LBS' CSF of £0 40 year NPV and deliver the required project benefits.

- Further assess pipework connecting boreholes where it crosses the existing heat network
- Continued discussions with local DNO to ensure electricity connection
- Submit application for GHNF grant funding
- Submit application for HNES funding

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List of Abbreviations

ASHP	Air source heat pump
BAU	Business as usual
BGS	British Geological Survey
CAPEX	Capital expenditure
CHP	Combined heat and power
CoP	Coefficient of performance
CO_2e	Carbon dioxide equivalent
CSFs	Critical success factors
DESNZ	Department for Energy Security and Net Zero
DHN	District heating network
DHW	Domestic hot water
EA	Environment Agency
EC	Energy centre
ESCo	Energy service company
FHS	Future Homes Standard
GA	General Arrangement drawing
GIS	Geographic Information System
GHNF	Green Heat Network Fund
GSHP	Ground source heat pump
HIU	Heat interface unit
HNCoP	Heat Networks Code of Practice
HNDU	Heat Network Delivery Unit
IAG	Interdepartmental Analysts Group
IRR	Internal rate of return
kWh	Kilowatt hour
LBS	London Borough of Southwark
LEA	Local Energy Accelerator
LTHW	Low temperature hot water
Mbus	Meter bus
MTHW	Medium temperature hot water
MWh	Megawatt hour
NOx	Nitrogen oxides
NPV	Net present value
OPEX	Operational expenditure
PDU	Project Delivery Unit
PFD	Process flow diagram
PV	Photovoltaics
RFI	Request for information
SPF	Seasonal performance factor
SPV	Special purpose vehicle
TEM	Techno-economic model
WSHP	Water source heat pump

Glossary

Distribution Network	The circulation pipework (with flow and return) between the energy centre and the substations
District heating	The provision of heat to a group of buildings, district or whole city usually in the form of piped hot water from one or more centralised heat source
Energy centre	The building or room housing the heat and / or power generation technologies, network distribution pumps and all ancillary items
Energy demand	The heat / electricity / cooling demand of a building or site, usually shown as an annual figure in megawatt hours (MWh) or kilowatt hours (kWh)
Combined heat and power	The generation of electricity and heat simultaneously in a single process to improve primary energy efficiency compared to the separate generation of electricity (from power stations) and heat (from boilers)
Green Heat Network Fund	The £288m capital grant funding programme for heat networks announced by Government that opened in April 2022
Heat exchanger	A device in which heat is transferred from one fluid stream to another without mixing - there must be a temperature difference between the streams for heat exchange to occur
Heat Interface Unit	Defined point of technical and contractual separation between the distribution network and a heat user
Heat network	The flow and return pipes that convey the heat from energy centre to the customers – pipes are usually buried but may be above ground or within buildings
Heat offtake opportunity	An opportunity to utilise waste heat from an industrial process including EfW plants using heat exchangers
Heat pump	A technology that transfers heat from a heat source to heat sink using electricity (heat sources can include air, water, ground, waste heat, mine water)
Hurdle rate	The minimum internal rate or return that is required for a network to be deemed financially viable
HNDU	The Heat Network Delivery Unit within the Department for Energy Security and Net Zero (DESNZ)
Internal Rate of Return	Defined as the interest rate at which the net present value of all the cash flows (both positive and negative) from a project or investment equal zero, and used to evaluate the attractiveness of a project or investment
Linear heat density	Total heat demand divided by indicative pipe trench length - it provides a high-level indicator for the potential viability of network options and phases
NPV	Net present value, the value of investment discounted back to the present day using a determined discount rate
Peak and reserve plant	Boilers which produce heat to supply the network at times when heat demand is greater than can be supplied by the renewable or low carbon technology or when the renewable or low carbon technology is undergoing maintenance (also called auxiliary boilers)
Phases	Construction phases in which it is proposed the heat network will be delivered

Project IRR	Internal rate of return (IRR) of a project
Services Provider	Party who will deliver the operational and maintenance services including metering and billing
Social IRR	Internal rate of return of a project, including the additional social benefits of CO_2e savings and improvements in air quality
Social NPV	Social net present value
Substation	A defined point on the property boundary of the heat user, comprising a heat exchanger, up to which the heat network is responsible for the heat supply
Thermal store	Storage of heat, typically in an insulated tank as hot water to provide a buffer against peak demand

1 INTRODUCTION

1.1 General

This report presents the findings of the Brandon Estate Ground Source Heat Pump (GSHP) Feasibility study, prepared for the London Borough of Southwark (LBS). This report will be peer reviewed by Buro Happold as part of the Local Energy Accelerator (LEA) PDU support for the project. The work has been conducted by Sustainable Energy Limited (SEL).

1.2 Project Scope

We were commissioned to undertake a feasibility study for the Brandon housing estate. The scope of the feasibility study included:

- Review existing information including site energy data and tariffs and previous studies at Brandon Estate
- Undertake site visits to the estate energy centre, satellite plant rooms, building level pipework and dwelling heating systems
- Reappraise options for decarbonisation and develop a RIBA Stage 2 design which considers flexible options in the energy centre
- Determine impact of other works at Brandon Estate to improve performance of proposed solution including reconfiguration of secondary side pipework, upgrades at dwellings, substation types, and operating temperatures
- Updated techno-economic model that considers latest capital costs and fuel prices

All work is compliant with the HNCoP, and we considered UK and international best practice.

1.3 Project Background

LBS declared a Climate Emergency in March 2019 and have set a target to achieve net zero by 2030. Residential buildings account for 27% of the borough's CO_2e emissions and LBS began looking at decarbonising their housing estates in 2019. Ground source heat pump (GSHP) feasibility studies were undertaken for several sites (including Brandon) and three were taken forward at Wyndham, Newington and Consort estates. The open loop GSHP schemes at these sites have recently completed commissioning stages and SEL were appointed to undertake a soft landings study to assess their operational performance.

Although initially assessed in 2019, a GSHP at Brandon Estate was not progressed due to insufficient electrical capacity to provide the 805 kVA connection required. The grid constraints have since been resolved and LBS are revisiting the potential opportunities for decarbonisation at the site.

1.4 Critical Success Factors

The key drivers for the council include:

- Improved reliability of the Brandon heating system
- Ensuring affordability for tenants, leaseholders and the London Borough of Southwark (LBS)
- CO_2e savings to contribute to the council's 2030 net zero target

The councils' critical success factors (CSFs) for the Brandon Estate are shown in Table 1.

Table 1: Critical success factors

CSF	Summary	Description	How it will be measured
1	Financial	• The heat network should achieve an NPV of at least 0 at a discount factor of 4% • Low carbon solutions that are eligible for grant funding or other capital contributions should be prioritised	• The economic case and financial case shall be reviewed at every project stage
2	Social	• The heat network must deliver reliable heat to Southwark tenants at an affordable and competitive price • The solution should minimise impacts and disruptions to the tenants • Space heating control and metering of use should allow tenants to efficiently manage their use of heat and overheating should be avoided	• Review and assess heat tariffs against BAU and counterfactual • Consideration of redundancy in system • A solution that provides an installation that does not require tenants to vacate dwellings whilst works is undertaken • Operational noise and access to maintain plant • Design to avoid overheating
3	CO_2e and environmental	• The heat network must enable LBS to meet their Net Zero targets by reducing scope 1 and 2 emissions whilst also considering impacts on scope 3 emissions[1] from refurbishment / construction • CO_2e intensity levels from energy solutions should provide eligibility for grant funding (e.g. < 100 g/kgCO_2e)	• The heat network solution will be assessed to determine the intensity and quantum of CO_2e it will emit over the lifetime of the project
4	Compliance and deliverability	• The heat network solutions should prioritise reusing as much existing infrastructure as possible	• Project to enable removal of 4 out of 6 risers and decommissioning of equipment from the buildings and replace with alternative heat and hot water systems for all tenants

[1] Scope 1: emissions that are made directly by the scheme, Scope 2: indirect emissions, Scope 3: all associated emissions in within the value chain

2 DATA COLLECTION

A review of the existing network area was undertaken as shown in section 2.1. A data collection exercise was then undertaken to enable the current network to be reviewed and assessed. LBS were consulted to inform the data collection exercise, as discussed in section 2.2.3

2.1 Existing Network Connections

The existing network energy centre and connected buildings are shown in Figure 1.

Figure 1: Existing network connections

Details of the housing blocks connected to the existing Brandon heat network are shown in Table 2. Two non-residential buildings are also connected to the network; Brandon Library and the Jack Hobbs Community Centre. Maddock Way and Molesworth House share a substation are a single network connection.

Table 2: Brandon Estate housing block list

Ref	Block name	Building description	No. dwellings					
			Studio	1 bed	2 bed	3 bed	4 bed	Total
1	Bateman House	1958 build 18 storey tower	4	-	64	-	-	**68**
2	Brawne House	1958 build 18 storey tower	4	-	64	-	-	**68**
3	Cooks Road	50s solid brick and panel, exposed roof and floor	3	-	-	-	-	**3**
4	Cornish House	1958 build 18 storey tower	4	-	64	-	-	**68**
5	Cruden House	1958 build 18 storey tower	4	-	64	-	-	**68**

Ref	Block name	Building description	No. dwellings Studio	1 bed	2 bed	3 bed	4 bed	Total
6	Maddock Way	50s cavity brick construction	-	-	6	8	-	**14**
	Molesworth House	50s concrete, brick and panel	9	5	16	28	-	**58**
7	Morton House	50s concrete, brick and panel	6	-	10	21	2	**39**
8	Napier House	50s concrete, brick and panel	4	32	-	-	-	**36**
9	Prescott House	1958 build 18 storey tower	4	-	64	-	-	**68**
10	Walters House	1958 build 18 storey tower	4	-	64	-	-	**68**

The existing secondary side details of connected buildings are shown in Table 3.

Table 3: Building secondary side details

Ref	Building name	Substation name	Details
1	Bateman House	Bateman	• Hydraulic break through a plate heat exchanger to separate the primary and secondary networks • Secondary hot water pipework serves the dwellings' hot water tanks and the space heating pipework flows directly through to the radiators in the dwellings
2	Brawne House	Brawne	
4	Cornish House	Cornish	
5	Cruden House	Cruden	
7	Morton House	Morton	
9	Prescott House	Prescott	
10	Walters House	Walters	
3	Cooks Road	No substation	• Network supplies the dwellings directly with no hydraulic separation
6	Maddock Way	Maddock Way	• Hydraulic break through a plate heat exchanger to separate the primary and secondary networks • Substation serves both housing blocks and the library • Secondary hot water pipework serves the dwellings' hot water tanks and the space heating pipework flows directly through to the radiators in the dwellings • Secondary pipework supplies the library directly with no additional hydraulic separation
6	Molesworth House		
11	Brandon Library		
8	Napier House	Napier	• Limited space within the substation results in no hydraulic separation with and primary network directly supplying the dwellings
12	Jack Hobbs Community Centre	No substation	• Network supplies the building directly with no hydraulic separation

2.2 Engagement with Potential Key Stakeholders

LBS are the main stakeholders in this project. Discussions were held to obtain information such as details of the existing network and energy centre, energy data and tariffs, CSFs and future aims, and building connections. A summary of the key stakeholders is shown in Table 4.

Table 4: Summary of engagement with key stakeholders

Contact	Site/organisation	Role/interest
Tom Vosper	LBS	• Strategic Project Manager – Heat Networks
Gabriela Torres	LBS	• Contracts Officer
Steve Humphries	LBS	• Building Management Services Department

3 ENERGY DEMAND ASSESSMENT

3.1 Heat Network Elements

A district heat network can be broken down into three main areas which are the primary, secondary and tertiary elements of the network. The characteristics of each network element are summarised in Table 5 and Figure 2.

Table 5: Primary, secondary and tertiary network characteristics

Network element	Description
Primary network	• This is the heat distribution flow and return pipework (normally buried) that runs between the energy centre and the connecting buildings and carries heat generated at the energy centre for use in the connecting buildings
Secondary networks	• These comprise the heat distribution pipework and associated components installed within the connecting building and may include space heating circuits and hot water circuits. Secondary networks are either directly connected to the primary network or hydraulically separated from the primary network via a thermal substation to provide an indirect connection to the primary network. In residential buildings, the secondary networks are normally separated from the tertiary networks via a heat interface unit (HIU) installed within each dwelling
Tertiary network	• These are the heating systems installed within each dwelling, and normally comprise a space heating circuit (e.g. radiators or underfloor heating) and hot water circuits (supplying taps and showers etc)

A residential heat network with direct connection of primary and secondary networks is illustrated in the figure below.

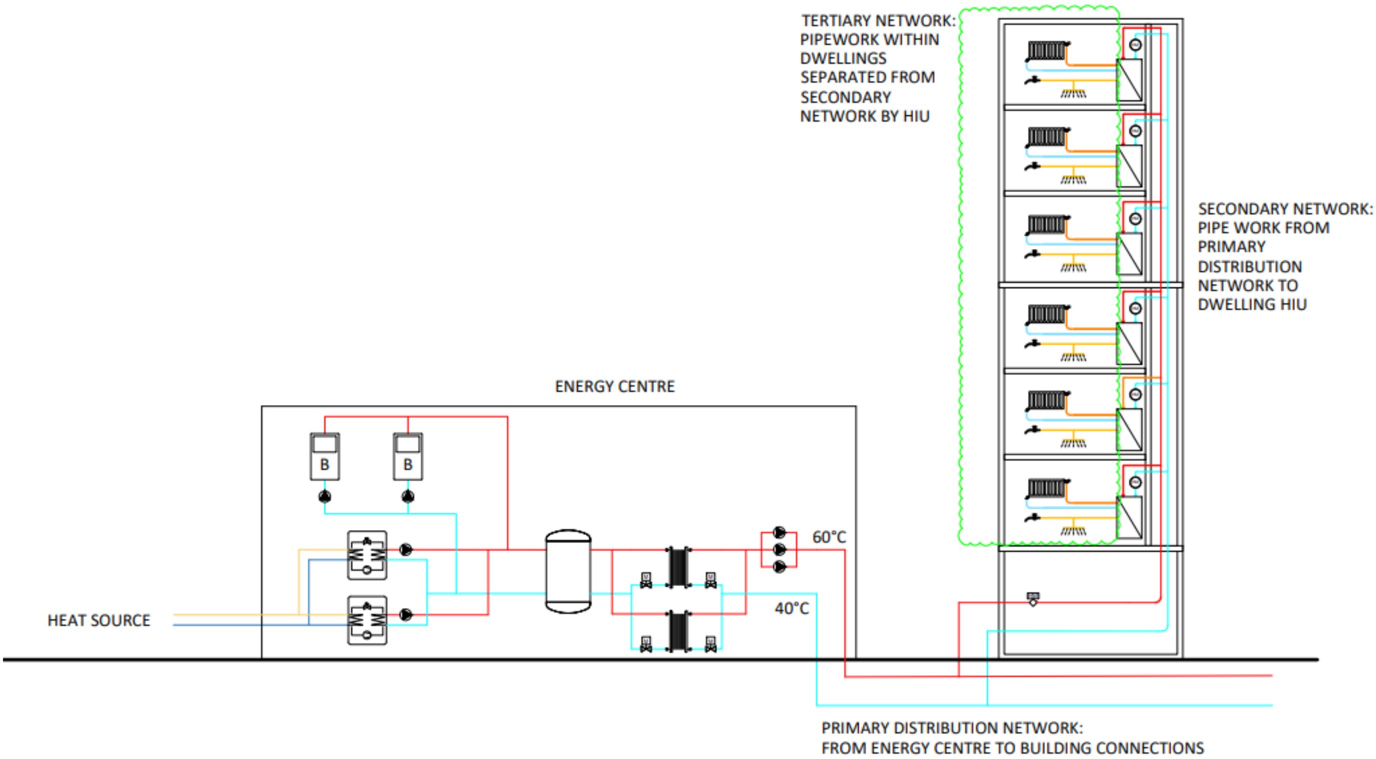

Figure 2: Primary, secondary and tertiary network elements

3.2 Energy Demand Assessment

Energy demands for the network connections have been assessed based on data available from the LBS building management system (BMS) for the Brandon Estate. For the buildings without data in the BMS (Jack Hobbs Community Centre, Brandon Library and Cooks Road), the energy demands and profiles were modelled to in line with Objective 2.1 of the CIBSE / ADE Heat Networks Code of Practice (to achieve sufficient accuracy of peak heat demands and annual heat consumptions) and comply with Part L of the relevant Building Regulations. In line with best practice, hourly annual energy demand profiles were generated using in-house modelling software which apportions demands to hourly loads over the year, considering degree day data[2], building use and occupancy.

Heat meters are located at each of the residential block substations and are recorded in the LBS BMS system. However, not all heat meters had recorded sufficient data to allow the modelling of the buildings' annual heat demands. Data for Morton House, Napier House, Maddock Way, Molesworth House, Prescott House and Cornish House was used in the assessment. Prescott and Cornish are two of the six identical tower blocks within the estate and therefore the energy data at these sites was applied to the remaining four blocks. However, the data recorded by the substation heat meters includes the heat losses throughout the building as well as the actual heat demands from the dwellings. Therefore, a heat loss assessment on each of the buildings was required to determine the heat demand of each dwelling.

3.2.1 Heat Loss Assessment

The housing blocks throughout the estate have 6-pipe secondary networks which consist of 2 domestic hot water (DHW) pipes (1 flow, 1 return) and 4 space heating pipes (2 flow, 2 return) as shown in Figure 3. This system results in significantly higher heat losses than a 2-pipe system as shown in Figure 2.

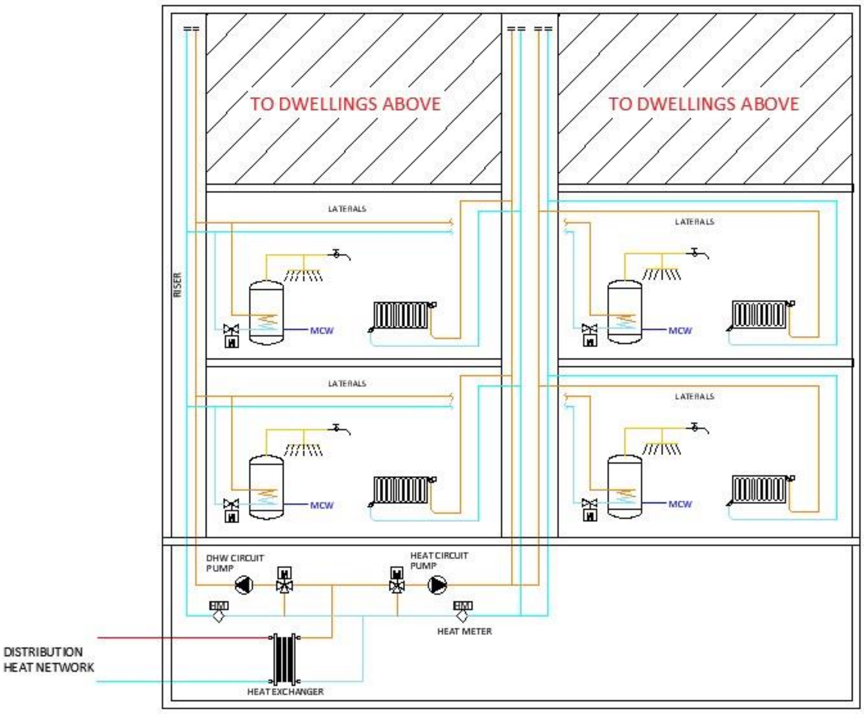

Figure 3: Secondary networks within the Brandon Estate housing blocks

[2] Degree days are a type of weather data calculated from outside air temperature readings. Heating degree days and cooling degree days are used extensively in calculations relating to building energy consumption. They are used to determine the heating requirements of buildings, representing a fall of one degree below a specified average outdoor temperature (15.5°C) for one day.

DHW Network Losses

The heat losses from the DHW secondary circuit were estimated by analysing the building heat usage on the warmest day of the year (19th July 2022). This circuit includes the risers and laterals throughout the building and the hot water tanks in each dwelling. It is assumed that the heat usage would be minimal on very warm days however, the heat usage does not fall below 32.5 kW in Prescott House, as shown in Figure 4. Therefore, it is assumed that these are the standing losses within the DHW system.

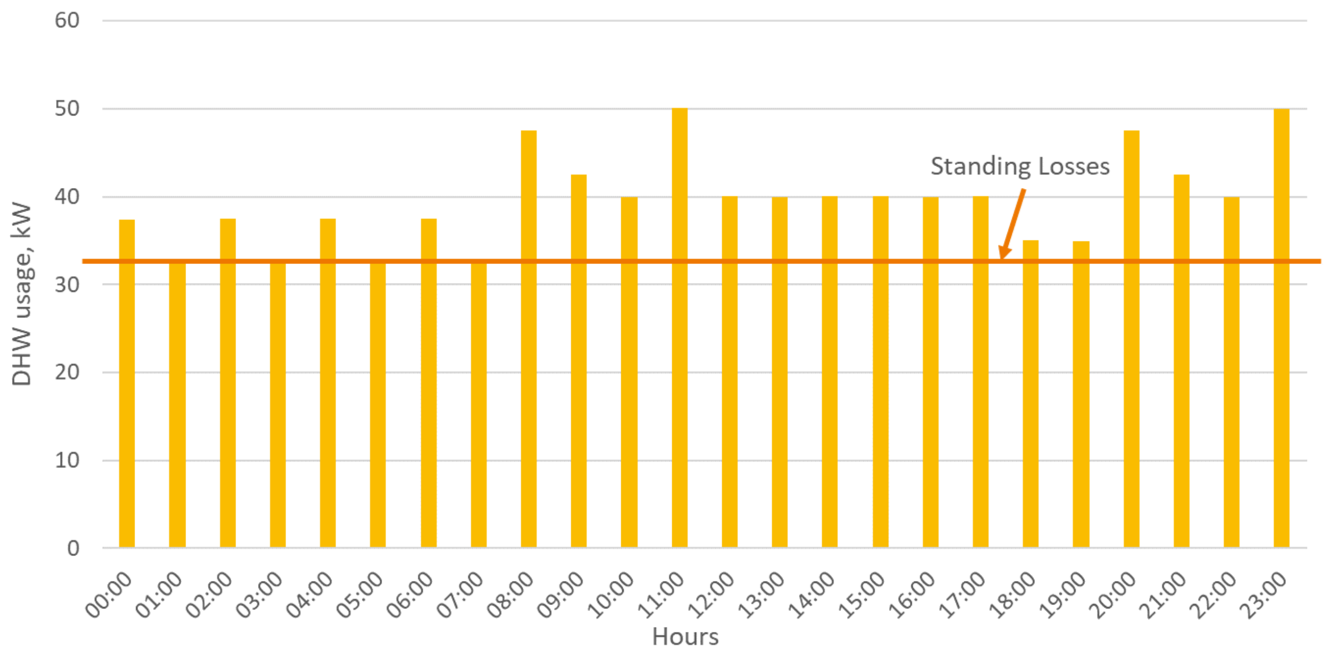

Figure 4: Prescott house DHW usage during the warmest day of 2022

Space Heating Network Losses

The heat losses from the space heating secondary circuit were calculated based on the number of and dimensions of risers, laterals, valves, and flanges within each building. Through site visits it was determined that the pipework is insulated with mineral wool with a thickness of 30 cm and a thermal conductivity of 0.037 W/mK. The internal temperature of the pipes is 75°C and the external ambient temperature was assumed to be 10°C. This results in a temperature difference of 65°C throughout the system. Based on these calculations the standing losses within the space heating system at Prescott House is 45.4 kW. Further information on these calculations are shown in Appendix 1: Energy Demand Assessment.

Overall Heat Losses

The existing 6-pipe secondary pipework system results in significantly higher heat losses than a 2-pipe system. The current standing losses within Prescott House are shown in Figure 5.

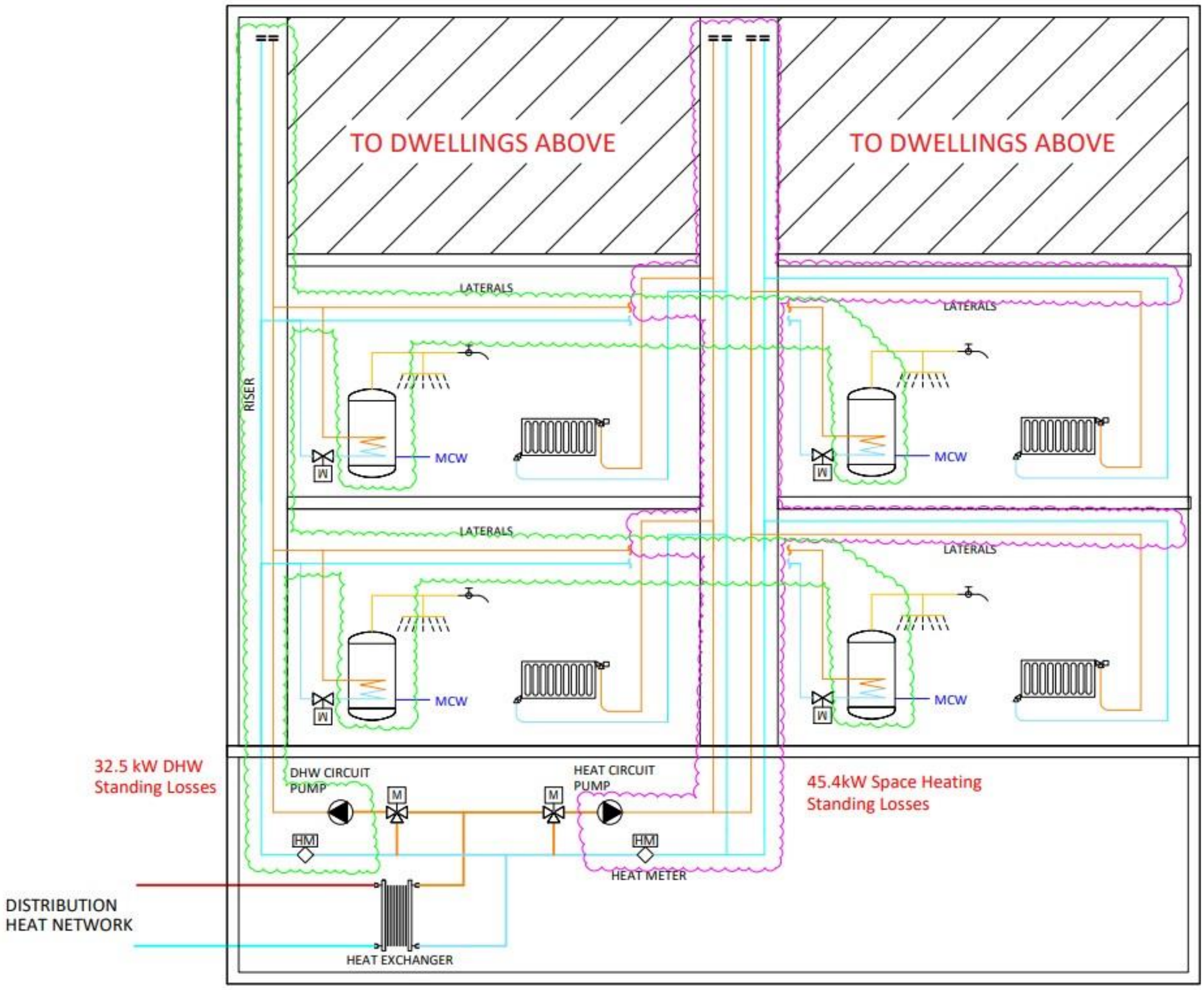

Figure 5: Secondary network losses in Prescott House

Figure 6 shows the average heat loss per dwelling for each of the housing blocks with data on the BMS. The losses range from approximately 900 W/dwelling in Napier to 1,100 W/dwelling in the tower blocks. Best practice for building losses is 100 W/dwelling. Therefore, a significant reduction in building heat losses is required to improve the overall network efficiency and reduce the estate's energy usage.

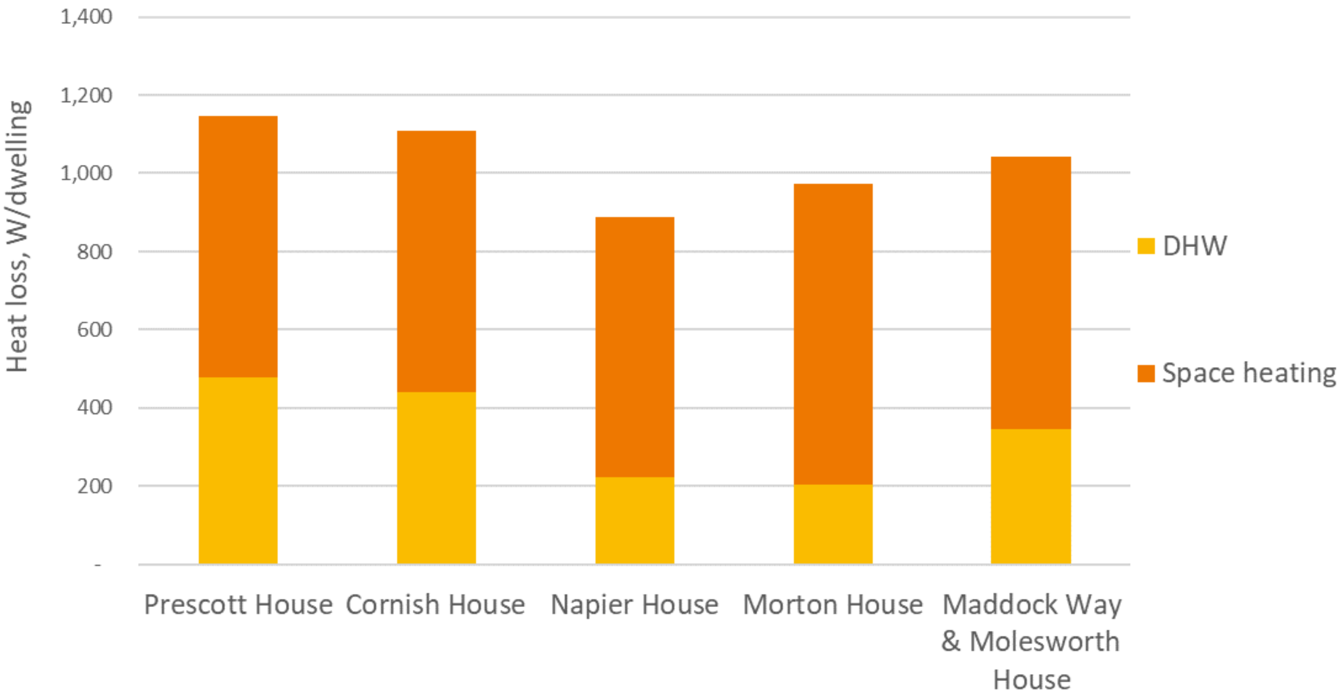

Figure 6: Average heat losses per dwelling in each building

To reduce the secondary and tertiary side losses and help achieve lower network return temperatures, it is proposed that all dwellings will receive heating system upgrades including HIUs, new radiators and copper pipework. The risers and laterals will be reconfigured with only the existing DHW pipework maintained, while all space heating secondary pipework is decommissioned, as shown in Figure 7. It has been estimated that these building upgrades will result in a decrease in secondary losses to 300 W/dwelling. It is also proposed that in the medium term, the secondary network is replaced which will further decrease the losses to the best practice target of 100 W/dwelling.

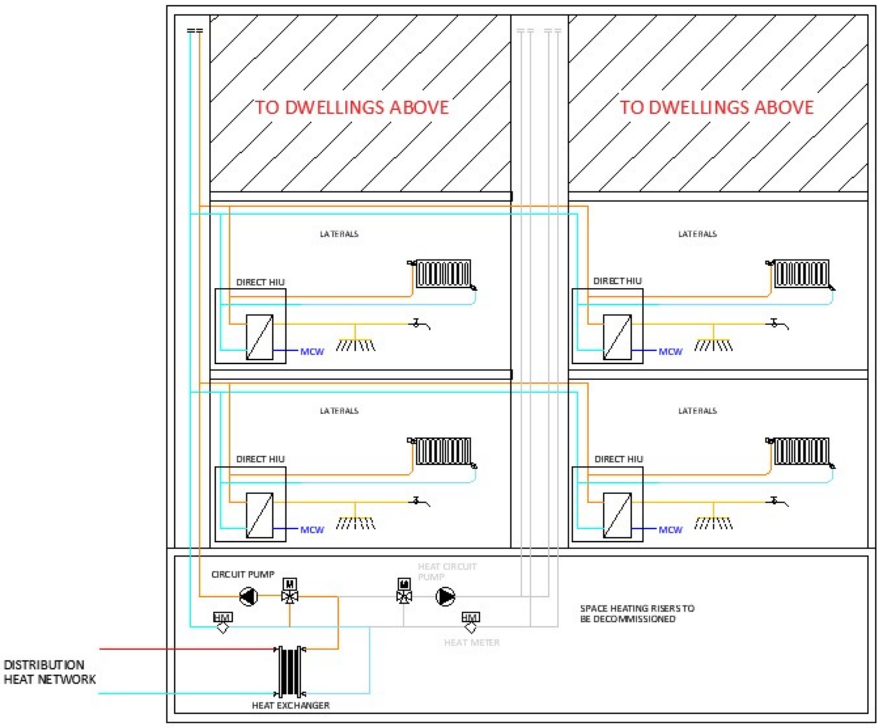

Figure 7: Proposed changes to risers and laterals from 6-pipe to 2-pipe system

3.2.2 Heat Demands

Following the identification of the building heat losses, the heat demands from the network connections were identified and are shown in Table 6.

Table 6: Heat demands from network connections

	Heat demand, kWh	Heat demand per dwelling, kWh
Bateman House	667,323	9,814
Brawne House	667,323	9,814
Cooks Road	33,346	11,115
Cornish House	595,309	8,755
Cruden House	595,309	8,755
Maddock Way and Molesworth House	753,829	10,470
Morton House	408,919	10,485
Napier House	217,510	6,042
Prescott House	667,323	9,814
Walters House	595,309	8,755
Brandon Library	103,150	N/A
Jack Hobbs Community Centre	109,555	N/A

The total annual network heat demand is shown in Figure 8. The total heating demand for all identified demands within the assessment area is approximately 6.9 MWh and a peak of approximately 2 MW. This drops to 5.9 MWh when the risers and laterals are replaced.

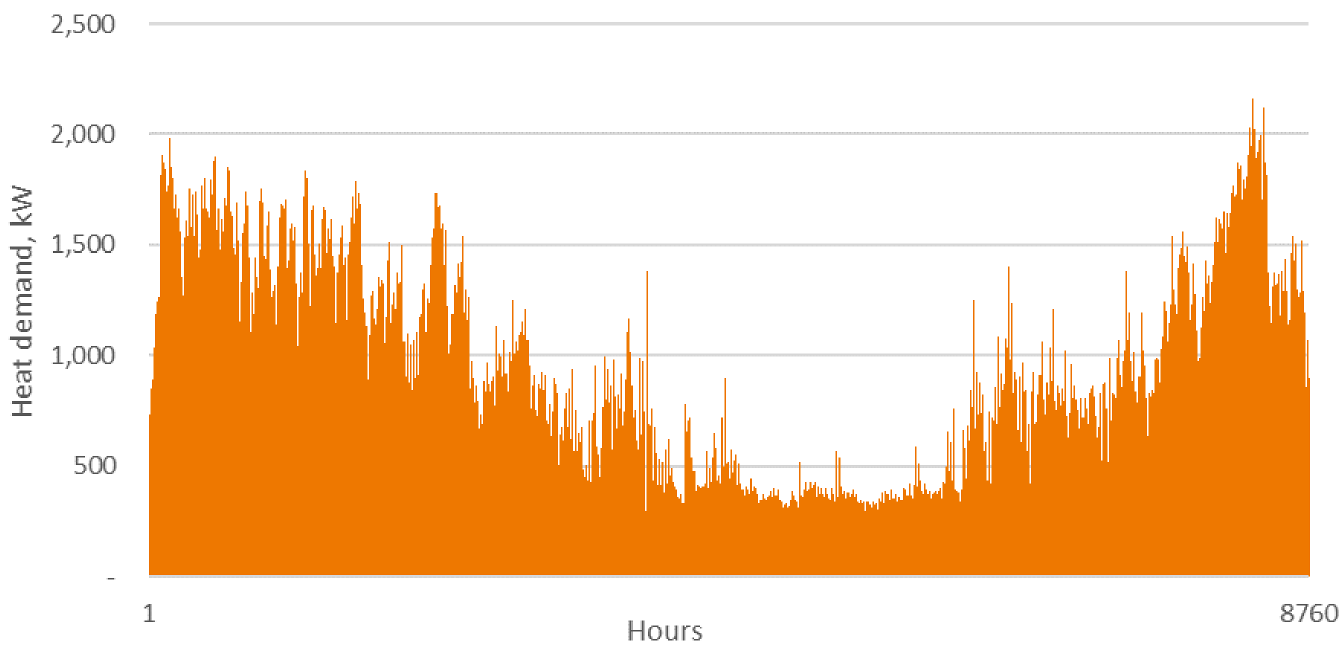

Figure 8: Total network annual demand

3.3 Summary

The existing network has extremely high heat losses within the secondary networks. This is primarily due to a 6-pipe riser and lateral system. It is proposed that this is reconfigured to a 2-pipe system alongside dwelling heating system upgrades. In future it is proposed that the existing risers and laterals are replaced which will further reduce the system losses.

The total network heat demand is approximately 7 MWh with a peak of 2 MW.

4 RECOMMENDED SCHEME OPTIONS ASSESSMENT

4.1 Energy Centre Location and Network Route

The proposed scheme will utilise the existing energy centre at Brandon Boiler House and the existing heat network pipes, as shown in Figure 9. There is sufficient space in the existing energy centre to incorporate new generation plant and associated equipment.

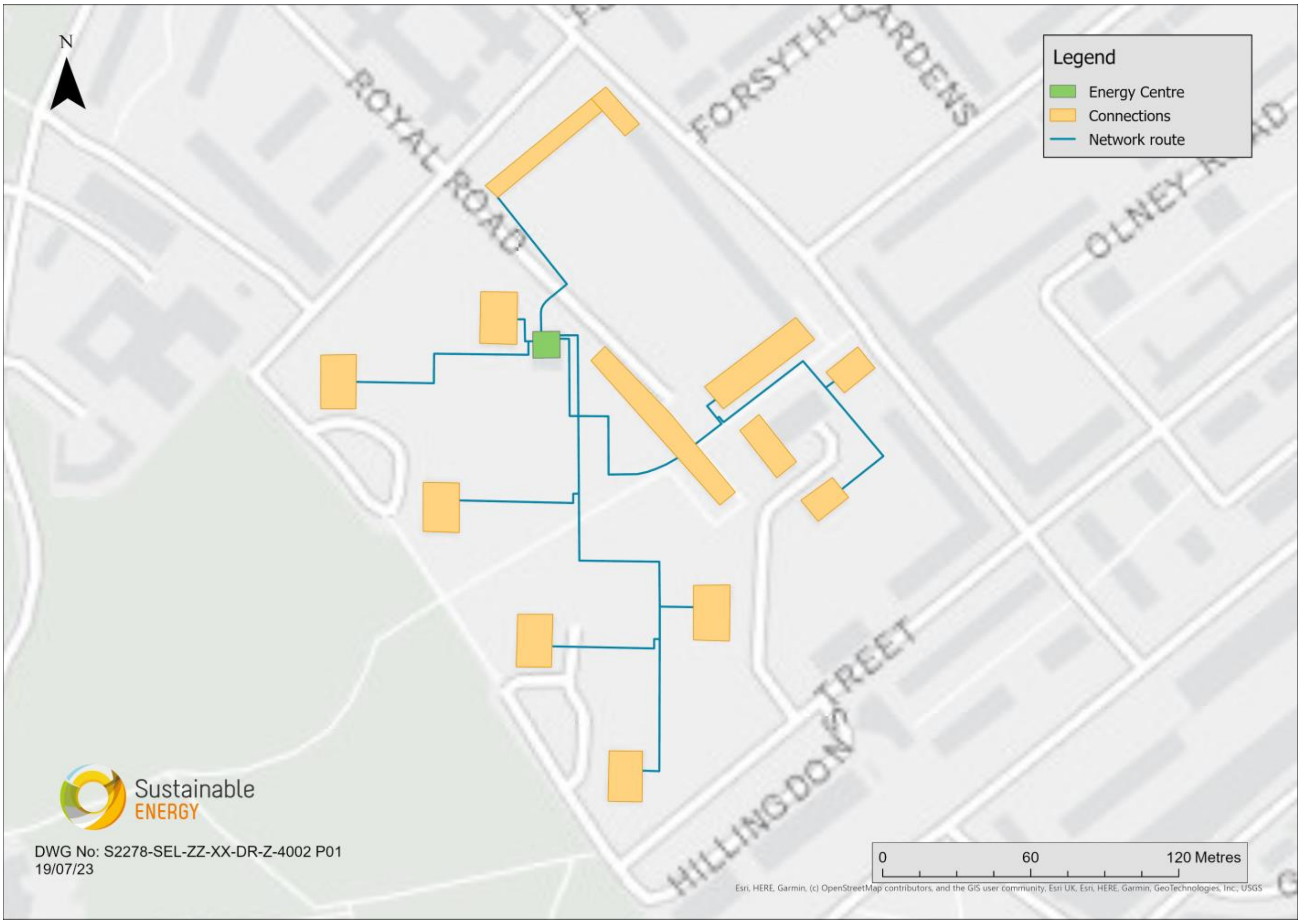

Figure 9: Existing network

4.2 Potential Heat Sources

Potential low carbon or renewable energy sources that are within or near the network assessment area were assessed to identify any energy sources that may have potential to supply a heat network. The options considered are discussed in section 4.2.1.

4.2.1 Long List Options

A long list appraisal of all potential low carbon heat sources to supply the network was undertaken and is shown in Table 7.

Table 7: Long list options appraisal for potential heat sources

Technology		High level technical viability considerations	Considered further?
Open loop	Ground source heat pump (GSHP)	• Yields from nearby LBS housing estates reach 19.5 l/s • Ground temperatures at nearby estates are a constant ~14°C throughout the year, leading to consistent heat pump efficiencies	Yes

Technology		High level technical viability considerations	Considered further?
heat pump		• Sufficient space within the estate for boreholes and interconnecting pipework • Higher CAPEX than ASHPs due to abstraction and discharge infrastructure	
	Mine water source heat pump (WSHP)	• No previous mine workings in the assessment area	No
	WSHP utilising sewer	• Complex commercial arrangements • Sewer flow rate can be variable, so may not be suitable to provide baseload • Third-party negotiations that may impact the cost of heat required	No
Closed loop GSHP		• Land space required for closed loop boreholes is available on the site • High number of holes will mean significant drilling and interconnecting pipes and manifolds would be needed to supply the ambient network • Ambient loop will operate at a low difference between flow and return Drilling across the green space outside of the towers will be disruptive for the local community (open loop solution will cause less disruption) • Borefield CAPEX is higher than the open loop solution and therefore the open loop is taken forward as the preferred solution	No
Deep geothermal		• Southwark has a relatively low geothermal potential of rock (approximately 50-60 MW/m^2) • Ground temperature at 1 km depth is <30 °C • Significant risk posed by very hot fluids at high pressure, which are difficult to control while drilling geothermal wells	No
Gas CHP		• Higher carbon emissions compared to other technologies • Electricity generation can reduce requirement for electricity import • Electricity from gas CHP lower CO_2e than the grid in earlier years	Yes
Waste heat offtake		• Complex commercial arrangements • No waste heat source identified near Brandon Estate • Changing public perception of EfW as 'green' technology option	No
ASHP		• Lower initial CAPEX than GSHP, however higher operating costs due to lower CoP • ASHPs on the roof will require access for regular operations and maintenance • Will have noise impact which if at ground level will potentially impact on nearby sites or will require large acoustic enclosure • ASHP at large scale may have cold plume and cooling effect on local environment	No
Electric Boilers		• Expensive if used during peak electricity usage times • Possible price reduction /kWh in future	Yes, only as future peak and reserve
Gas Boilers		• High CO_2e • Potentially lower OPEX than electric boilers	Yes, only as peak and reserve
Biomass CHP/ Biomass boiler		• Lowest carbon in earlier years (better than heat pumps until predictions of grid decarbonisation) • Unlikely to be sufficient space due to larger space requirements compared to other heat sources because of solid fuel delivery and storage • May cause congestion / environmental impact due to frequency of fuel deliveries • Sustainability of biomass is dependent on the availability of a local, reliable source of fuel • Not economic against counterfactual scenarios (particularly without RHI)	No

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Technology	High level technical viability considerations	Considered further?
Hydrogen Fuel Cell CHP	• Economics of hydrogen-based CHP very uncertain as fuel cell market not developed • Security of fuel supply issues as no local hydrogen production and need to be transported by road • Requires significant space for fuel cell • Economic and regulatory issues relating to private wire	No
Solar thermal	• Significant initial capital costs • Significant land required for collector arrays	No

4.2.2 Short List Options

As a result of the long list assessment, three potentially technically viable solutions were shortlisted for further consideration. These technologies have the potential to meet the client's key priorities by providing affordable low carbon/renewable energy. A short list appraisal of each option was then undertaken that considers possible risks, benefits, and disbenefits of the selected options. The following options have been shortlisted:

- GSHP and gas CHP (Table 8)
- GSHP only (Table 9)
- Gas CHP only (Table 10)

Table 8: Specific issues, risks, benefits, and disbenefits for GSHP and gas CHP solution

		Viability consideration	Risks	Benefits	Disbenefits	Prioritised solution?
GSHP and gas CHP	Technology selection	• Modular open loop heat pumps and small gas CHP • High CAPEX due to requirements for both gas CHP and GSHP technology	Long term performance of boreholes	Multiple technologies increases resilience		Yes
	Heat resource	• Ground temperatures at other LBS estates suggest a constant temperature of ~14°C available at Brandon • Environment Agency (EA) have previously consented to an abstraction flow rate limit of 19.5 l/s at all other LBS estates	Availability of heat in the ground	If correctly designed and modelled, temperature of heat resource likely to be stable and sustainable	Dependent on accessing ground water	
	Plant operation	• Small gas CHP will meet the electricity requirements of one of the heat pump units to reduce scheme OPEX • The other heat pump will operate when the network demand exceeds the generation capacity of the CHP and first heat pump		~90% of network heat demand will be from renewable technology Lower CO_2e intensity than GSHP only solution initially due to lower CO_2e electricity from the gas CHP	CO_2e intensity of the network will increase over time as the grid decarbonises	
	Energy centre design	• Existing energy centre has sufficient space for technologies • New flue for gas CHP would be required • External thermal store required which could have visual impact	External thermal store could have visual impact	Plant can be installed in existing energy centre		
	Impact on Brandon Estate	• A number of boreholes would be drilled in the green space near energy centre • Flue dilution may be required due to air quality impacts from gas CHP	Public opposition to drilling in park could delay process		Potential flue dilution may result in additional CAPEX requirements	

Table 9: Specific issues, risks, benefits, and disbenefits for GSHP only solution

		Viability consideration	Risks	Benefits	Disbenefits	Prioritised solution?
GSHP only	Technology selection	• Modular open loop heat pumps • Additional borehole may be required to meet full site heat demand	Long term performance of boreholes	Modular heat pumps increases scheme resilience		No
	Heat resource	• Ground temperatures at other LBS estates suggest a constant temperature of ~14°C available at Brandon • EA have previously consented to an abstraction flow rate limit of 19.5 l/s at all other LBS estates	Availability of heat in the ground	If correctly designed and modelled, temperature of heat resource likely to be stable and sustainable	Dependent on accessing ground water	
	Plant operation	• Heat generated from the GSHP will be prioritised with gas boilers only supplying peak demands and in times of maintenance / failure • All electricity demand will be imported from the grid	High energy centre electricity price could affect scheme viability	~90% of network heat demand will be from renewable technology Lowest long term CO_2e intensity option	Highest OPEX option	
	Energy centre design	• Existing energy centre has sufficient space for technologies • External thermal store required which could have visual impact	External thermal store could have visual impact	Plant can be installed in existing energy centre		
	Impact on Brandon Estate	• A number of boreholes would be drilled in the green space near energy centre	Public opposition to drilling in park could delay process			

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Table 10: Specific issues, risks, benefits, and disbenefits for gas CHP only solution

	Viability consideration		Risks	Benefits	Disbenefits	Prioritised solution?
Gas CHP only	Technology selection	• Gas CHP unit • Potentially lowest CAPEX option	Long term performance of boreholes		Not eligible for grant funding	No
	Heat resource	• Heat generated at higher temperatures that are suitable for existing buildings • Dependent on gas supplies	Availability and price of gas resources		Lowest energy security option	
	Plant operation	• Heat generated from the gas CHP will be prioritised with gas boilers only supplying peak demands and in times of maintenance / failure	High energy centre gas price could affect scheme viability	~90% of network heat demand will be from low carbon technology Lowest OPEX option	Highest long term CO_2e intensity option	
	Energy centre design	• Existing energy centre has sufficient space for technologies • New flue for gas CHP would be required • External thermal store required which could have visual impact	External thermal store could have visual impact	Plant can be installed in existing energy centre		
	Impact on Brandon Estate	• Flue dilution may be required due to air quality impacts from gas CHP • Emissions abatement equipment would also be required due to larger gas CHP engine		Drilling of boreholes in nearby park not required	Flue dilution and emissions abatement plant will result in additional CAPEX requirements	

4.3 Summary

A prioritised heat generation solution of modular GSHPs and a small gas CHP unit has been identified for the Brandon Estate. This solution will minimise energy centre OPEX through the supply of electricity from the gas CHP to one of the GSHPs and reduce the risk relating to highly volatile energy prices. The proposed scheme will also maximise the CO_2e savings in the short term as the CO_2e intensity of electricity generated from the gas CHP is lower than the grid. However, as the grid continues to decarbonise, minimising the electricity generated from the gas CHP will result in greater CO_2e savings. Therefore, it is proposed that the gas CHP is removed from the energy centre once it reaches its end of life (15 years) to allow a greater proportion of heat to be met by the GSHPs. The proposed solution is flexible with the potential for an additional GSHP to be installed in the future, should this be beneficial due to energy prices and CO_2e intensity.

The scheme will utilise the existing energy centre building and primary, buried network. However, to increase the efficiency of the network and reduce losses, upgrades to the heating systems within dwellings will be required. This will consist of the installation of HIUs, new radiators and copper pipework throughout the dwelling. The 6-pipe secondary side riser and lateral system throughout the estate will also be reconfigured with the 4-pipe space heating circuit disconnected leaving only 2 DHW pipes in operation. This will significantly reduce the losses in the network in the short term, however, it is recommended that these are replaced in the medium term to further increase network efficiency in line with best practice.

The three phases proposed for the scheme are:

- Phase 1: GSHP and gas CHP installed alongside upgrades to commercial and dwelling heating systems
- Phase 2: Risers and laterals within housing blocks are replaced
- Phase 3: Gas CHP is removed at the end of its lifetime

5 CONCEPT DESIGN

This chapter describes the scheme concept design and includes details of the primary heat sources, peak and reserve boilers, other energy centre equipment, utilities connection requirements and metering.

5.1 Futureproofing

Futureproofing measures have been considered throughout the concept design process for the network options. There is sufficient capacity in the energy centre design to accommodate future low carbon plant, including an additional GSHP.

5.2 Brandon Estate Energy Centre

The energy centre includes GSHPs, gas CHP, peak and reserve gas boilers, thermal storage tanks and provision for auxiliary equipment. The heat pump and gas CHP sizing and installation has been developed to maintain a low carbon intensity (kg/CO_2e) and provide ~90% of network demand. Two of the existing gas boilers will remain in the energy centre and used as an auxiliary source for peak supply, or as a reserve heat source for periods of heat pump or abstraction maintenance or failure. Controls will prioritise heat from the heat pump and gas CHP. A summary of plant capacities is shown in Table 11.

Table 11: Brandon Estate energy centre summary

	Phase 1	Phase 2	Phase 3
GSHP capacity	1,000 kW		
Gas CHP capacity	200 kWe/ 252 kWth		-
Peak and reserve boiler capacity	4,600 kW		
Thermal store capacity	50,000 litres		
Energy centre footprint	220 m^2		
% Low carbon heat	92%	94%	87%
Year 1 carbon intensity kgCO_2e/kWh	0.76		

The CO_2e intensity of the network shown in Figure 10, is lower than a GSHP only scheme for the first few years of operation as the CO_2e intensity of electricity generated from the gas CHP is lower than the electricity mix of the grid. However, as the grid continues to decarbonise the network CO_2e intensity increases until phase 2 when the secondary side upgrades are installed and the network demand decreases. The CO_2e intensity of the network reduces further in phase 3 when the gas CHP is removed.

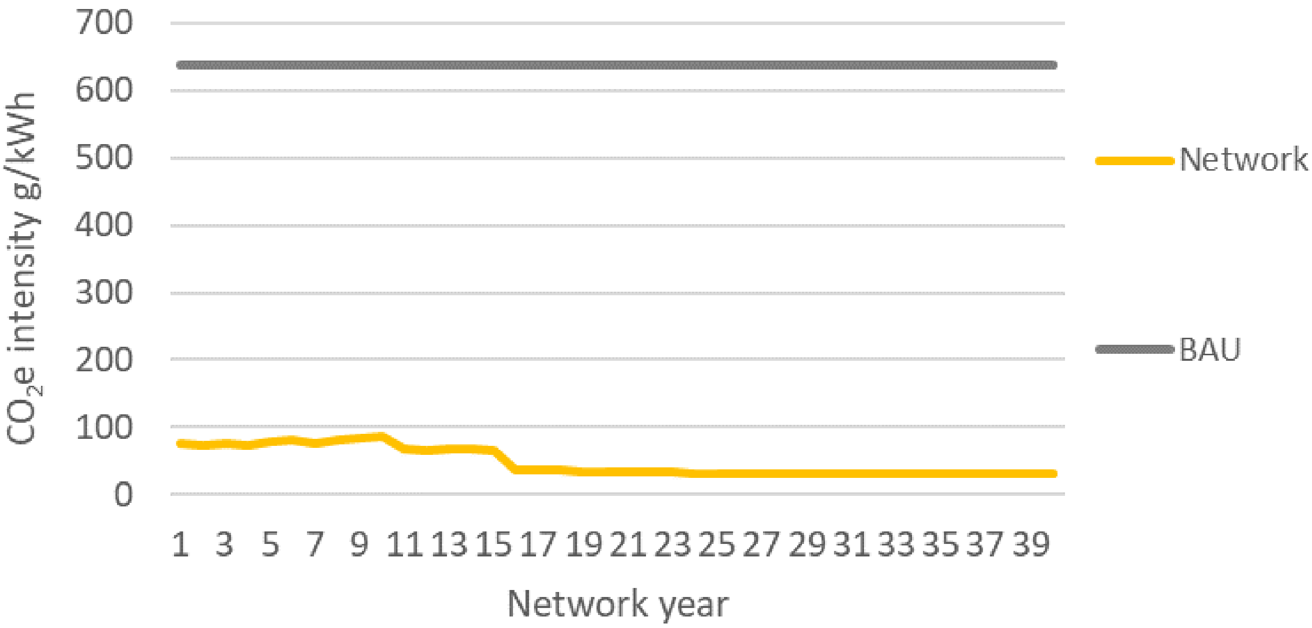

Figure 10: Annual network CO_2e intensity

5.3 Energy Centre Footprint

The energy centre space at Brandon is approximately 220 m^2 with a varying height between 4-7 m. The existing energy centre has sufficient space for the plant and equipment for the proposed new solution. A general arrangement for the energy centre is shown in Figure 11 (drawing no. S2278-SEL-EC-00-DR-Y-0001). The arrangement includes consideration of the installation, operation, maintenance, and decommissioning of key plant items.

Process flow diagrams (PFDs) outlining the key functionality of the heating system for the phase 1 network is shown in Figure 12 (drawing no. S2278-SEL-EC-XX-DR-Y-6001).

Figure 11: Energy centre general arrangement – phase 1

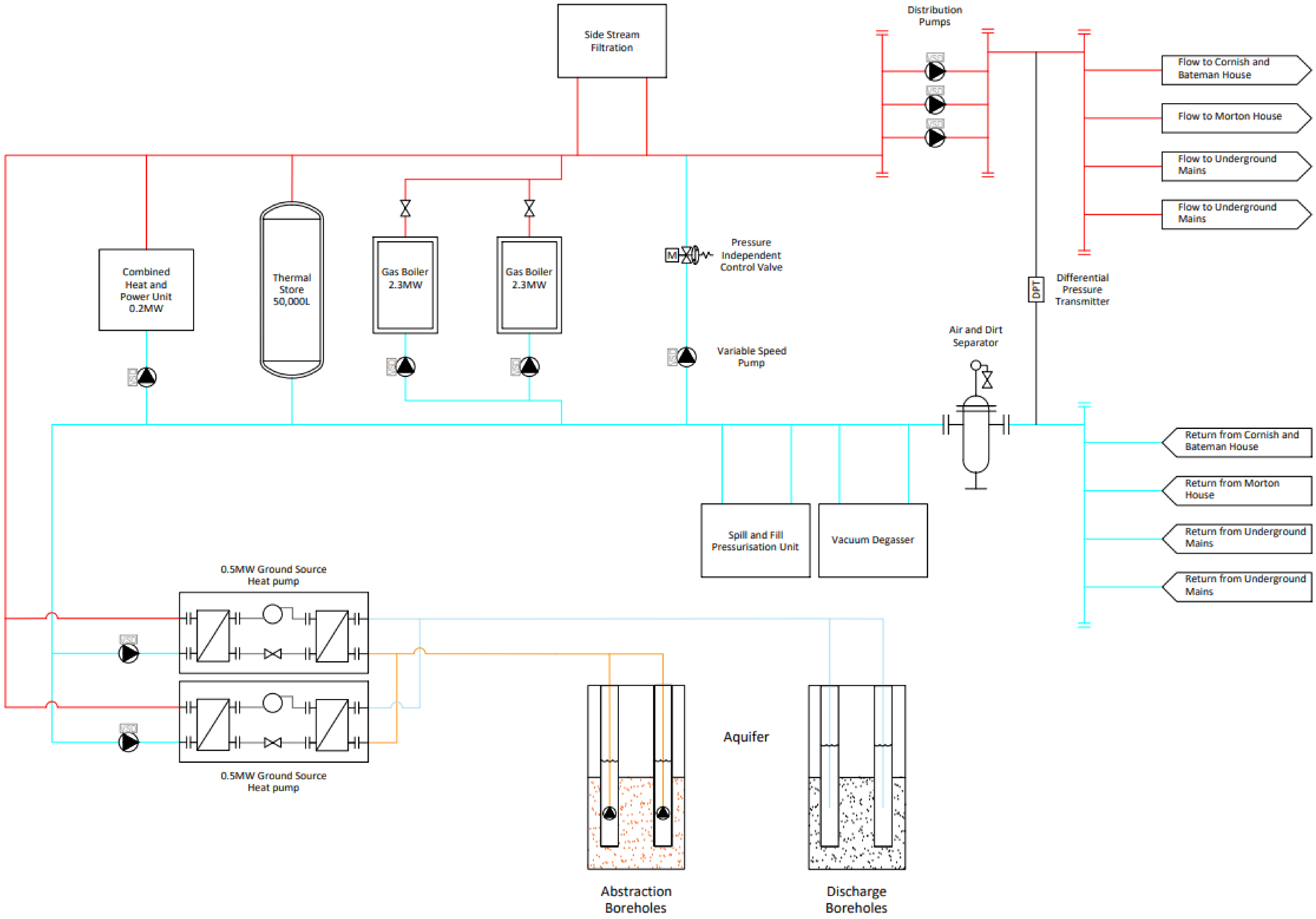

Figure 12: Energy centre PFD – phase 1

5.4 Technology Sizing

5.4.1 GSHPs

The GSHPs will be packaged units connected to two main circuits: the ground water abstraction circuit and the primary heating circuit. The ground water circuit operates by running a low-temperature, low pressure refrigerant fluid through a heat exchanger to extract heat from the ground water that has been pumped to the energy centre.

The refrigerant fluid 'absorbs' the heat and boils at low temperature with the resulting gas being compressed to increase the temperature, the gas is then passed through another heat exchanger, where it condenses, releasing its latent heat to the primary heating circuit.

The heat pump refrigerant circuit will be hermetically sealed and subject to the F-gas directive and the working fluid will be a Low Global Warming Potential refrigerant.

The heat pump capacity will be sized based on the network demand and the ground water resource. Consideration has also been given to the optimum balance between heat generation capacity, capital cost, maintenance costs and physical size.

The heat pump sizing strategy will include 2no. 500 kW, modular heat pumps rather than a single 1,000 kW heat pump to ensure the heat pumps can moderate generation in line with lower network demands in the summer. This sizing strategy also allows the additional flexibility in operation of the scheme in periods of scheduled maintenance and resilience in the event of heat pump failure.

Borehole Locations

Figure 13 shows locations of the GSHP abstraction and discharge boreholes. Two abstraction boreholes will be required with a spacing of 20 m. The two discharge boreholes must be located at least 150 m from the abstraction boreholes to ensure that the lower temperature discharged water does not feed back and impact the abstracted water. The boreholes will be drilled to a depth of 130 m, based on that of Wyndham Estate.

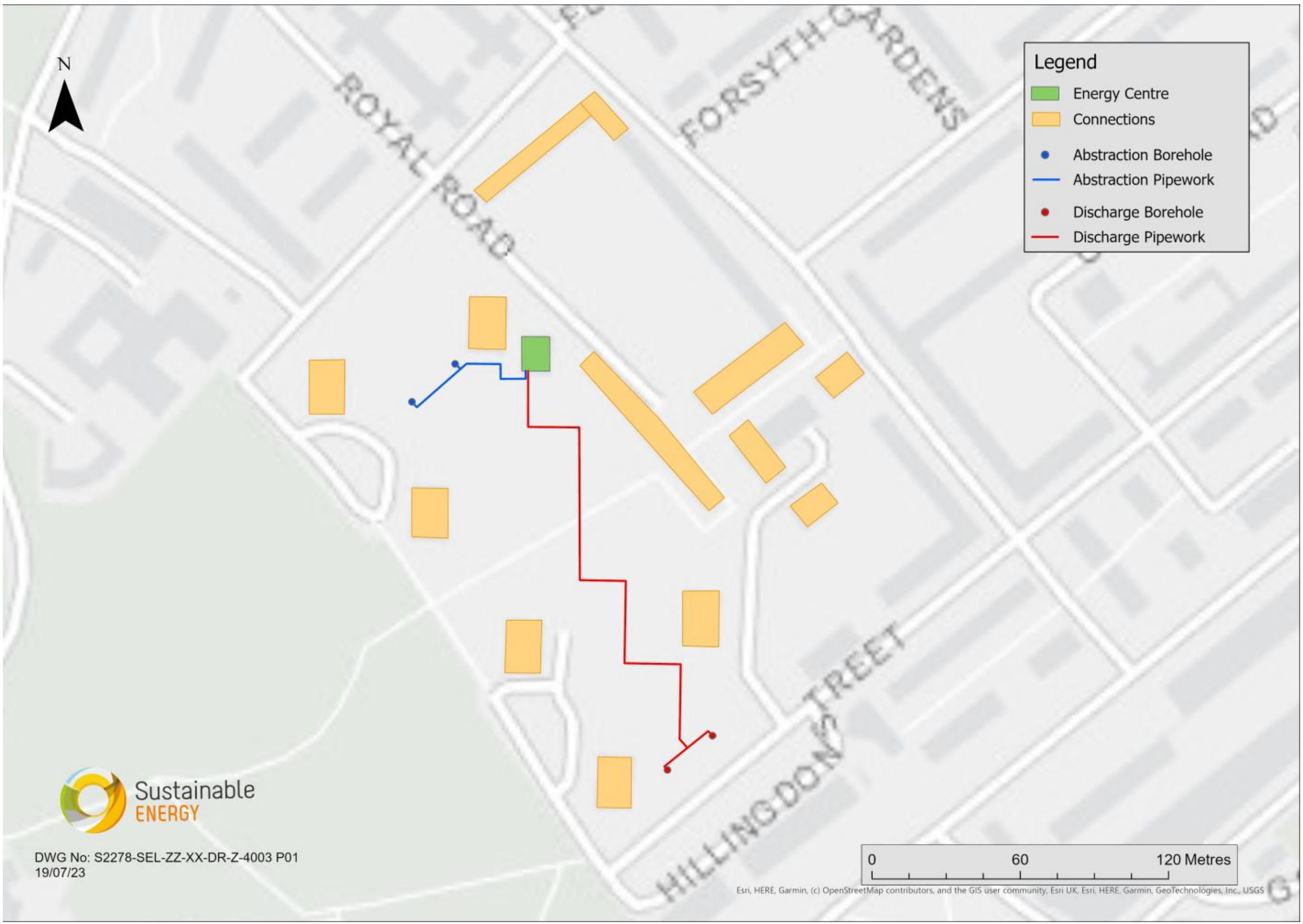

Figure 13: Abstraction and discharge borehole locations

Well Heads

The well head should include pipe work connections and a manifold to connect to the submersible pumps and the riser pipe to the buried pipe that connects the energy centre. The borehole well heads will incorporate a framework to allow retraction of the submersible pumps. The chamber will incorporate a lockable walk over steel cover that can be raised to access the borehole. The cover should be hinged and torsion spring assisted to comply with HSE manual handling and suitable for one person operation. The cover should be manufactured in mild steel plate and hot dip galvanised. It should have lever down locking with a shrouded locking padlock (facilities and be secure to (LPCB) Security Level 3). Hinges should be hidden to protect against the ingress of grit.

5.4.2 Gas CHP

The proposed gas CHP engine is a reciprocating, spark ignition gas engine fitted with exhaust gas heat exchangers. The engine is directly coupled to a synchronous electricity generator, co-producing heat (from the exhaust gas heat exchanger and engine cooling circuits) and electrical power (from the generator). The unit will be a packaged plant item which includes a noise reducing canopy enclosing the engine, generator, heat exchangers, and ancillary equipment.

The gas CHP unit will be a small 200 kWe / 252 kWth engine that has been sized to meet the electricity demand of one of the 500 kW GSHP units. This will minimise the cost of electricity import for the scheme while maximising the low carbon heat produced from the GSHPs.

5.4.3 Future Phases

The proposed scheme is a flexible solution that can include a number of technology options in future, depending on what the market and grid conditions are at that time. Based on current carbon and price projections it is proposed that the gas CHP is removed at the end of its lifetime in 15 years. This could be replaced by an additional GSHP or by another gas CHP in future. However, at the time of writing the most viable economic and carbon solution is for the existing GSHPs and gas boilers to increase their output to meet the shortfall in generation.

5.4.4 Peak and Reserve Boilers

Two of the existing 2.3 MW gas boilers at Brandon energy centre will remain as peak and reserve heat sources for the scheme. The boilers meet an n+1 methodology that ensure that the full heat demand can be met if one of the boilers is not operational. The boiler peak assumes that the heat pumps and gas CHP will not be operational. This will provide redundancy and allow boilers to operate at their highest efficiency throughout the range.

5.4.5 Thermal Storage

Thermal storage has been included to maximise the proportion of heat that can be provided from the GSHPs and reduce the use of the peak and reserve boilers. The thermal storage comprises large cylindrical, insulated water tanks which will be connected in series with each other to maximise the stratification of the stored volume. The thermal storage will be connected in parallel with the low carbon plant so that a proportion of heat is always used to charge the thermal stores when they are below full capacity. The network will utilise a 50,000 litre thermal stores of circa 3.6 m diameter and 5 m height.

5.4.6 Flues

The design of the gas CHP flue needs to achieve sufficient velocity of exhaust gas to achieve adequate dispersion, avoiding concentrations of harmful gasses such as nitrogen oxides (NOx). The effects of wind loading and structural requirements of the flues must also be assessed and incorporated into the structural design of the energy centre. The small gas CHP will be a low Nox version therefore the impact on the air quality of the area will be reduced,

The existing gas boilers will continue to utilise the existing flue that runs through to Consort House.

5.4.7 Operating Conditions

A detailed assessment of the proposed network has been undertaken and the proposed operating conditions reflect the optimal network efficiency. To ensure heat network losses are kept below 10%[3], and to effectively serve a combination of new build developments and existing buildings with varying secondary systems, the heat network will need to operate variable temperature conditions.

Primary Network Temperatures

The primary heat network will provide heat via plate heat exchangers which means the flow temperature on the primary network into each building will be slightly higher at circa 70°C at peak conditions and 65°C flow temperature for summer conditions.

The energy generating plant in the energy centre will be made up of various technologies that have different temperature conditions that affect the efficiency of each technology (i.e. gas boilers, CHP and heat pump). Gas boilers can operate at higher temperatures of 90°C without impacting negatively on efficiency. Heat pumps, however, have a performance which is

[3] The CIBSE/ADE HNCoP states that the calculated annual heat loss from the network up to the point of connection to each building when fully built out is typically expected to be less than 10 %

significantly impacted by the temperature conditions of the network and, to maintain effective performance, network flow and return temperatures should be as low as possible.

Controlled scheduling of heat pumps and gas boilers will be required to maintain an overall efficiency of each technology. Heat pumps will not be used to supply higher temperature peak demands, so the higher temperatures required for peak demands will be supplied by gas boilers. However, when temperatures and loads are lower (e.g. summer conditions), the heat pump will supply higher levels of demand. Detailed modelling has been carried out to consider varying demand profiles, temperature conditions and carbon impacts.

Secondary System Temperatures

The proposed network comprises mainly of existing housing blocks. The existing buildings are currently operating at flow temperatures within a range of 75°C flow and return temperatures of 65°C. The dwellings will require heating system upgrades including HIUs, new radiators and copper pipework to achieve lower network return temperatures. The target secondary side temperatures are 65 °C flow and 40 °C return. If buildings operate at higher temperatures, then supply temperature from the heat pump needs to be higher, this has a negative impact on the SPF of the heat pump. Upgrades to the building secondary pipework will be completed in phase 2, which will allow network temperatures and losses.

Operating Pressure

The primary system varies from 3 m to 7 m above sea level. Static pressure of circa ~1 barG in the existing boiler room and a differential pumping pressure of 1.5 bar gives a minimum network pressure of 1 bar at the Jack Hobbs Community Centre connection which is the furthest point on the network in hydraulic terms.

5.4.8 Variable Speed Pumps

The design utilises variable speed pumps in a multi-pump arrangement (3 pumps – 2no. duty and 1no. standby). They will be controlled to maintain a minimum pressure difference at specific locations using index differential pressure sensors within the network. The pump set will be sequenced, and speed controlled (on a demand basis) to maintain a differential pressure that is influenced by the pressure independent control valves controlling heat demand to ensure heat demands are satisfied and flow rates are minimised.

The benefits of the variable speed function will be realised as peak flow rate conditions will typically only occur for brief periods during a heating season, with average demands being much lower.

5.4.9 Ancillary Equipment

All balance of plant such as pressurisation, expansion and water treatment are designed with redundancy so that failure of any one item will not prevent the plant from generating and distributing heat to the network.

5.4.10 Utilities Connections

Electricity

An upgraded electricity connection will be required at the energy centre to meet the 500 kVA requirements for the site. A budget quote was requested from UK Power Networks (UKPN) but was not received at the time of writing. For this assessment a budget quote received by Buro Happold in the Pre-Feasibility Report (2021) of £113,000 + VAT from UKPN was used.

Gas

The existing gas connection at the energy centre will be sufficient to supply the proposed heating system

Water and Drainage

An existing mains water supply and drainage is available at the energy centre.

5.4.11 Metering

All metering should be specified with suitable accuracy class in accordance with the Measurement Instrumentation Directive to satisfy the utility requirements for the purchase and sale of heat, gas, water, and electricity for the energy centre.

Heat

The energy centre will have at least five heat meters installed: two heat pump heat meters, a CHP heat meter, a combined gas boiler heat meter and a combined export heat meter. The ultrasonic flow sensors measure flow and return temperatures and flow rates and the multi-function meters will calculate the heat energy exported. The heat meters will provide output signals (via Mbus) for instantaneous measurements and cumulative measure of flow and energy. Data from all meters will be imported into the control system and used for control and monitoring of system performance.

Water

There will be water meters to determine the cumulative use by each of the system pressurisation units, water treatment plant and the overall incoming mains water to each of the energy centres. All data will be collected by the control system.

Electricity

Electricity meters will be fitted to measure the supply to the heat pumps, the generation from the gas CHP and the import electricity from the grid.

5.5 Building Connections

Dwellings

All dwellings will be fitted with an HIU, new radiators and copper pipework to reduce network return temperatures. The general arrangement of a dwelling in Bateman House is shown in Figure 14.

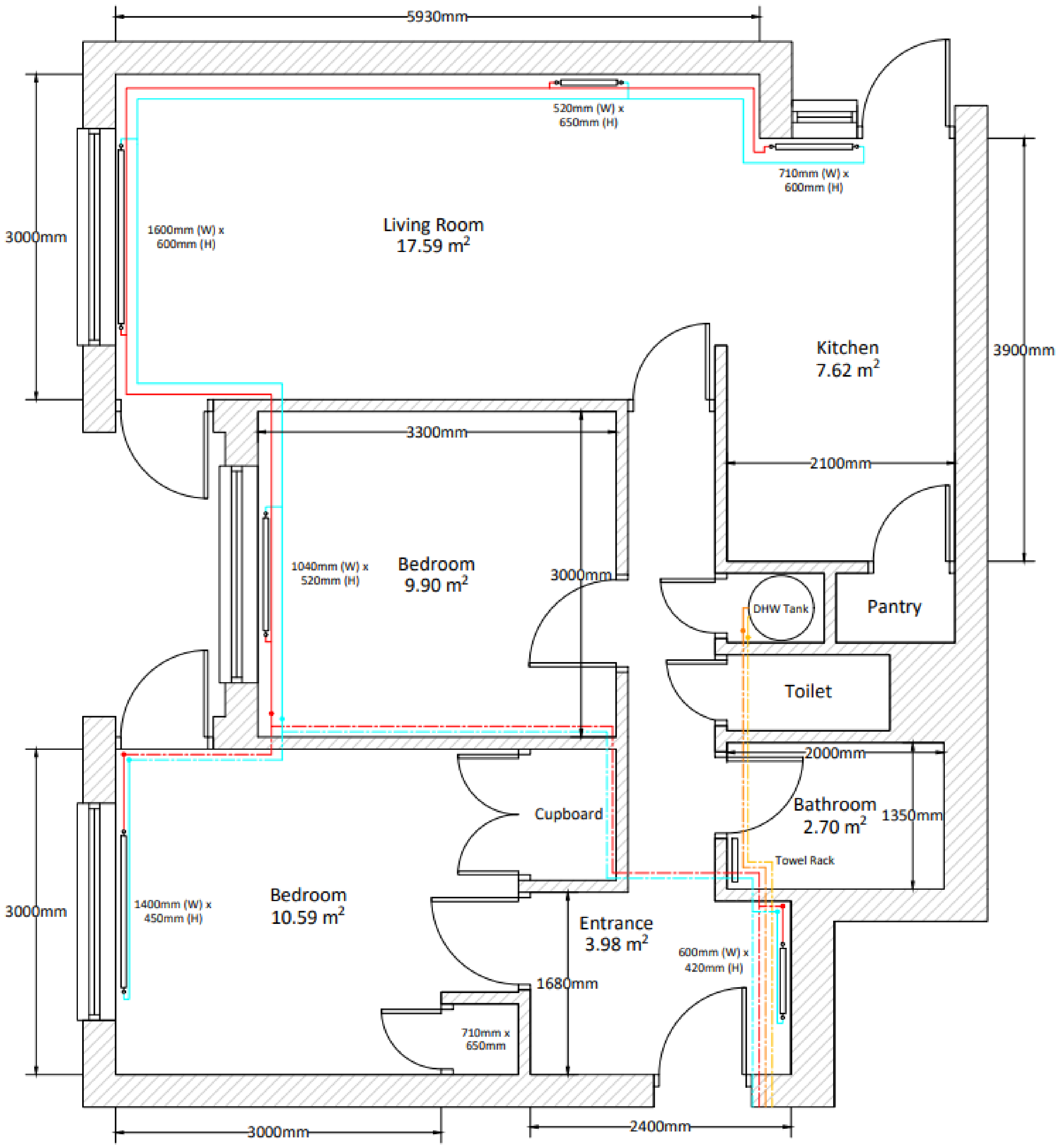

Figure 14: Dwelling general arrangement – Bateman House

All dwelling connections will be indirect (where a heat exchanger separates the heat network hydraulically from the building space heating and hot water systems). This will predominantly be through a substation at building entry with direct HIUs installed in the dwellings (see Figure 15, drawing no. S2278-SEL-FP-XX-DR-Y-7001). However, Cooks Road and Napier House do not have existing substations and therefore indirect HIUs will be installed in these dwellings as shown in Figure 16 (drawing no. S2278-SEL-FP-XX-DR-Y-7002).

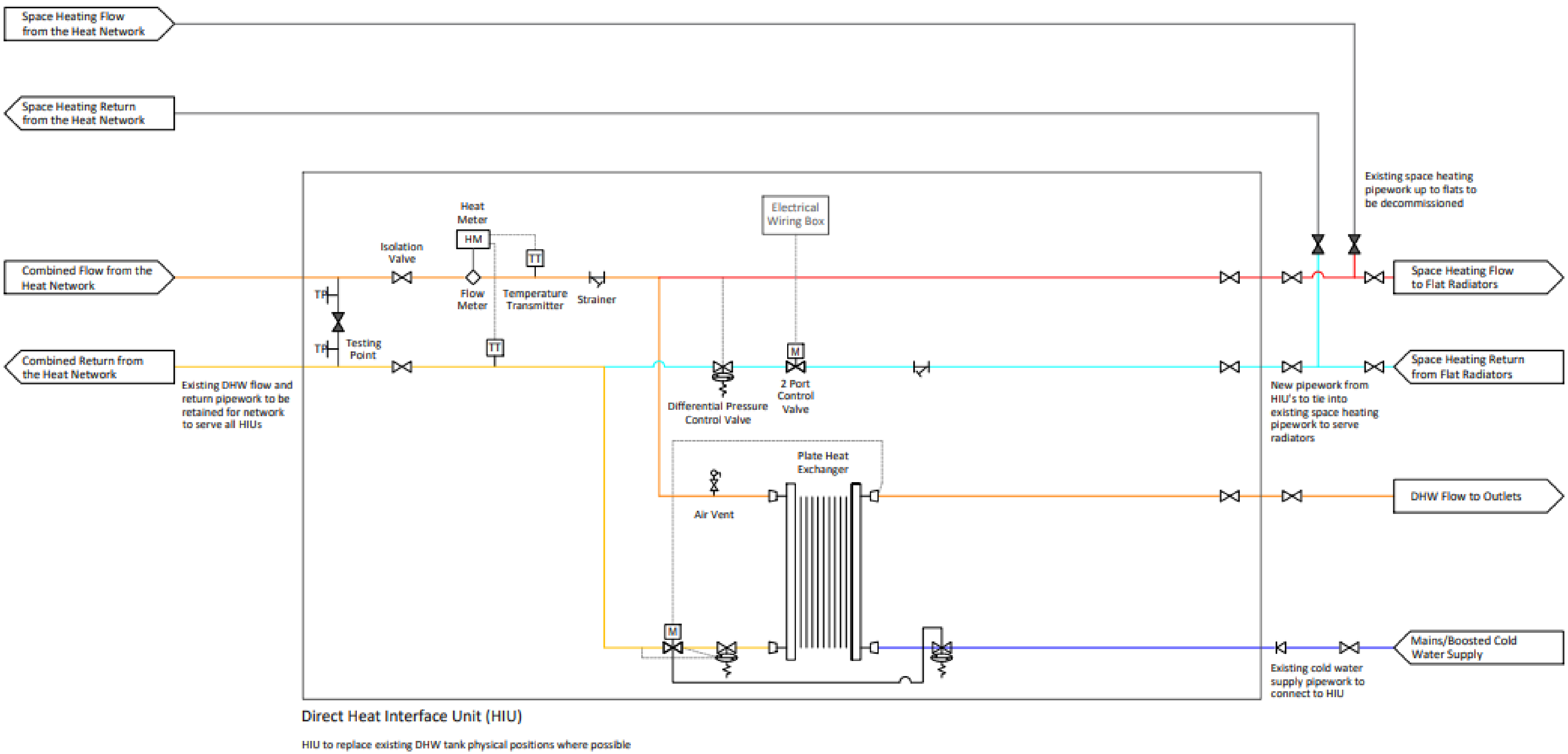

Figure 15: Dwelling with direct HIU connection

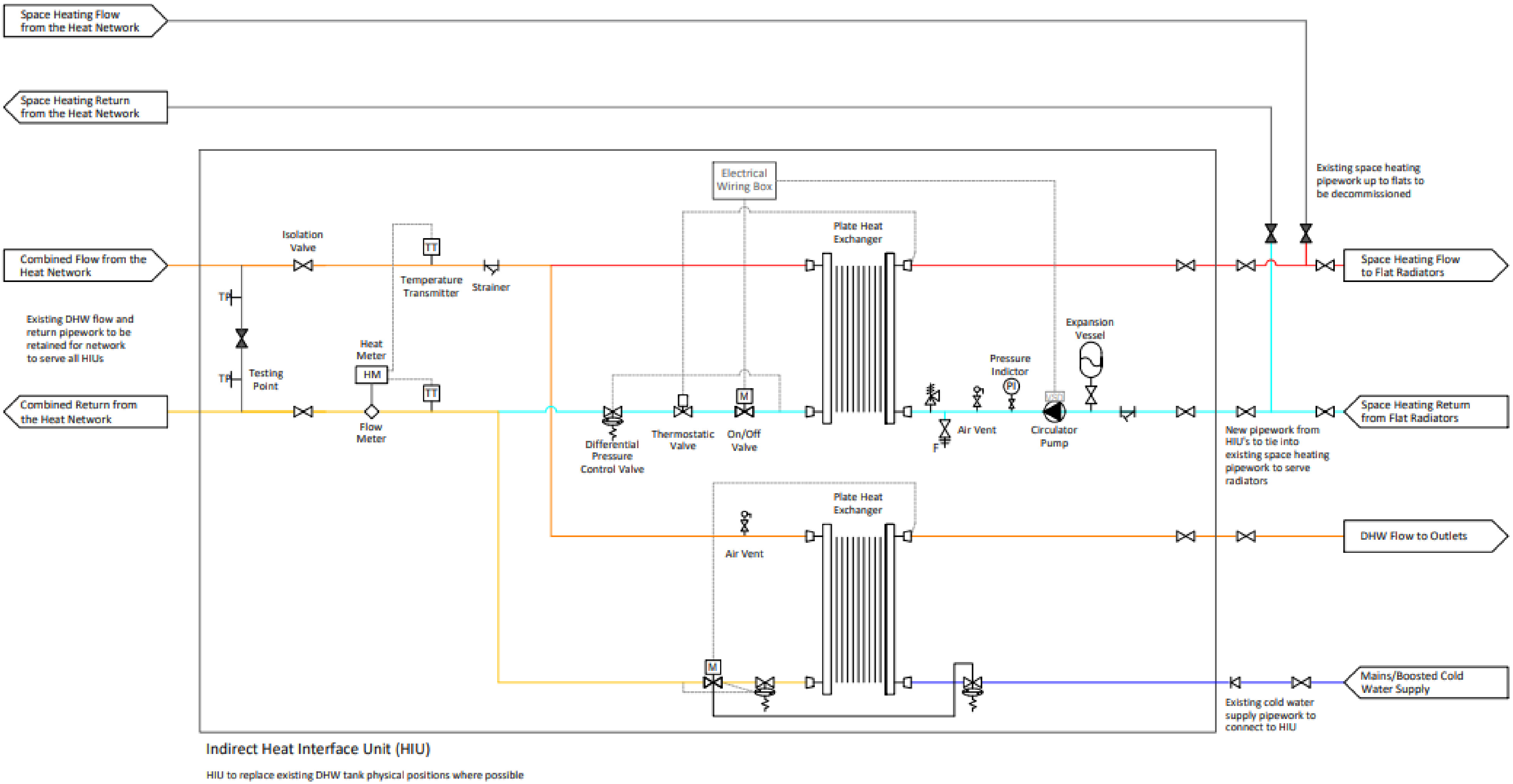

Figure 16: Dwelling with indirect HIU connection

Housing Blocks

The 6-pipe secondary pipework system will be reconfigured in phase 1, with the 4-pipe space heating circuit decommissioned and the 2-pipe DHW circuit supplying both the dwellings' hot water and space heating demand as shown in Figure 17. In phase 2, these risers and laterals will be replaced with new pipework which will allow a reduction in losses and return temperatures.

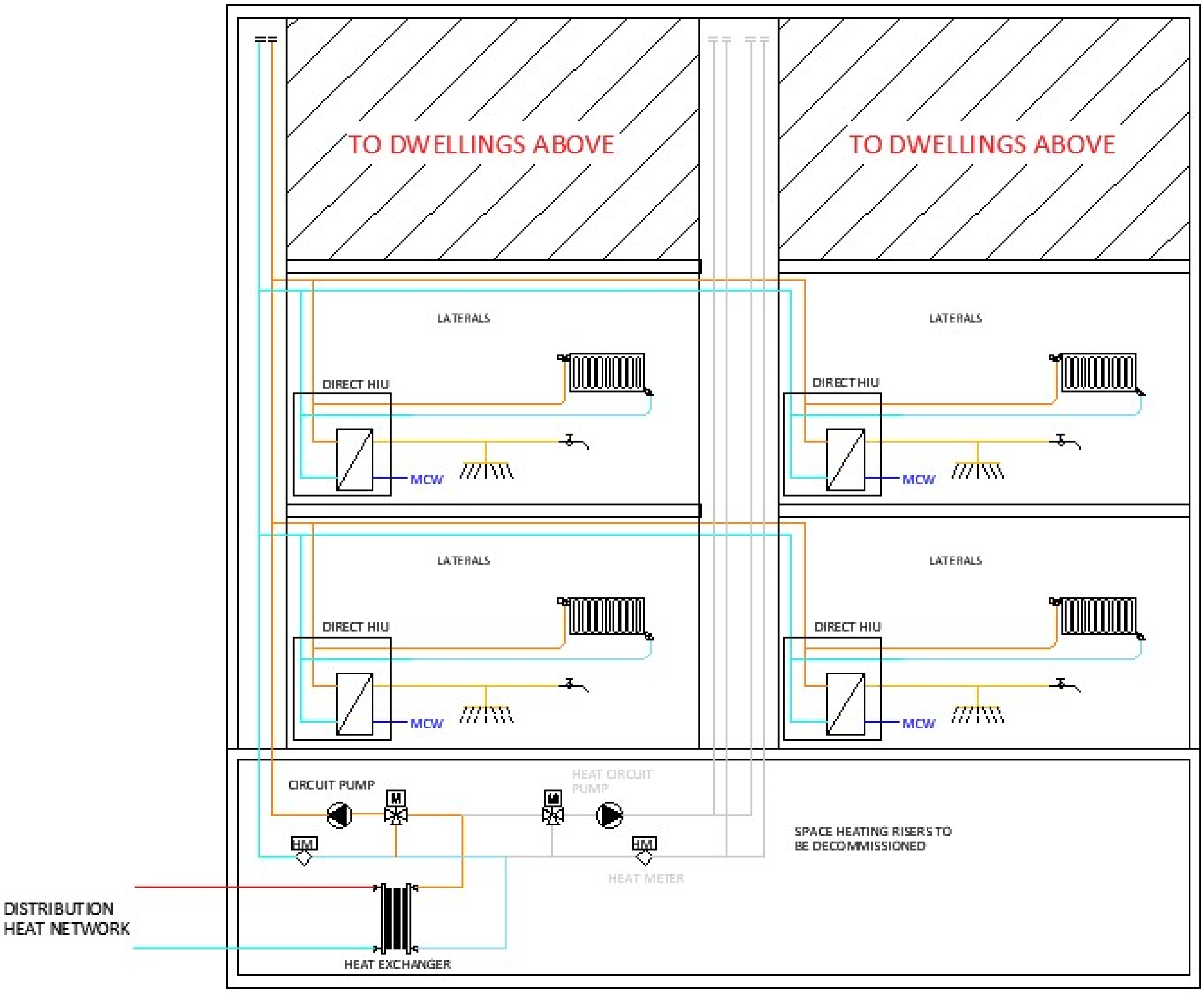

Figure 17: Proposed changes to risers and laterals from 6-pipe to 2-pipe system

Commercial Buildings

The commercial connections will consist of a heat substation. The substation includes heat exchangers, control valves and heat metering and will be maintained by the network operator. The substation can include one or more plate heat exchangers (PHEs) (one shown in the example in Figure 18), depending on the size, turn-down and redundancy required for each building. Only the key functional features are shown in the simplified schematic in Figure 18 (drawing no. S2278-SEL-PP-XX-DR-Y-7004).

The substation packages will include:

- Supplier meter to meter all heat usage on the primary side of the connection.
- Two-port differential pressure control to control the supply flowrate and temperatures across the heat exchanger via two-port control methodology. Control valves can either be a single PICV or a DPCV with a separate two-port control valve.
- Plate heat exchanger (PHE) at which the district heat is transferred to the customer secondary side network. PHEs will be specified with a maximum 3°C approach temperature across the return lines and a maximum 80kPa pressure drop on the secondary side of exchanger.

- Means of flow measurement and test points on both sides for commissioning purposes.
- Filtration to protect the plate heat exchangers and valves from fouling.
- Flushing, filling and draining details for chemical flushing of all pipework on the primary and secondary side.
- Pressure relief, control and instrumentation to allow the supplier control and monitor of the supply of heat.

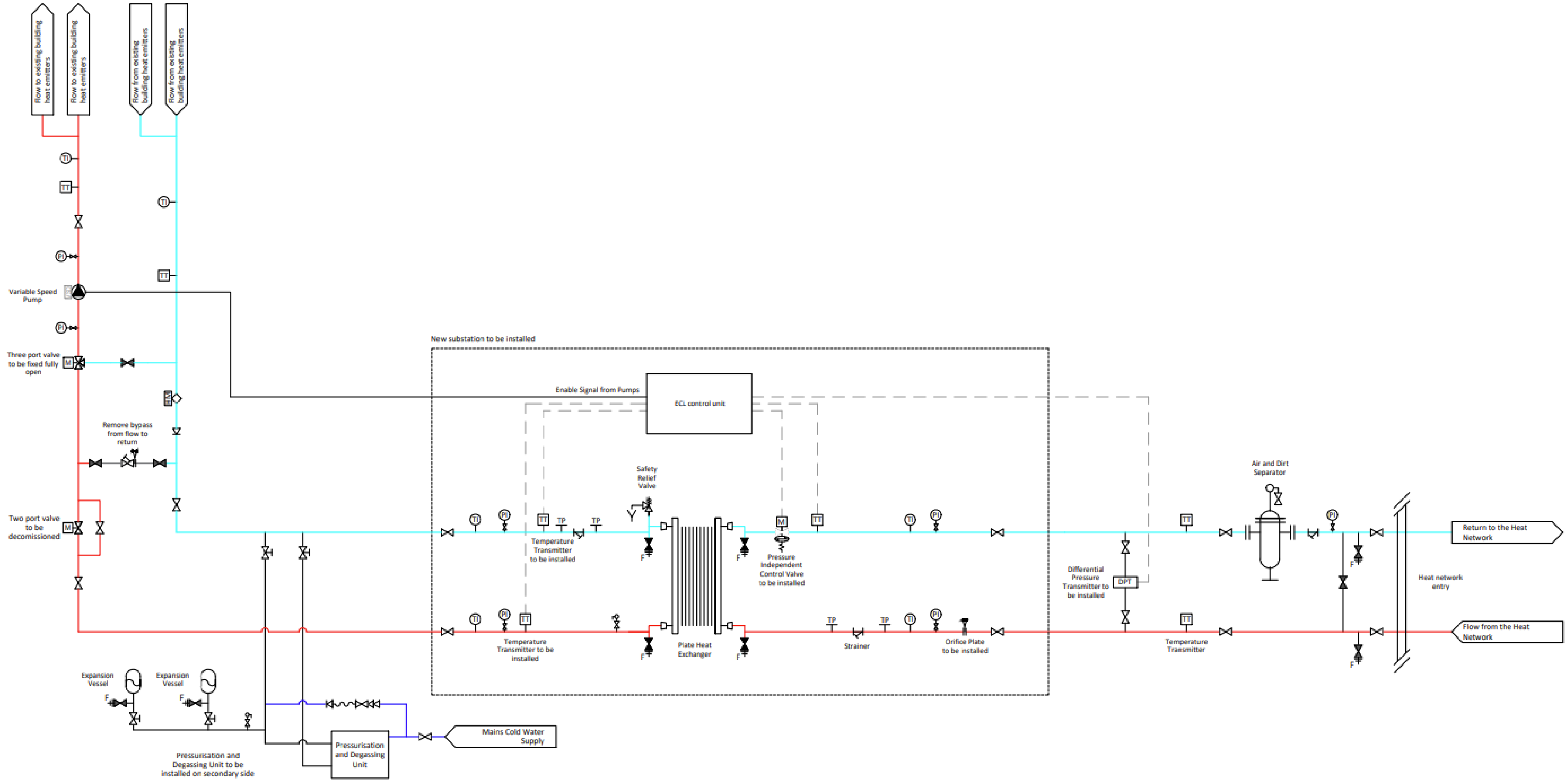

Figure 18: Commercial connection – Jack Hobbs Community Centre

5.6 Heat Network

The proposed scheme utilises the existing network at the Brandon Estate.

5.6.1 Operating Conditions

A detailed assessment of the network has been undertaken and the proposed operating conditions reflect the optimal network efficiency. The heat network will operate with variable temperature conditions to reduce heat losses as much as possible.

5.6.2 Pipe Sizing and Insulation

The existing network route was imported into network modelling software to determine the characteristics and sizing for each part of the network with the aim of minimising pumping energy costs and heat losses. The software allows different scenarios to be modelled and pipe characteristics, such as velocity, pressure loss and temperatures in the pipe are calculated to determine the optimum pipe size, these are shown in Figure 19 and Table 12. Energy centre pumping requirements are also considered to ensure the optimum pipe size is selected.

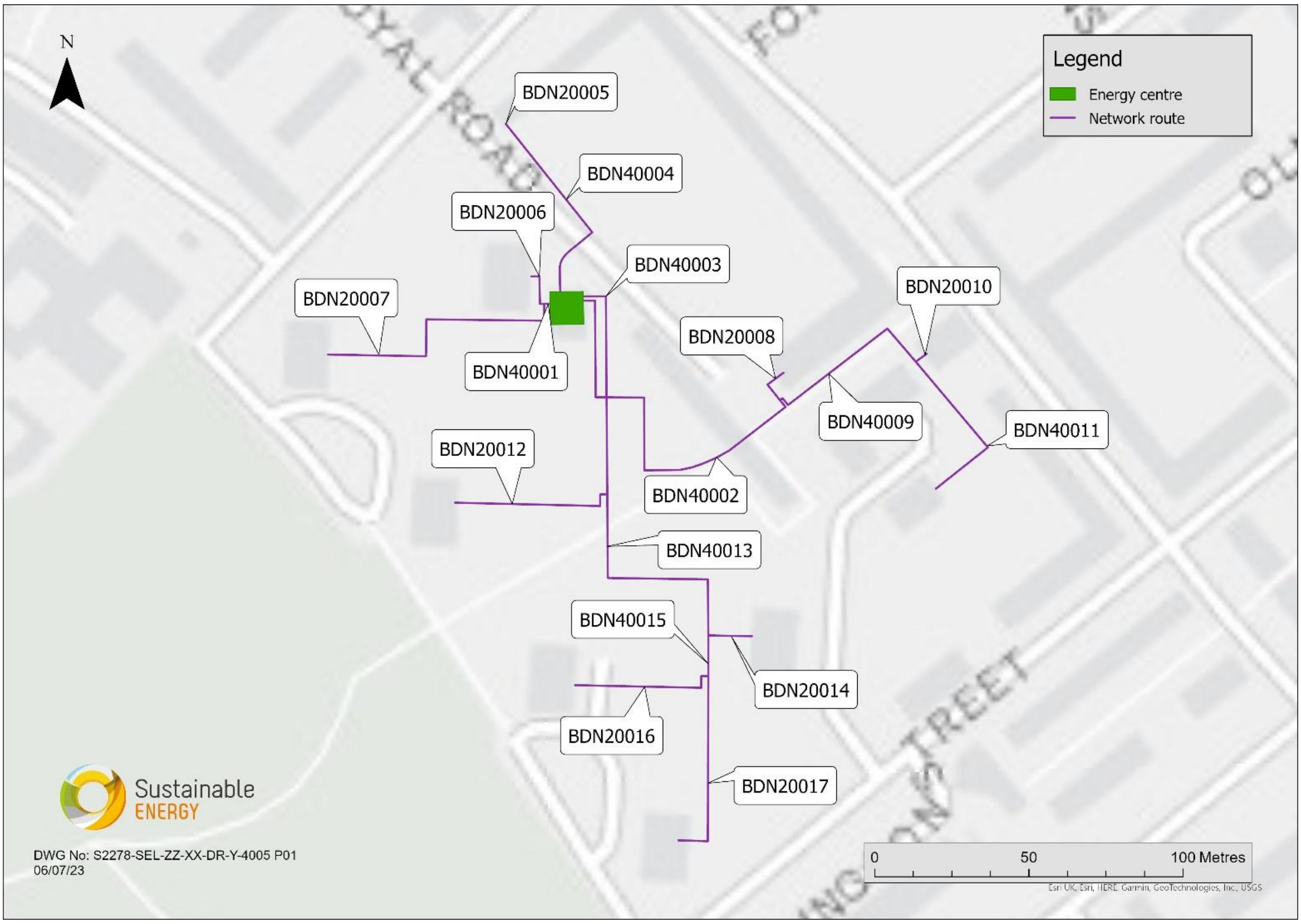

Figure 19: Pipe names

Table 12: Pipe characteristics

Pipe name	Line size	Length, m	Velocity, m/s
BDN20005	DN65	5.5	0.61
BDN20006	DN65	13.0	0.49
BDN20007	DN65	87.5	0.46

Pipe name	Line size	Length, m	Velocity, m/s
BDN20008	DN100	13.0	0.50
BDN20010	DN65	4.4	0.22
BDN20012	DN65	53.2	0.50
BDN20014	DN65	14.1	0.46
BDN20016	DN65	47.1	0.50
BDN20017	DN65	63.1	0.47
BDN40001	DN100	5.3	0.41
BDN40002	DN100	136.7	0.73
BDN40003	DN150	79.0	0.37
BDN40004	DN100	64.8	0.26
BDN40009	DN80	58.6	0.39
BDN40011	DN65	56.0	0.31
BDN40013	DN100	77.8	0.62
BDN40015	DN80	13.2	0.70

6 TECHNO-ECONOMIC MODELLING

A TEM has been constructed to assess the economics of the prioritised heat pump and gas CHP network option. The key assumptions for the TEM and key parameters are shown in Appendix 2: Key Parameters and Assumptions.

The sensitivity of all key assumptions and energy tariffs has been assessed and is shown in section 8. The TEM provided with this report allows key variables to be revised and the associated impact assessed.

6.1 Model Structure

Figure 20 shows an overview of the tabs included in the TEM. Tabs relevant to the standard user are shown in grey. These tabs include the key model inputs and variables and display the key results from the model. Tabs that involve technical inputs and calculations are shown in green. Inputs in these tabs have been input from the SEL technology sizing tool (see Appendix 3: Technology Sizing) and are set for each phase. A user guide and full list of assumptions have also been included in the TEM.

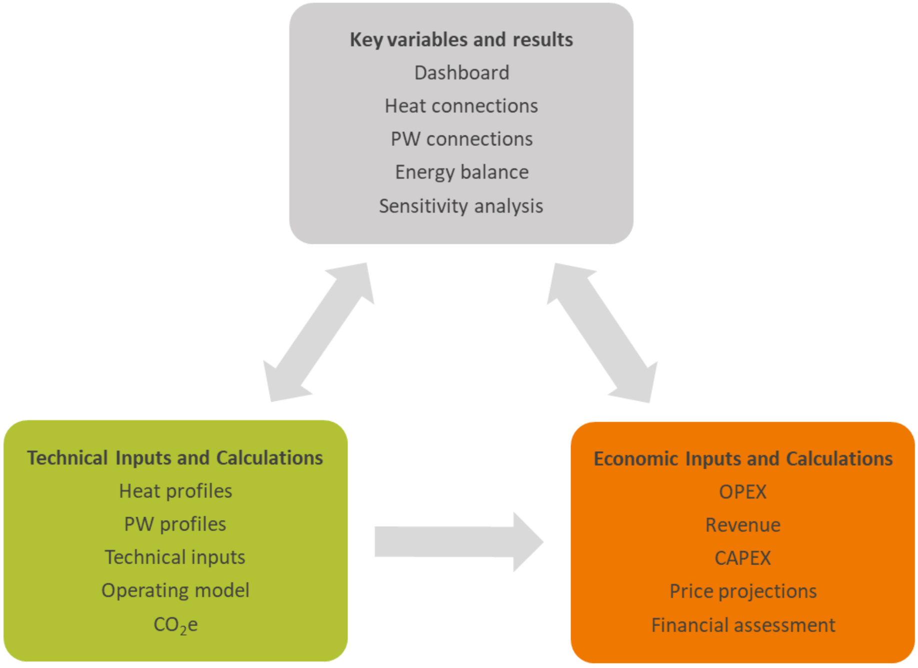

Figure 20: TEM tab structure

6.2 Energy Tariffs

6.2.1 Energy Sales Tariffs

The heat sales tariffs have been calculated based on LBS' borough wide methodology for tenants and leaseholders. The heat sale tariff for tenants is 11.56 p/kWh with a standing charge of £0.47-£0.64 per day depending on dwelling size. The leaseholder variable heat sale tariff is based on the fuel costs and efficiency of the heat network, resulting in 10.52 p/kWh in phase 1 which increases to 14.57 p/kWh (in current prices) in phase 3 when the gas CHP is removed. The leaseholder heat sales tariffs vary in line with the energy centre fuel costs and price projections, discussed in section 6.4. Further details of heat sales tariff calculations are shown in Appendix 2: Key Parameters and Assumptions. These can be varied in the TEM.

6.2.2 Energy Centre Tariffs

The current energy centre tariffs at the Brandon estate have been used in the assessment. These include gas prices of 7.83 p/kWh and a standing charge of £75.27 a day, and electricity prices of 31.60 p/kWh day and 31.05 p/kWh night tariffs.

The electricity standing charge has been calculated based on UKPN's fixed and capacity charges. LBS do not currently pay CCL charges at Brandon and therefore they have not been included in this assessment.

6.3 Initial Capital and Replacement Costs

Technology replacement costs are modelled on an annualised basis and consider the capital costs, expected lifetime, fractional repairs and the length of the business term. Details of expected equipment lifetime and fractional repairs are shown in Appendix 2: Key Parameters and Assumptions.

Capital costs for the scheme are based on a combination of previous project experience, quotations for recent similar works and soft market testing. Soft market testing has been conducted with potential suppliers of plant and equipment.

Estimated capital costs for key plant items (such as heat pumps, thermal storage tanks, etc.) have been obtained from the respective suppliers. Replacement costs for the gas CHP unit have not been included as it will not be replaced at the end of its life.

By using the above methodology, CAPEX estimates are within the tolerance stated in the project requirements and contingency has been applied to each element of capital expenditure as appropriate. A breakdown of capital costs and contingency values for each phase are shown in Appendix 2: Key Parameters and Assumptions.

Capital costs have not been included for network pipes or energy centre building, as the existing network and energy centre building will not be replaced. It is also proposed to utilise the existing peak and reserve plant, therefore costs for gas boilers and gas boiler flues have not been included. The existing gas grid connection is sufficient for connection of the gas CHP so no additional costs are likely to be required.

6.3.1 Secondary and Tertiary Side Costs

Tertiary, dwelling upgrades are included in the phase 1 scheme CAPEX and includes the purchase and installation of HIUs (direct for all but Cooks Road and Napier House), copper pipework, and radiators. The secondary side upgrades of the housing blocks include the replacement of risers and laterals that will occur in phase 2. An example of the breakdown of costs for secondary and tertiary upgrades in Bateman House is shown in Table 13.

Table 13: Secondary and tertiary network costs

Network element	Description	Cost per dwelling	Cost per block	Phase installed
Tertiary	Direct HIU	£2,095	£142,446	Phase 1
	Radiators	£1,522	£103,473	
	Copper pipework	£2,760	£187,680	
Secondary	Risers and laterals	£2,320	£157,786	Phase 2

Secondary side costs for heating system upgrades at both Brandon Library and Jack Hobbs Community Centre were also included alongside a new substation for Jack Hobbs.

6.3.2 Leaseholder Contributions

Leaseholders will pay their share of the scheme operational costs (excluding fuel costs as these are covered in the heat sales tariff) as part of their monthly service charge to LBS. These costs are included in the base case assessment.

Leaseholders will also pay for their own tertiary side (dwelling heating system upgrades) costs and their share of the energy centre and building secondary side CAPEX. As these costs are charged to leaseholders after the work has been completed, the base case shown in the economic assessment in section 6.6 excludes these costs. The effect of including these leaseholder charges is shown in section 6.6.1. These can also be varied in the TEM.

6.4 Fossil Fuel Price Projections

To assess the impact of expected future price changes on the financial outputs, the central scenario price projections for natural gas and electricity have been used (last updated July 2023[4]). The projected changes in prices for electricity and natural gas for residential, services and industrial is illustrated in Figure 21. The projected price variations have been applied to the energy tariffs calculated as discussed in section 6.2.

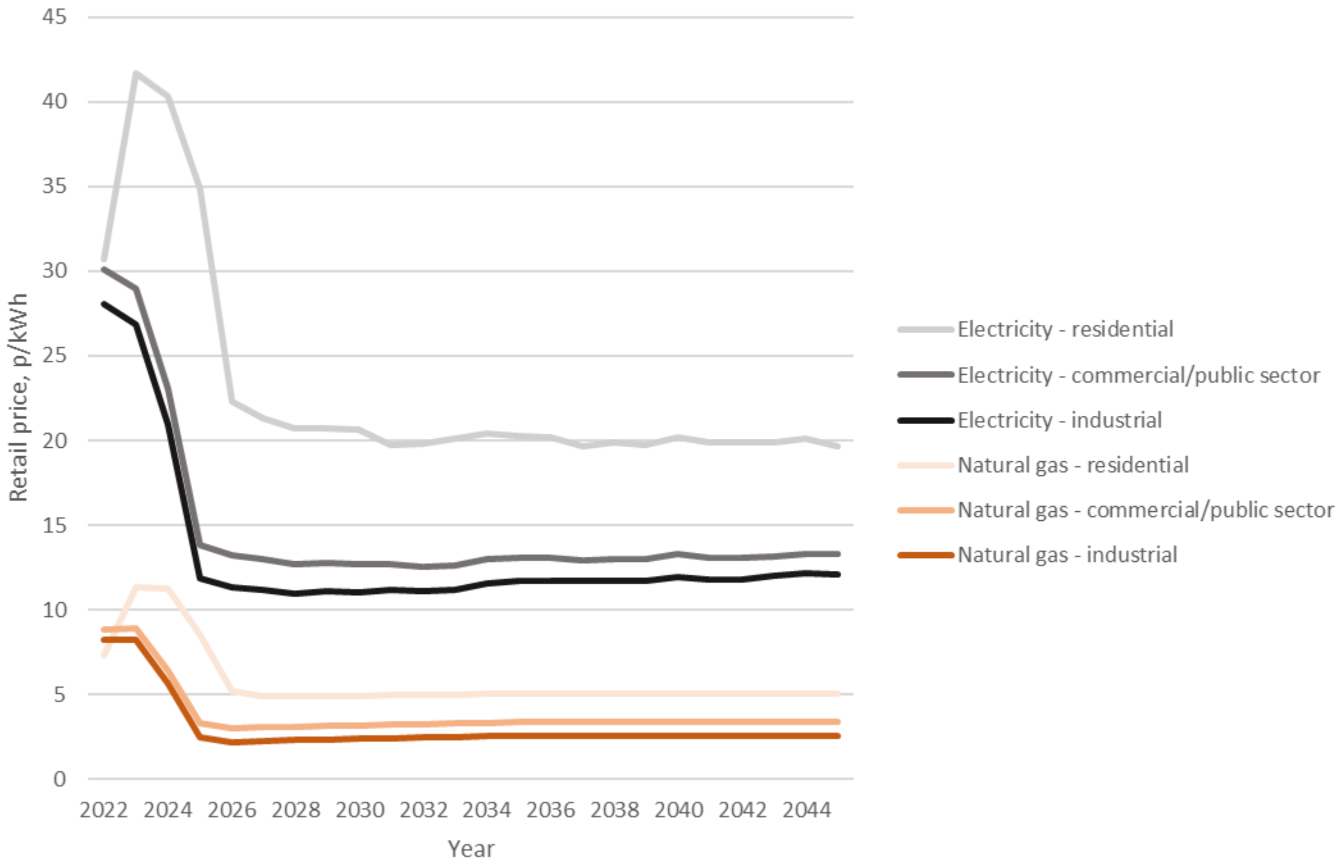

Figure 21: Fossil fuel price projections – central scenario, updated July 2023

The above projections indicate there is likely to be a significant drop in both gas and electricity retail prices over the next few years. The impact of a decrease in energy tariff retail prices is shown in section 8.

6.5 Network Summary

A heat network supplied by a ground source heat pump and gas CHP located at the existing Brandon energy centre has been selected as the prioritised network option. Three phases have been included in the TEM. The network and connections remain the same for all phases. Phase 2 and 3 show the impact of the following changes:

- Phase 1: The proposed network supplied by GSHP and gas CHP
- Phase 2: Phase 1 network with upgraded risers (resulting in lower building heat losses)

[4] Data tables 4 and 5: https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

- Phase 3: Phase 2 network without the gas CHP

It is assumed a 1 MW GSHP and 252 kWth gas CHP will be able to provide 92 % of the network heat demand for phase 1 (prior to the upgrade of the risers). A summary of the network heat generation and supply is shown in Table 14.

Table 14: Network summary

	Phase 1	Phase 2	Phase 3
Building heat demand (not including network losses)	5,414 MWh		
Total network heat demand (including network losses)	7,236 MWh	6,253 MWh	
Peak heat demand	2.2 MW	2.1 MW	
GSHP capacity	1 MW		
Gas CHP capacity	200 kWe/252 kWth		-
Total low carbon capacity	1.25 MW		1 MW
Heat demand met by heat pumps, gas CHP and thermal store	6,661 MWh	5,883 MWh	5,444 MWh
Heat demand met by peak and reserve boilers	575 MWh	369 MWh	809 MWh
% heat demand met by low carbon / renewable technology	92 %	94 %	87 %

Figure 22 shows the hourly network heat demand ordered from highest to lowest. Heat demand below the black line can be met by the heat pump and gas CHP (shown for phase 1). The heat demand above the black line is met by the thermal stores and peak and reserve boilers. The peak and reserve boilers will also supply heat in the 2 weeks plant downtime a year included in the assessment for maintenance and repairs to the heat pump and gas CHP.

The heat pump and gas CHP will meet between 92 % of the total network heat demand for phase 1 and 94 % for phase 2 once the building losses have been reduced through upgraded risers. The heat pump will then be able to meet 87 % of the heat demand once the gas CHP has been removed in phase 3.

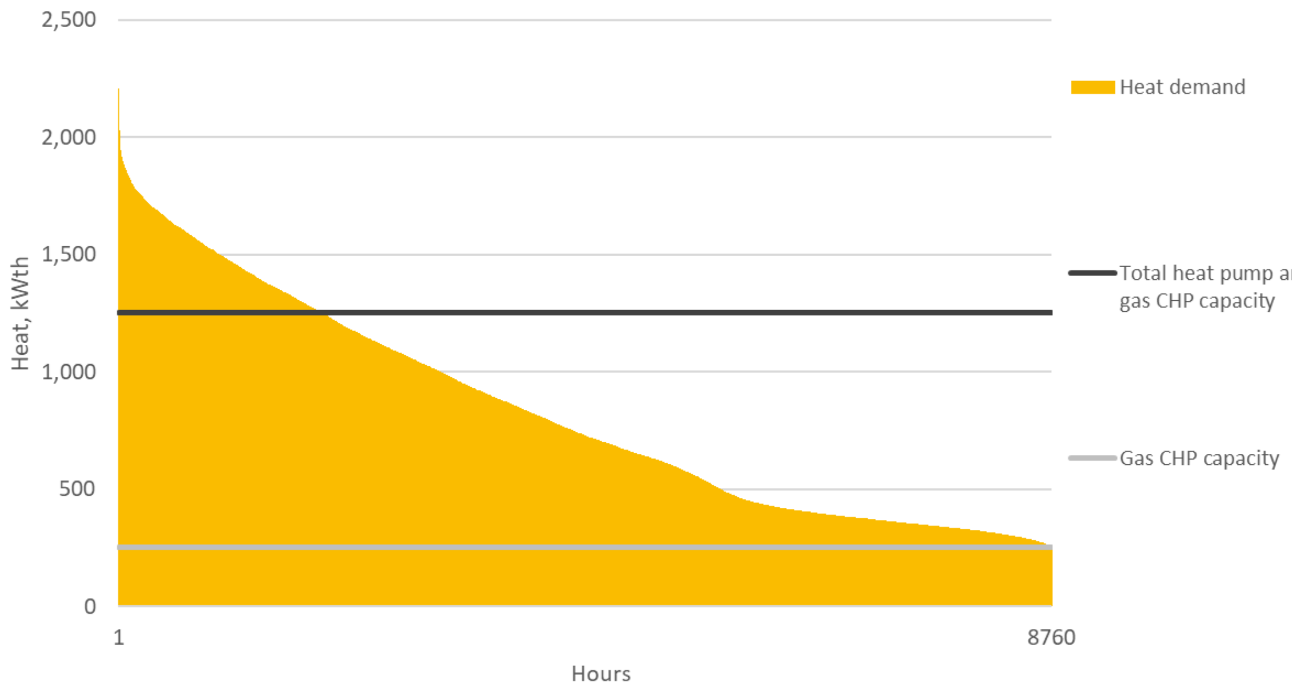

Figure 22: Load duration curve – phase 1

6.5.1 Energy Balance

Figure 23, Figure 24 and Figure 25 show the energy balance for phases 1, 2 and 3 respectively.

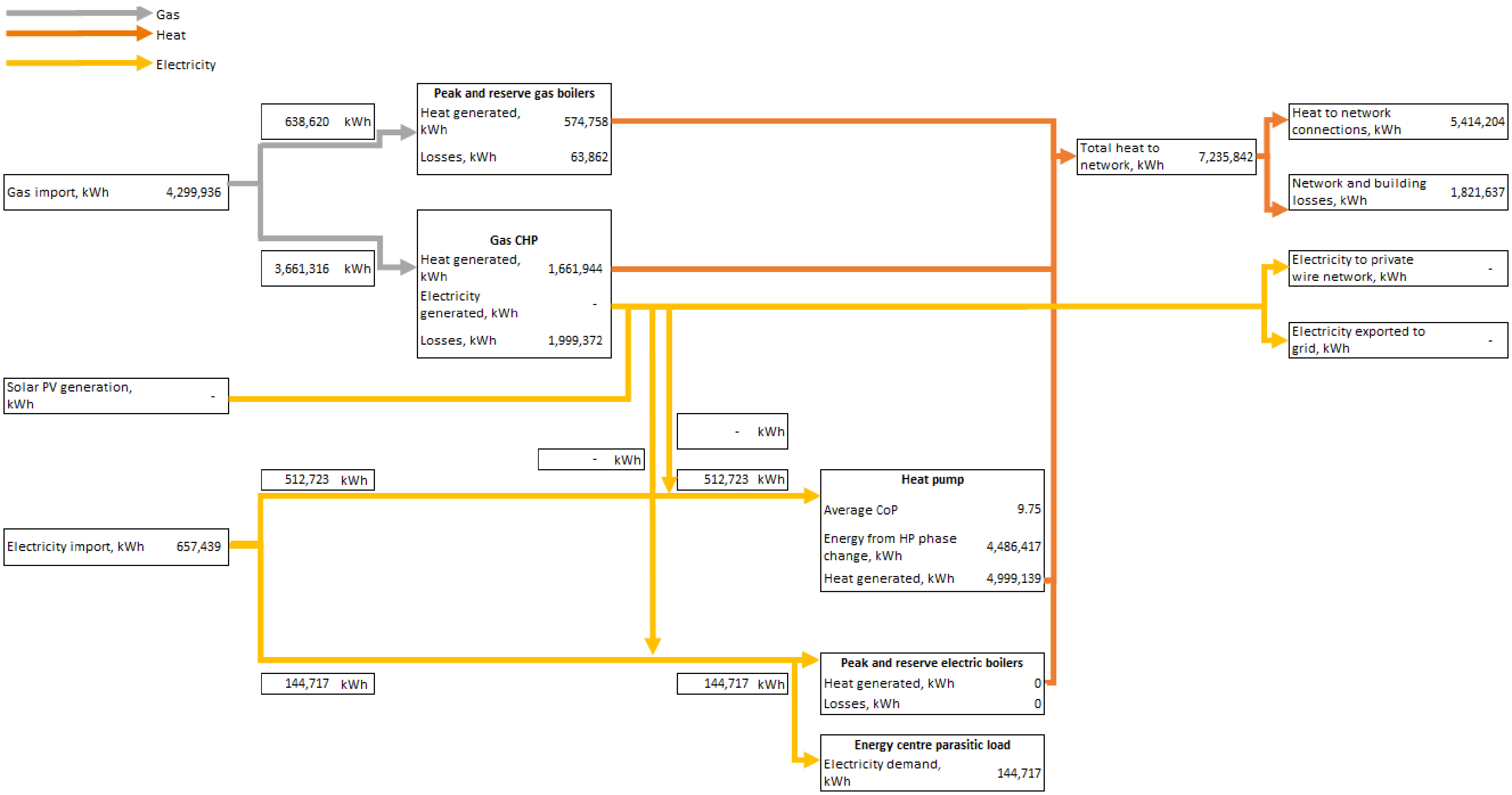

Figure 23: Phase 1 energy balance

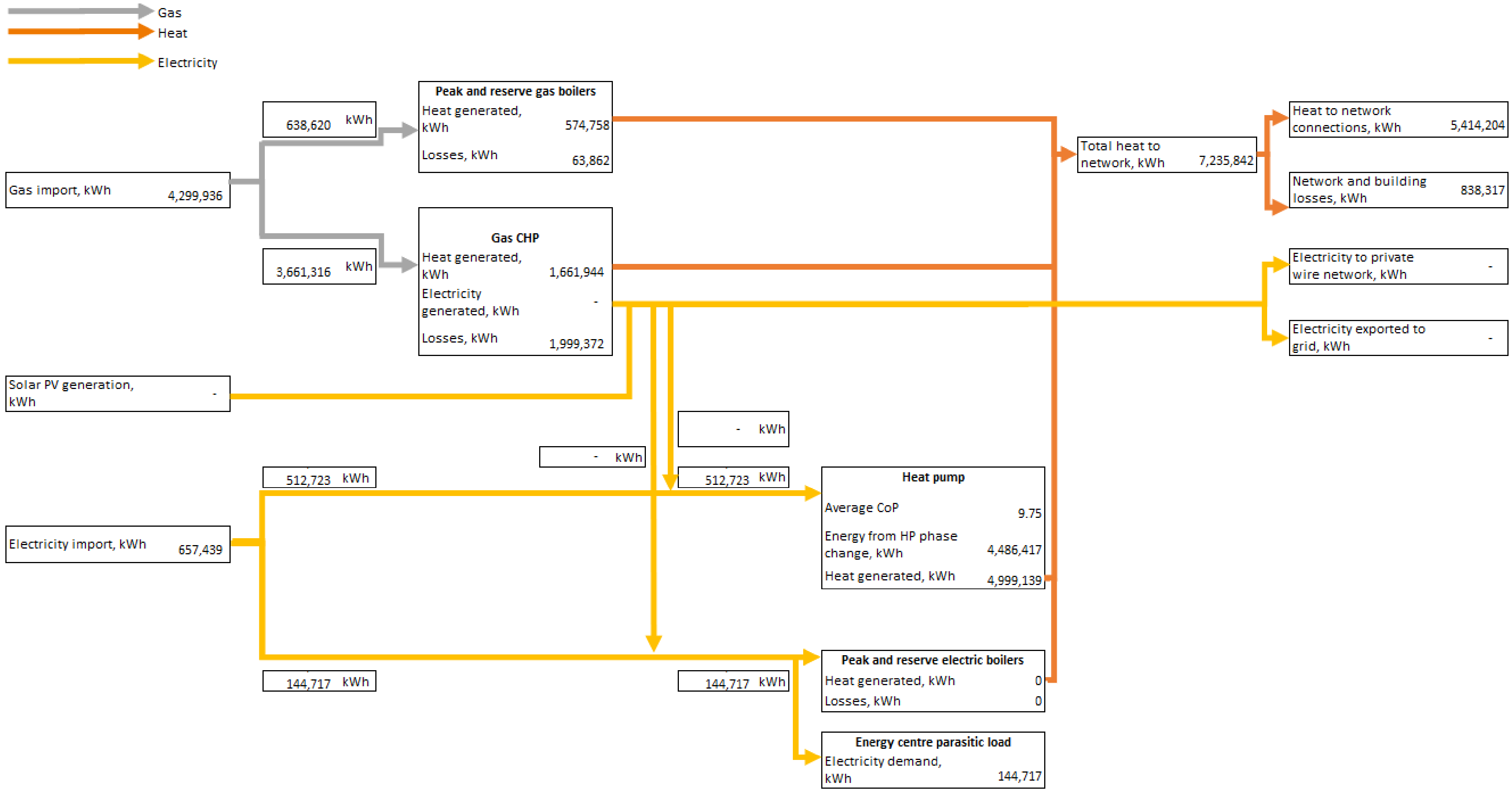

Figure 24: Phase 2 energy balance

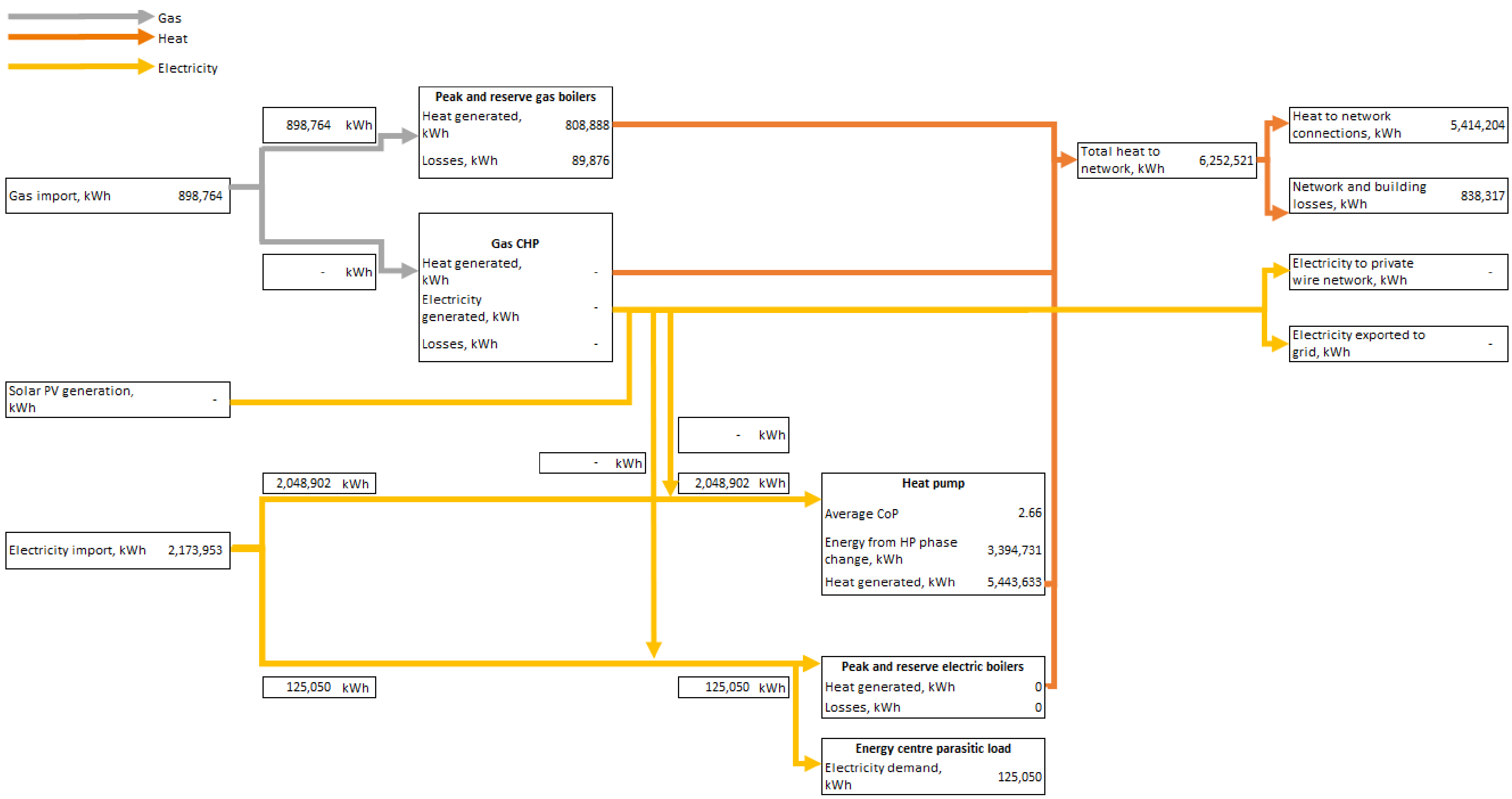

Figure 25: Phase 3 energy balance

6.6 Economic Assessment

The 25 year, 30 year and 40 year economic assessments for each phase of the network are shown in Table 15. Figures do not include any grant funding.

Table 15: Economic assessment

		Phase 1	Phase 2	Phase 3
Capital costs for each phase (including contingency)		£6,452,116	£1,191,908	-
Total capital costs (including contingency)			£7,664,024	£7,664,024
25 years	IRR	-1.1%	-1.7%	-3.7%
	NPV	-£2,927,352	-£3,398,945	-£3,910,519
	Simple payback	Does not payback	Does not payback	Does not payback
	Net income	-£866,475	-£1,391,795	-£2,529,444
30 years	IRR	-0.1%	-0.3%	-2.4%
	NPV	-£2,727,435	-£3,124,542	-£3,827,820
	Simple payback	Does not payback	Does not payback	Does not payback
	Net income	-£64,059	-£366,205	-£2,078,241
40 years	IRR	1.1%	1.1%	-1.0%
	NPV	-£2,440,704	-£2,726,292	-£3,716,589
	Simple payback	33 years	33 years	Does not payback
	Net income	£1,540,772	£1,684,975	-£1,175,835

The capital costs, operational expenditure, revenue, and cumulative cash flow is shown in Figure 26 for 40 years.

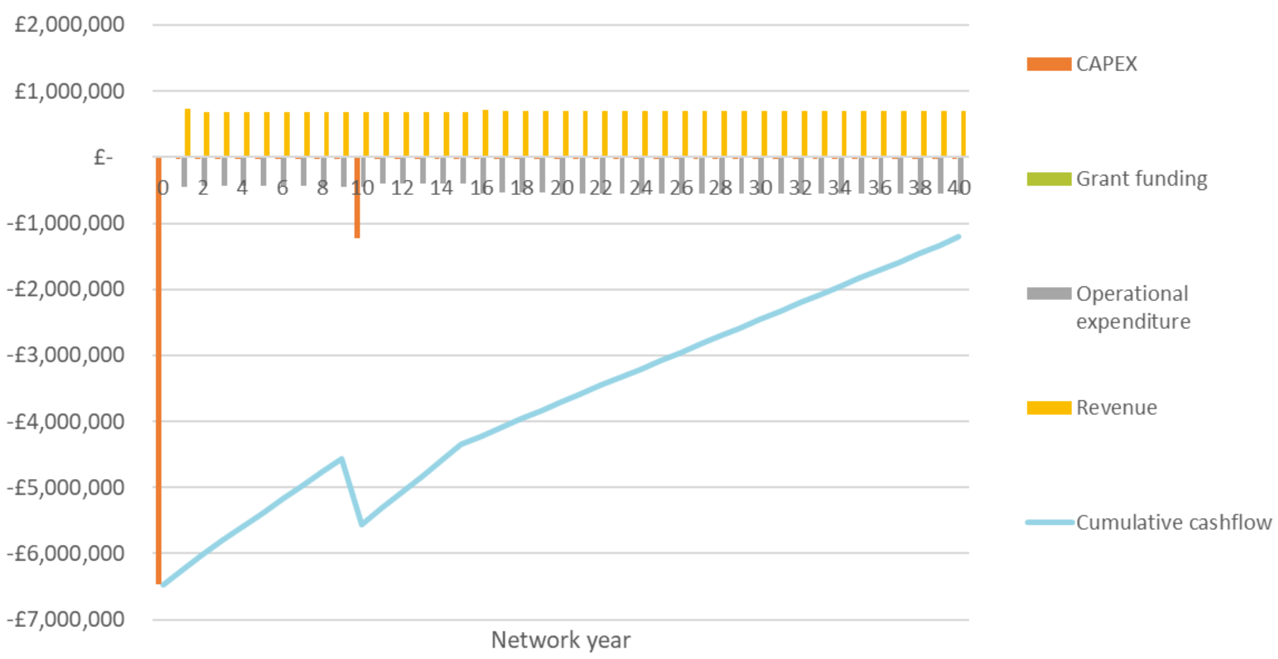

Figure 26: Cumulative cash flow – 40 years

6.6.1 Savings in Operating Costs

Table 16 shows the savings between the current annual operating costs of the network at Brandon and the proposed scheme.

Table 16: Savings in OPEX

OPEX item	Current cost	Proposed scheme cost	Annual saving
Gas costs	£1,000,743	£364,159	£636,584
Electricity costs	£72,547	£208,400	-£135,853
Repairs and maintenance costs	£107,018	£92,420	£14,598
Overhead	£65,868	£65,000	£868
Metering and billing	£67,903	£67,903	-
Total annual cost	**£1,314,078**	**£797,882**	**£516,197 (39%)**

6.6.2 Leaseholder Charges

Table 17 shows the annual charges payable by the leaseholders, which is lower than the annual cost of heat they are currently charged.

Table 17: Annual leaseholder charges

	Annual leaseholder charges
Energy element of the service charge	£216
Annual cost of heat	£1,229
Current annual cost of heat	£2,690

A breakdown of the scheme CAPEX that will be attributed to LBS and to the leaseholders is shown in Table 18.

Table 18: Total, LBS, and leaseholder CAPEX

	Total costs	Costs to LBS	Total costs to leaseholders	Costs to leaseholders per dwelling
Energy centre CAPEX	£2,504,367	£1,889,511	£614,856	£4,488
Secondary network costs (phase 2)	£1,191,908	£911,840	£280,068	£2,044
Tertiary network costs	£3,947,749	£2,995,850	£951,899	£6,948
Total CAPEX	£7,644,024	£5,797,201	£1,846,823	£13,480

The 25 year, 30 year and 40 year economic assessments for each phase of the network are shown in Table 15. Figures do not include any grant funding.

Table 19: Economic assessment with capital leaseholder contribution charges

<table>
<tr><th colspan="2"></th><th>Phase 1</th><th>Phase 2</th><th>Phase 3</th></tr>
<tr><td colspan="2">Capital costs for each phase (including contingency)</td><td rowspan="2">£6,452,116</td><td>£1,191,908</td><td>-</td></tr>
<tr><td colspan="2">Total capital costs (including contingency)</td><td>£7,664,024</td><td>£7,664,024</td></tr>
<tr><td colspan="2">Leaseholder contributions</td><td>£1,566,771</td><td>£1,846,839</td><td>£1,846,839</td></tr>
<tr><td colspan="2">Remaining capital costs</td><td>£4,885,345</td><td>£5,797,186</td><td>£5,797,186</td></tr>
<tr><td rowspan="2">25 years</td><td>IRR</td><td>1.1%</td><td>0.6%</td><td>-1.2%</td></tr>
<tr><td>NPV</td><td>-£1,420,842</td><td>-£1,710,547</td><td>-£2,222,121</td></tr>
</table>

		Phase 1	Phase 2	Phase 3
	Simple payback	22 years	24 years	0 years
	Net income	£700,296	£455,044	-£682,605
30 years	IRR	1.8%	1.6%	-0.3%
	NPV	-£1,220,924	-£1,436,144	-£2,139,422
	Simple payback	23 years	25 years	0 years
	Net income	£1,502,712	£1,480,634	-£231,402
40 years	IRR	2.7%	2.7%	0.7%
	NPV	-£934,194	-£1,037,894	-£2,028,191
	Simple payback	25 years	26 years	35 years
	Net income	£3,107,543	£3,531,814	£671,003

6.7 Grant Funding

6.7.1 Green Heat Network Fund

DESNZ provides capital support for heat network developments seeing them as a key part of delivering the UK's legally binding commitment to achieve net zero by 2050. As such they have made capital support available to projects via the Green Heat Network Fund (GHNF) which was launched in April 2022.

GHNF is a £288m fund available to support heat network project with capital grants available to up to but not including 50% of the project capex. Table 20 shows GHNF criteria and the parameters for phase 1 of the preferred network option.

Table 20: GHNF core metrics

Metric	Minimum score	Phase 1
Carbon gate	100 gCO_2e/kWh thermal energy delivered	76 gCO_2e/kWh reached in year 1 of operation
Customer detriment	Domestic and micro-businesses must not be offered a price of heat greater than a low carbon counterfactual for new buildings and a gas/oil counterfactual for existing buildings	Customer heat sales tariffs have been calculated based on LBS' borough wide tariff methodology for tenants and leaseholders. Proposed tariffs are lower than the customers' current energy costs.
Social IRR	Projects must demonstrate a Social IRR of 3.5% or greater over a 40-year period	The 40-year social IRR is above 3.5 % for phase 1.
Minimum demand	For urban networks, a minimum end customer demand of 2 GWh/year. For rural networks, a minimum number of 100 dwellings connected	End customer demand is 5.4 GWh/year.
Maximum capex	Grant award requested up to but not including 50% of the combined total capex + commercialisation costs (with an upper limit of £1 million for commercialisation)	Grant funding request amount to be determined.
Capped award	The total 15-year kWh of heat/cooling forecast to be delivered will not exceed 4.5 pence of grant per kWh delivered (subject to review by GHNF)	Grant funding request amount to be determined.
Non-heat/cooling cost inclusion	For projects including wider energy infrastructure in their application, the value of income generated/costs saved/wider subsidy obtained	No non-heat/cooling infrastructure included.

Metric	Minimum score	Phase 1
	should be greater than or equal to the costs included.	

The Brandon Estate network is likely to be viable for grant funding from the GHNF. The impact of GHNF funding on the energy centre CAPEX is shown in section 6.7.3.

6.7.2 Heat Network Efficiency Scheme

The heat network efficiency scheme (HNES) was launched to help improve existing heat networks. The scheme aims to enable optimisation studies to identify actions to optimise heat network operation and to deliver eligible intervention and improvement measures. £32 million grant support is available, and the scheme is open to public, private and third sectors in England and Wales. The scheme is open for applications from projects that will:

- Reduce carbon emissions by making heat networks more efficient
- Reduce customer detriment to improve consumer confidence
- Help prepare the heat network market for sector regulation and technical standards

HNES funding can provide up to (but not including) 50 % of eligible project costs for capital grant applications and up to 100 % of eligible project costs for revenue (optimisation study) grant applications.

Like with the GHNF application process, applications are awarded funding on a competitive basis. This means that even if an application meets all the eligibility criteria and scores well, there is no guarantee of a funding award. Funding will be allocated to maximus benefits and will prioritise projects which provide value for money and address:

- Customer detriment (prioritising projects with high proportions of “customers in need”)
- Network operational performance (efficiency/losses and deliver carbon emissions savings

The proposed Brandon Estate Network is likely to be eligible for HNES funding based on the above criteria. The impact of HNES grant funding on the secondary and tertiary side CAPEX is shown in section 6.7.3.

6.7.3 Impact of Grant Funding on Network Economics

Grant funding requests have yet to be determined, however, as an example Table 21 shows the impact of £876,528 (35%) of GHNF and £1,934,397 (49%) of HNES funding on the phase 1 network economics with and without CAPEX contributions from leaseholders. The total grant funding shown in Table 21 is shown as an example only and the effect of an increase or decrease is shown in section 8.2.

Table 21: Impact of grant funding on phase 1 economics

		Phase 1 (not including leaseholder charges)	Phase 1 (including leaseholder charges)
Total capital costs (including contingency)		£6,452,116	
GHNF grant funding		£876,528	
HNES grant funding		£1,934,397	
Total grant funding		£1,405,463	
Leaseholder capital contribution charges		-	£1,100,340
Remaining capital costs		£3,641,190	£2,540,850
40 years	IRR	4.7 %	7.4 %
	NPV	£370,221	£1,428,240
	Simple payback	18 years	13 years

		Phase 1 (not including leaseholder charges)	Phase 1 (including leaseholder charges)
	Net income	£4,351,697	£5,452,037

The capital costs, operational expenditure, revenue, and cumulative cash flow for the full network with GHNF funding in Phase 1 is shown in Figure 27 or 40 years.

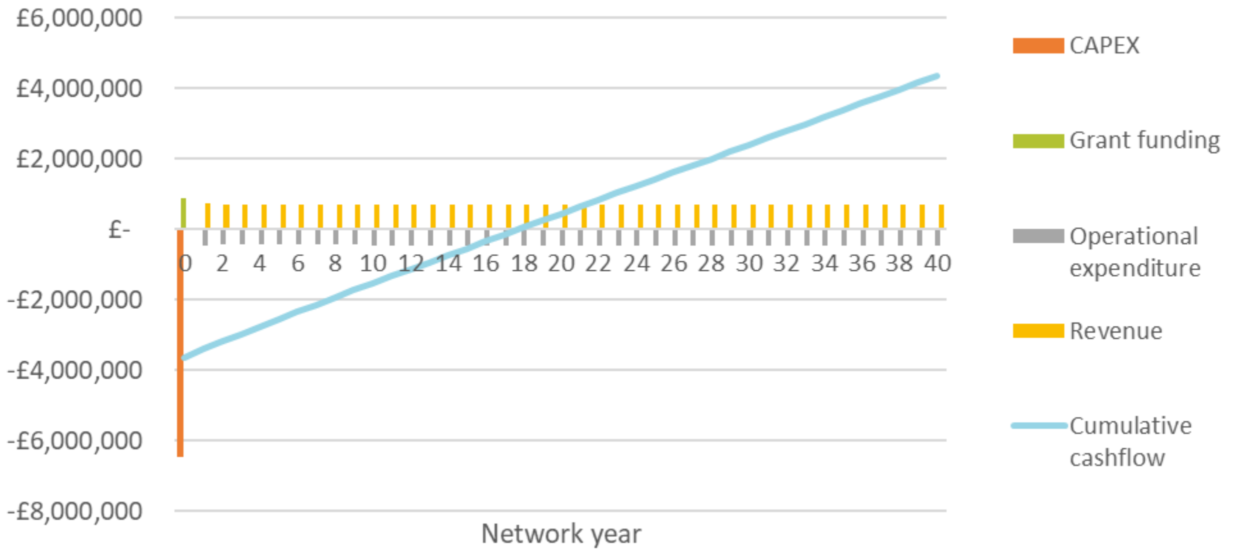

Figure 27: Cumulative cash flow with GHNF and HNES in phase 1 - 40 years

7 ENVIRONMENTAL BENEFITS AND IMPACTS

The following section describes the benefits and impacts associated with the recommended network options. The CO_2e emissions have been assessed annually for each phase for 40 years. This has been compared to the business as usual (BAU) emissions and overall CO_2e savings calculated.

7.1 CO_2e emission assessment

The CO_2e emissions have been assessed annually for each network option for 25, 30 and 40 years. This has been compared to the business as usual (BAU) emissions and overall CO_2e savings calculated.

CO_2e intensity projections for grid electricity and natural gas are shown in Figure 28. The CO_2e emissions for the electricity grid are expected to reduce over time due to the increase in wind, solar and nuclear power and the closure of coal power stations.

Two CO_2e projections for grid electricity have been considered:

- BEIS long run marginal figure (commercial)
- BEIS long run marginal figures (residential)

The BEIS marginal emissions factors consider the marginal plant for electricity generation. The projections are based on assumptions of future economic growth, fossil fuel prices, electricity generation costs, UK population and other key variables which are regularly updated. They also give an indication of the impact of the uncertainty around some of these input assumptions. Each set of projections takes account of climate change policies where funding has been agreed and where decisions on policy design are sufficiently advanced to allow robust estimates of policy impacts to be made.

These figures have been used for all electricity imported from the grid (i.e., for heat pump and energy centre electricity demand).

Figure 28: CO_2e emissions projections

7.1.1 Network Emissions

The current network at Brandon and the 2022/23 gas usage has been assumed as the BAU for all network phases. BAU CO_2e intensity and network CO_2e intensity for the network are shown in Figure 29 and Table 22. The BAU emissions remain constant due to the constant natural gas emissions factor used in assessments. The network emissions reduce marginally over time as the grid decarbonises and once the gas CHP is removed in phase 3.

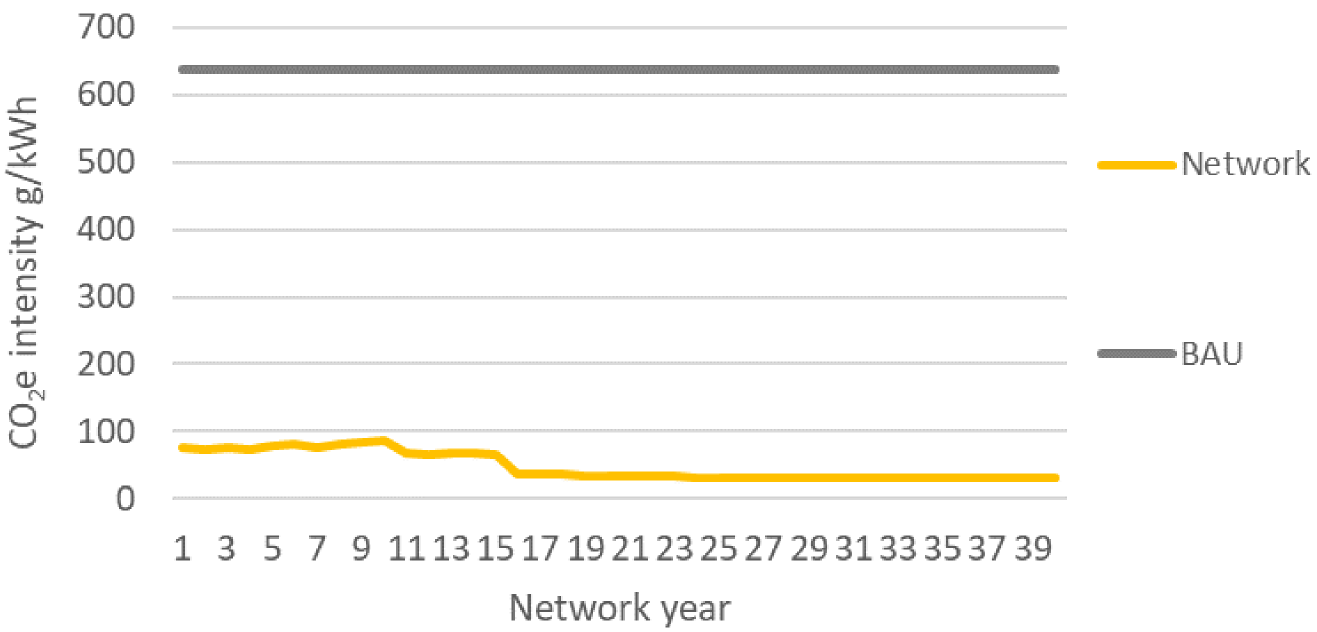

Figure 29: Network CO_2e emissions and savings – 40 years

Table 22: Network CO_2e emissions and savings

		Phase 1	Phase 2	Phase 3
25 years	Network CO_2e emissions, tCO_2e	11,364	9,777	7,891
	CO_2e savings, tCO_2e	45,367	46,954	48,839
30 years	Network CO_2e emissions, tCO_2e	13,772	11,664	8,739
	CO_2e savings, tCO_2e	54,305	56,413	59,338
40 years	Network CO_2e emissions, tCO_2e	18,587	15,438	10,433
	CO_2e savings, tCO_2e	72,181	75,331	80,336
Annual CO_2e savings (year 1), tCO_2e			1,855	
CO_2e intensity of heat delivered (year 1), gCO_2e/kWh			76	
CO_2e intensity of heat delivered (40-year average), gCO_2e/kWh		86	71	48

7.2 Air Quality

Two of the existing gas boilers have been included in the base case, they should be compliant with the Medium Combustion Plant Directive. Gas boilers will run only at peak heat demands and when the heat pumps are not operating. The low carbon technology has been sized to meet >90 % of the network heat demand in wherever possible.

If electric peak and reserve boilers could be considered as long term replacements for the gas boilers. However if they are installed, they will decrease the economic viability of the network due to the increased cost of electricity versus gas and the increased fixed charge based on required capacity (particularly in the short term) and significantly increase risk associated with the resilience and reliability of the centralised heat pumps (if the heat pumps are unavailable for significant periods, the operation electric peak and reserve boilers may be an unacceptable risk for O&M contractors obligated to deliver heat at a specific price).

7.3 Social IRR and NPV

The environmental benefits to the scheme are determined by monetising the CO_2e savings and the improvements in air quality against the use of individual gas boilers. The economic value of the carbon and air quality improvements are included in the project cashflow to generate a social IRR and NPV, shown in Table 23. The social IRR helps to identify the wider benefits of the scheme for the community and is a vital consideration for local authorities.

Table 23: 40 year social IRR and NPV

	IRR	Social IRR	NPV	Social NPV
Phase 1	1.1%	11.7%	£1,540,772	£9,344,620
Phase 2	1.1%	11.4%	-£2,726,292	£9,509,980
Phase 3	-1.0%	11.4%	-£3,716,589	£9,509,980

8 SENSITIVITY ANALYSIS

Sensitivity analysis has been undertaken for the prioritised network based on the key network risks, parameters, and variables. The base case 40-year IRRs are shown in grey cells in tables.

Key risks for the network include:

- Capital costs
- Grant funding
- Network heat demand
- Energy tariffs including heat sales tariffs, energy centre fuel purchase tariffs and indexation of energy tariffs

8.1 Capital Cost

The effect of a variance in capital costs is shown in Figure 30 for each network phase. A decrease in capital costs of approximately over 30% would be required for Phase 1 to achieve an IRR of 4% and achieve an NPV of £0.

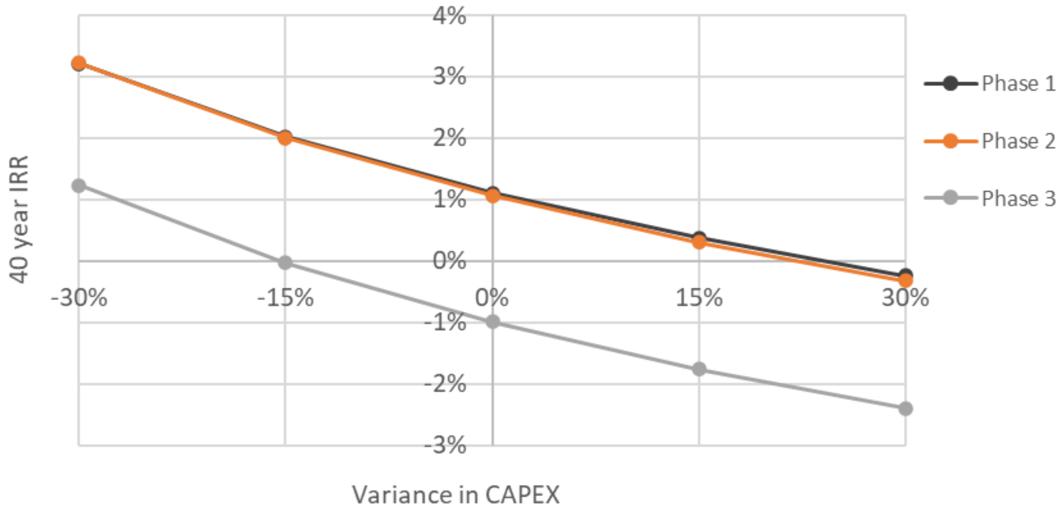

Figure 30: Variance in capital costs

8.2 Grant Funding

Table 24 shows the effect of GHNF and HNES grant funding on the 40 year IRR of the project. Grant funding has only been applied to phase 1 CAPEX items and assumes that the other phases do not receive any additional grant funding. If a grant of 40% from both GHNF (for energy centre CAPEX) and HNES (for secondary and tertiary side CAPEX) is received, an NPV of £0 under the assumed 4% discount rate will be achieved.

Table 24: Effect of GHNF and HNES grant funding on the 40 year IRR

Grant funding	40-year IRR Phase 1	Phase 2	Phase 3
No grant funding	1.1%	1.1%	-1.0%
GHNF 30%, HNES 0%	1.8%	1.7%	-0.4%
GHNF 40%, HNES 0%	2.1%	1.9%	-0.2%
GHNF 49%, HNES 0%	2.3%	2.1%	0.1%
GHNF 0%, HNES 30%	2.3%	2.1%	0.0%
GHNF 0%, HNES 40%	2.7%	2.5%	0.4%
GHNF 0%, HNES 49%	3.2%	2.9%	0.8%
GHNF 30%, HNES 30%	3.2%	2.9%	0.8%
GHNF 40%, HNES 40%	4.3%	3.8%	1.7%
GHNF 49%, HNES 49%	5.5%	4.8%	2.7%

8.3 Heat Demand

Figure 31 shows the effect of a variance in the total network heat demand for each phase, with all other parameters remaining constant. An increase in network heat demand has a positive effect on the 40 year IRR due to the increase in revenue from the residents.

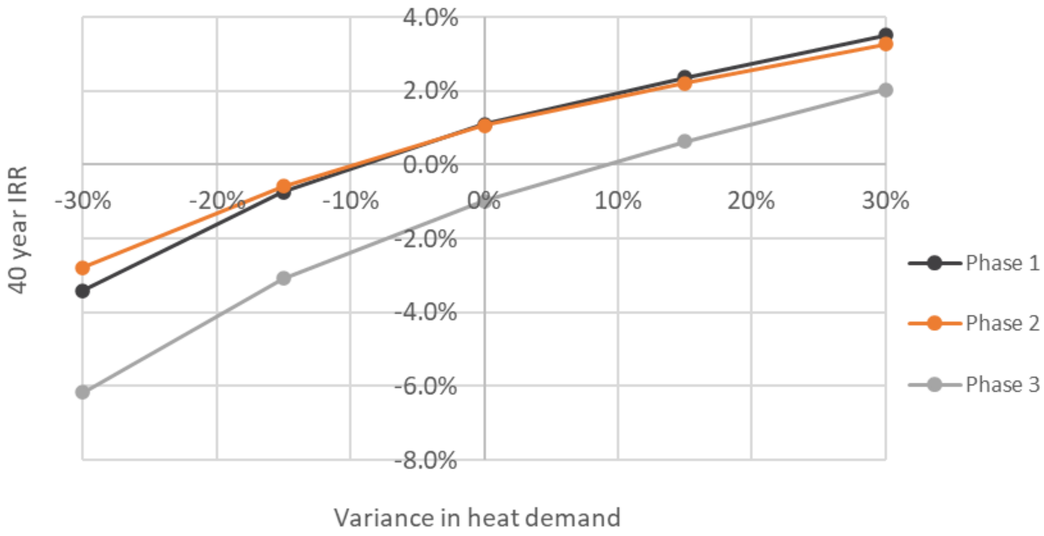

Figure 31: Variance in heat demand

8.4 Energy Tariffs

8.4.1 Energy Centre Gas Tariffs

Figure 32 shows the effect of a variance in gas purchase price for the energy centre. For the base case assessment, a gas tariff of 7.83 p/kWh has been used. An increase in gas prices will have a negative effect on IRR.

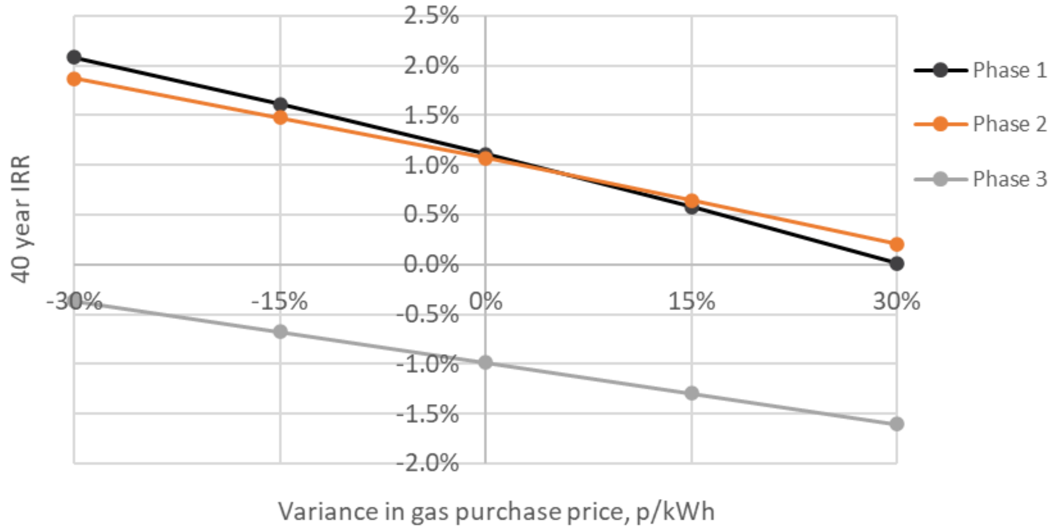

Figure 32: Variance in gas purchase price, p/kWh

8.4.2 Heat Sales Tariffs

Figure 33 shows the effect of a variance in heat sales tariff. It has been assumed as a base case that the variable element of the heat sales tariff for leaseholders will vary in line with the cost of fuel at the energy centre.

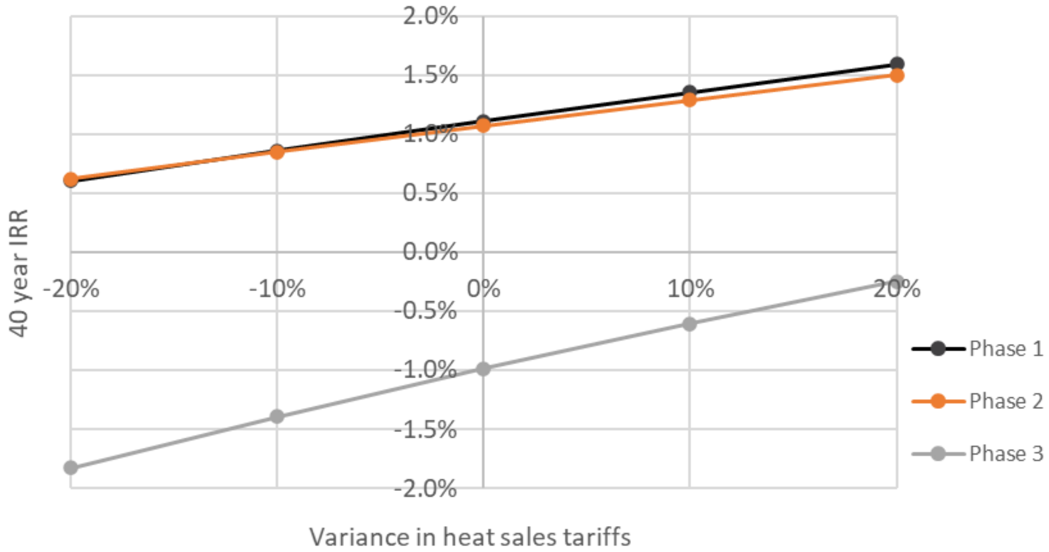

Figure 33: Variance in heat sales tariffs

8.4.3 Energy Centre Electricity Tariffs

Figure 34 shows the effect of a variance in electricity purchase tariff for the energy centre. For the base case assessment, 31.60 p/kWh for day and 31.05 p/kWh night electricity tariff has been used.

This has only a small effect on the phase 1 and 2 economics due to the electricity generated from the gas CHP. There is a significant impact of increase electricity tariffs in phase 3 as the gas CHP is removed and all of the energy centre electricity demand is imported from the grid.

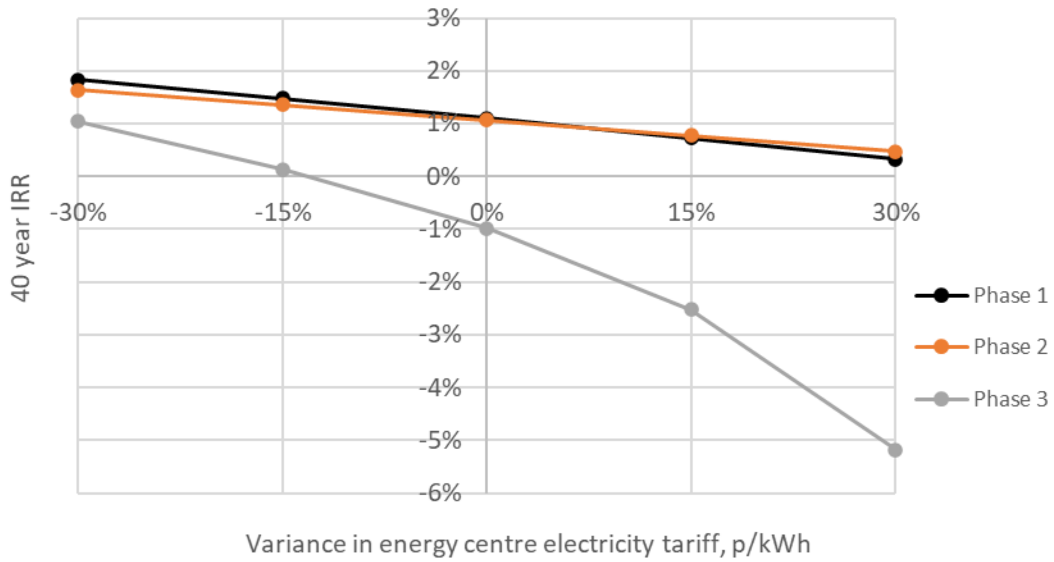

Figure 34: Variance in electricity purchase price, p/kWh

8.5 Energy Price Indexing

The effect of price indexing on all energy tariffs is shown in Table 25. If tariffs are indexed at a fixed rate, this reduces the 40-year IRR for all phases.

Table 25: Effect indexing on all energy tariffs

Indexing for energy tariffs	40-year IRR Phase 1	 Phase 2	 Phase 3
BEIS central scenario	1.1%	1.1%	-1.0%
BEIS low scenario	1.8%	1.6%	-0.4%
BEIS high scenario	-1.7%	-0.9%	-2.9%
Fixed rate: 0 %	Less than -10%	-7.0%	Less than -10%
Fixed rate: 2.5 %	Less than -10%	-7.7%	Less than -10%

8.6 Additional GSHP in Phase 3

A flexible heating solution has been designed for the scheme providing the potential to install an additional GSHP in phase 3, if it is economically viable at that stage. Table 26 shows the effect of installing a GSHP in phase 3 under current price projections.

Table 26: Effect of installing additional GSHP in phase 3

	Phase 3	Phase 3 with additional GSHP installed
Additional GSHP capacity	-	500 kW
Heat demand met by low carbon technology	87%	98%
IRR	-1.0%	-2.6%
NPV	-£3,716,589	-£4,293,734
Social IRR	11.2%	11.1%
Social NPV	£9,159,558	£9,038,898

8.7 Sensitivity Summary

Key sensitivity parameters for the prioritised network areas include:

- Capital costs

- Network heat demand
- Energy tariffs including heat sales tariffs, energy centre fuel purchase tariffs and indexation of energy tariffs
- Grant funding

9 RISKS AND ISSUES

The main risks and constraints for the implementation of the proposed district heating network options have been considered and assessed. Table 28 outlines potential risks and issues that apply to all networks including both current risk and re-scored values.

Risk ratings are the product of impact and likelihood. The impact measures how much of an affect the risk being realised would have, and the likelihood is a measure of how probable the risk realisation is. The score associated with current risk is the level of risk present if no further action is taken, and re-scored risk levels are a measure of the risk present once the mitigating measures have been carried out.

A key showing the level of risk is shown in Table 27.

Table 27: Risk level key

Impact	1	Insignificant
	2	Minor
	3	Moderate
	4	Major
	5	Catastrophic
Likelihood	1	Highly unlikely, but may occur in exceptional circumstances
	2	Not expected, but a slight possibility it may occur
	3	Might occur at some time
	4	There is a strong possibility of occurrence
	5	Very likely, expected to occur
Risk rating	0-5	**Low risk**
	6-14	**Medium risk**
	15-25	**High risk**

Table 28: Risk register

	Risk / issue	Risk rating: Impact	Likelihood	Rating	Rationale	Mitigating measure / action
Energy demand assessment	**ED1** Heat demand data only available at substations.	Risk rating: 4	4	16	Heat demand data is currently metered at the building substations which include the secondary side losses and the heat demands from the dwellings. However, only the heat used at the dwellings will be paid for by the residents, therefore an overestimation or underestimation of the heat demands could significantly impact network revenue and overall viability.	A detailed heat loss assessment was undertaken to estimate the breakdown of the heat losses and the heat demand on the secondary side of the network. With the heat losses removed from the overall substation data, the heat demand at the dwellings was determined and used to calculate network revenue.
		Mitigated risk rating: 4	2	8		
	ED2 Half hourly gas data not available for all sites	Risk rating: 4	3	16	Heat demand profiles are used to determine the technology sizing requirements of the network and have a significant impact on technical and economic viability assessments of the proposed network.	Half hourly data was available for most buildings. For those without data (Cooks Road, Jack Hobbs, Brandon Library), the hourly, daily and annual heat demand of buildings has been modelled based on building use, occupancy / heating patterns and local temperature data. The consultant team has a database of hourly annual demand profiles for a wide range of building types and these are used to provide and estimated heat demand profiles for buildings where half hourly data has not been obtained.
		Mitigated risk rating: 4	1	4		
Energy centre	**EC1** The visual impact of the energy centre or abstraction is deemed significant.	Risk rating: 4	2	8	If the visual impact was deemed significant, this could potentially increase design costs or limit the GSHP capacity.	Changes to the externals of the existing energy centre will be limited to the installation of a thermal store and a small flue and cooler for the gas CHP. The thermal store has been sized to ensure it is no taller than the existing energy centre building to minimise its visual impact.
		Mitigated risk rating: 4	1	4		
	EC2 Heat pump refrigerant working fluid requires consideration	Risk rating: 4	4	16	R134a has a high GWP (global warming potential) and may increase in cost as a result of the Kigali amendment. If ammonia or HFOs are used then there is a safety risk that needs to be mitigated through design and operation.	Refrigerant choice needs to be considered in design measures and risk assessments as the project progresses. The data for a heat pump using propane and isobutane has been used in the heat pump sizing process and CoP calculations.
		Mitigated risk rating: 4	2	8		

	Risk / issue	Risk rating			Rationale	Mitigating measure / action
		Impact	Likelihood	Rating		
Energy centre	**EC3** Abstraction flow rates from aquifer are lower than assumed	Risk rating 4	 3	 12	If the water availability from the aquifer is lower than the 15 l/s assumed in this assessment, an additional borehole could be required to meet the network heat demand and lead to a significant increase in CAPEX.	Water abstraction limits at the other LBS housing estates are set at 19.5 l/s. A conservative 15 l/s was assumed in this assessment to ensure scheme viability at lower flow rates. The operational data from the boreholes at other LBS estates suggest that the maximum flow rate available is even higher than the 19.5 l/s set by the EA and therefore the likelihood of flowrates lower than 15 l/s is low. The drilling of a trial borehole could further reduce the risk should it be required.
		Mitigated risk rating 4	 2	 8		
	EC4 Emissions from gas CHP flue near residential blocks	Risk rating 4	 3	 12	Should the location of the proposed flue be in too close to the nearby housing blocks and negatively affect the air quality of the surrounding area, additional emissions abatement measures will be required that would increase project CAPEX.	The gas CHP flue has been designed to ensure it is located at the furthest point from the neighbouring housing blocks. However, dispersion modelling should be undertaken to identify any potential impacts from the gas CHP emissions. If the impact is deemed significant, a flue dilution system should be installed to mitigate this.
		Mitigated risk rating 4	 1	 4		
	EC4 Energy centre maintenance access below ground level	Risk rating 3	 3	 9	Consideration need for installation and maintenance access for large equipment items such as heat pump, thermal store and gas CHP.	The technology has been sized to ensure ease of installation and maintenance access. Site surveys have been completed to confirm there is sufficient space.
		Mitigated risk rating 3	 1	 3		
Heat network and connections	**N1** Existing network is oversized	Risk rating 3	 3	 9	The oversizing of the network is resulting in low velocities throughout the pipework. This could lead to a buildup of sediments in the pipe.	More regular maintenance and cleaning of the pipework may be required to ensure the network operates efficiently.
		Mitigated risk rating 3	 2	 6		
	N2 Borehole pipework will cross existing heat network route	Risk rating 4	 3	 12	Additional considerations will be required to avoid the existing heat network pipework. This could lead to increased capital costs.	Digging and installing the borehole connecting pipework deeper underground to avoid the existing heat network pipework may be required. The costs for this have been considered in the economic assessment.
		Mitigated risk rating 4	 2	 8		

	Risk / issue	Risk rating			Rationale	Mitigating measure / action
		Impact	Likelihood	Rating		
Economic assessment	**EA1** Capital costs are significantly higher than estimated.	Risk rating 5	 4	 **20**	Higher capital costs can have a significant impact on the viability of all network phases. If the economic assessment does not include robust project CAPEX, the likely financial benefits or does not provide sufficient information to secure funding, then the network plan will not progress.	All project costs have been based on a combination of quotes from potential suppliers or previous project experience. The consultant team have a large database of actual costs of installing district energy schemes including costs for equipment supply and installation, distribution pipework supply and installation, trench excavation and re-instatement. Sensitivity analysis has been undertaken for network options to show the effect of a variance in capital costs, shown in section 8.1. Contingency has been applied to all CAPEX items.
		Mitigated risk rating 5	 2	 **10**		
	EA2 Variation in heat sales tariffs significantly affects economics.	Risk rating 5	 4	 **20**	A variation in the heat sales tariffs has a significant impact on the viability of all network options.	Heat sales tariffs are calculated based on LBS' borough wide methodology. LBS should ensure that the heat sales tariffs vary in line with the energy centre operating costs. Sensitivity analysis has been undertaken to show the effect of heat sale tariff variation, shown in section 8.4.2.
		Mitigated risk rating 5	 2	 **10**		
	EA3 The scheme requires grant funding to reach an NPV of £0.	Risk rating 5	 5	 **25**	The phase 1 scheme is unlikely to reach a 40 year NPV of £0 without GHNF or HNES.	The scheme has been designed to meet the GHNF eligibility criteria. The impact of grant funding is shown in section 8.2.
		Mitigated risk rating 5	 4	 **20**		
	EA4 Variation in electricity import tariffs significantly affects economic viability.	Risk rating 5	 4	 **20**	Variation in electricity import tariffs have a significant impact on the viability of network options.	Import tariffs have been based on current tariffs the Brandon energy centre. A small gas CHP has been included in the design of the scheme to reduce the requirements for electricity import. Sensitivity analysis has been undertaken to show the effect of electricity import tariff variation, shown in section 8.4.3.
		Mitigated risk rating 5	 3	 **15**		

	Risk / issue	Risk rating			Rationale	Mitigating measure / action
		Impact	Likelihood	Rating		
General	**G1** Senior stakeholders do not support the scheme and / or the scheme is not linked to corporate priorities.	Risk rating 5	 4	 **20**	There is a risk that senior management and elected members will not fully support the project. If this is the case, then the whole project viability could be affected. Senior management and elected member engagement are key to advance the project further.	The proposed scheme is in line with the CSFs and supports LBS' ambition to decarbonise and reach net zero by 2030. Further stakeholder engagement will be needed as the project progresses.
		Mitigated risk rating 5	 3	 **15**		
	G2 Leaseholder and tenants do not support the scheme	Risk rating 5	 4	 **20**	The project is unlikely to progress if there is significant opposition from both tenants and leaseholders.	The project results in lower annual heat costs for both leaseholders and tenants. The upgrades to the scheme also result in lower network losses and lower annual running costs. These cost savings are passed on to the leaseholders who will see a direct benefit to the improved network. Further stakeholder engagement will be needed as the project progresses.
		Mitigated risk rating 5	 2	 **10**		

10 CONCLUSIONS

This report presents the findings of the Brandon Estate Ground Source Heat Pump (GSHP) Feasibility study, prepared for the London Borough of Southwark (LBS).

Energy Demand Assessment

Brandon Estate is made up of 10 housing blocks and a total of 558 dwellings. The blocks are currently connected to a heat network at the site which is supplied by gas boilers. Two commercial buildings are also connected to the network; Brandon Library and Jack Hobbs Community Centre.

Heat usage at the site is metered at the substations that supply each housing block. A heat loss assessment was completed to identify the heat demand at the dwellings and the secondary side building losses. This concluded that the secondary networks currently experience extremely high heat losses, and the 6-pipe riser and lateral networks should be reconfigured to a 2-pipe system utilising the existing DHW system. This alongside tertiary upgrades at the dwellings including HIUs, new radiators and copper pipework, will reduce network return temperatures and losses, and increase the scheme's efficiency. The secondary side networks should be replaced in the medium term to further improve the network efficiency.

Energy Centre and Network Assessment

The proposed scheme will utilise the existing energy centre at Brandon Boiler House and the existing heat network pipes, as there is sufficient space in the existing energy centre to incorporate new generation plant and associated equipment and the heat network has recently been replaced.

Proposed Solution

A prioritised heat generation solution of modular GSHPs and a small gas CHP unit has been identified for the Brandon Estate. This solution will minimise energy centre OPEX through the supply of electricity from the gas CHP to one of the GSHPs and reduce the risk relating to highly volatile energy prices. The proposed scheme will also maximise the CO_2e savings in the short term as the CO_2e intensity of electricity generated from the gas CHP is lower than the grid. However, as the grid continues to decarbonise, minimising the electricity generated from the gas CHP will result in greater CO_2e savings. Therefore, it is proposed that the gas CHP is removed from the energy centre once it reaches its end of life (15 years) to allow a greater proportion of heat to be met by the GSHPs. The proposed solution is flexible with the potential for an additional GSHP to be installed in the future, should this be beneficial due to energy prices and CO_2e intensity.

The three phases proposed for the scheme are:

- Phase 1: GSHP and gas CHP installed alongside upgrades to commercial and dwelling heating systems
- Phase 2: Risers and laterals within housing blocks are replaced
- Phase 3: Gas CHP is removed at the end of its lifetime

<table>
<tr><th></th><th>Phase 1</th><th>Phase 2</th><th>Phase 3</th></tr>
<tr><td>Network year</td><td>2025</td><td>2035</td><td>2040</td></tr>
<tr><td>Building heat demand (not including network losses)</td><td colspan="3">5,414 MWh</td></tr>
<tr><td>Total network heat demand (including network losses)</td><td>7,236 MWh</td><td colspan="2">6,253 MWh</td></tr>
<tr><td>Peak heat demand</td><td>2.2 MW</td><td colspan="2">2.1 MW</td></tr>
<tr><td>GSHP capacity</td><td colspan="3">1 MW</td></tr>
<tr><td>Gas CHP capacity</td><td colspan="2">200 kWe/252 kWth</td><td>-</td></tr>
<tr><td>Total low carbon capacity</td><td colspan="2">1.25 MW</td><td>1 MW</td></tr>
<tr><td>Heat demand met by heat pumps, gas CHP and thermal store</td><td>6,661 MWh</td><td>5,883 MWh</td><td>5,444 MWh</td></tr>
</table>

	Phase 1	Phase 2	Phase 3
Heat demand met by peak and reserve boilers	575 MWh	369 MWh	809 MWh
% heat demand met by low carbon / renewable technology	92 %	94 %	87 %

Economics

The 40 year economics (with and without leaseholder charges and grant funding), and carbon savings of the network are summarised below.

	Phase 1	Phase 2	Phase 3
Capital costs for each phase (including contingency)	£6,452,116	£1,191,908	-
Total cumulative capital costs (including contingency)		£7,664,024	£7,664,024
40 year IRR	1.1%	1.1%	-1.0%
40 year NPV	-£2,440,704	-£2,726,292	-£3,716,589
40 year IRR with leaseholder contributions	2.7%	2.7%	0.7%
40 year NPV with leaseholder contributions	-£934,194	-£1,037,894	-£2,028,191
40 year IRR with 35% GHNF, 49% HNES funding	4.7 %	4.1%	2.1%
40 year NPV with 35% GHNF, 49% HNES funding	£370,221	£84,633	-£905,664
40 year social IRR	11.7%	11.4%	11.4%
Lifetime carbon savings (40 years)	72,181	75,331	80,336

Under the agreed assumptions, the network will require grant funding to reach LBS' CSF of a 40 year NPV of £0. There is potential for the scheme to be supported through the GHNF for the energy centre CAPEX and the HNES for the secondary and tertiary side upgrades. The proposed scheme will also result in an annual OPEX saving of approximately £500,000 (39%) based on the current network operation.

Sensitivity and Risk

Key sensitivity parameters for the prioritised network include:

- Energy tariffs including heat sales tariffs, energy centre fuel purchase tariffs and indexation of energy tariffs
- Capital costs
- Heat demand
- Grant funding

Key risks for the network include:

- Phase 1 likely to require grant funding to be economic
- Abstraction flow rates from the aquifer are not confirmed but are highly likely based on existing nearby boreholes
- Pipework connecting the boreholes to the energy centre will cross existing heat network pipework which may lead to more complicated digging requirements
- Leaseholders may oppose the development of the new scheme however, this should be mitigated as the scheme reduces the annual cost of heat to residents

Summary and Next Steps

It is likely that the scheme will require grant funding to meet LBS' CSF of £0 40 year NPV and deliver the required project benefits.

- Further assess pipework connecting boreholes where it crosses the existing heat network
- Continued discussions with local DNO to ensure electricity connection
- Submit application for GHNF grant funding
- Submit application for HNES funding

APPENDIX 1: ENERGY DEMAND ASSESSMENT

Table 29 summarises the network connections, the number of tenants and leaseholders per housing block, and the annual and peak heat demands.

Table 29: Energy loads

Ref	Building Name	Tenants	No. dwellings Leaseholders	Total	Heat demand, kWh	Peak demand, kW
1	Bateman House	52	16	68	667,323	238
2	Brawne House	54	14	68	667,323	238
3	Cooks Road	3	-	3	33,346	22
4	Cornish House	49	19	68	595,309	255
5	Cruden House	55	13	68	595,309	255
6	Maddock Way and Molesworth House	52	20	72	701,675	376
7	Morton House	23	16	39	408,919	281
8	Napier House	27	9	36	217,510	97
9	Prescott House	53	13	68	667,323	238
10	Walters House	53	13	68	595,309	255
11	Brandon Library		N/A		103,150	234
12	Jack Hobbs Community Centre		N/A		109,555	164

Heat Loss Calculations

Below are the calculations used to estimate the heat losses in the risers, laterals, valves, and flanges in the existing space heating circuits within buildings.

Equation for heat loss in risers:

Heat Loss = Insulated Pipe Losses (W/m/K) * Length of each Riser (m) * Number of Risers * dT (K)

Equation for heat loss in laterals:

Heat Loss = Insulated Pipe Losses (W/m/K) * Length of each Lateral (m) * Number of Laterals * dT (K)

Equation for heat loss in valves:

Heat Loss = Uninsulated Pipe Losses (W/m) * Length of each Valve (m) * Number of Valves

Equation for heat loss in flanges:

Heat Loss = Uninsulated Pipe Losses (W/m) * Length of each Flange (m) * Number of Flanges

dT was assumed to be 65 K and the length of both valves and flanges was assumed to be 1 m each.

APPENDIX 2: KEY PARAMETERS AND ASSUMPTIONS

Energy Tariffs

The heat sales tariffs for this assessment have been calculated using LBS' methodology for leaseholders. The borough wide tenant heat sales tariffs have also been used and are shown in Table 30.

Table 30: LBS borough wide tenant heat tariffs

No.	Including VAT at 5%	
bedrooms	Standing charge, £/day	Unit rate, p/kWh
0	0.47	11.56
1	0.51	
2	0.56	
3	0.60	
4	0.64	

The LBS methodology for calculating leaseholder heat tariffs are shown in Table 31 and the tariffs are shown in Table 32

Table 31: Leaseholder heat tariff calculation

	Phase 1	Phase 3
Energy centre fuel usage	4,957,376	3,072,717
Annual energy centre fuel costs	£542,623	£751,346
Energy centre fuel costs	10.95 p/kWh	24.45 p/kWh
Heat demand from connections	5,414,204	5,414,204
System efficiency	109%	176%
Variable charge excl VAT, p/kWh	10.02	13.88
Variable charge incl VAT @5%, p/kWh	10.52	14.57

Table 32: Leaseholder heat tariffs

No.	Including VAT at 5%		
bedrooms	Standing charge, £/day	Phase 1 and 2 unit rate, p/kWh	Phase 3 unit rate, p/kWh
0	0.48	10.52	14.57
1	0.51		
2	0.54		
3	0.57		
4	0.61		

Energy Centre Tariffs

Gas and electricity purchase tariffs for the energy centre have been based on current energy tariffs for the existing Brandon energy centre. CCL has not been included as LBS are not required to pay it. For gas, a tariff of 7.83 p/kWh and a gas standing charge of £75.27 /day have been used. A day electricity tariff of 31.60 p/kWh and night electricity tariff of 31.05 p/kWh have been used.

Key Technology Parameters

Key technology parameters for the network are shown in Table 33.

Table 33: Technical inputs

Parameter	Value	Source of data / assumption
SPF_{H1} for heat pump	Various	Varies for each network phase derived from manufacturers performance curves based on the selected heat pump, potential water conditions for the site and required network temperatures.
Gas CHP modulation limit	50%	Modulation limit based on gas CHP capacities and modulation limits provided in manufacturers specifications.
Gas CHP seasonal heat efficiency	45.8%	Average seasonal heat efficiency calculated in SE technology sizing tool based on efficiencies provided in manufacturer's specifications and CHP modulation.
Gas CHP seasonal power efficiency	36.3%	Average seasonal power efficiency calculated in SE technology sizing tool based on efficiencies provided in manufacturer's specifications and CHP modulation.
Availability of heat from heat pump	50 weeks	The base case assessed assumes 2 weeks plant downtime a year. It has been assumed that half the downtime will occur from the first week of January and half the downtime from the first week of July.
Availability of heat from gas CHP	50 weeks	The base case assessed assumes 2 weeks plant downtime a year. It has been assumed that half the downtime will occur from the first week of January and half the downtime from the first week of July.
Peak and reserve boiler efficiency	90%	Expected efficiency of gas boilers based on experience of operating plant.

Technology replacement costs have been calculated on an annualised basis and take into account the expected lifetime of the technology, fractional repairs and the length of the business term. Plant / equipment lifetimes are shown in Table 34.

Table 34: Plant and equipment lifetime

Plant / equipment	Lifetime
Heat pumps	20 years
Gas CHP	15 years
Peak and reserve boilers	30 years
Customer building connections	20 years

OPEX

The operating expenditure projections for all phases is shown in Table 35.

Table 35: Operating expenditure

	Phase 1	Phase 2	Phase 3
Input fuel costs for gas CHP	£286,681	£260,005	-
Input fuel costs for gas peak and reserve boilers	£50,004	£32,109	£70,373
Gas standing charge	£27,474	£27,474	£27,474
Import electricity costs for heat pump, electric boilers, energy centre and network pumps	£206,821	£169,070	£683,605
Electricity standing charge	£10,126	£67	£67
Gas CHP maintenance and service costs	£14,449	£14,449	-
Heat pump maintenance and service costs	£25,000	£25,000	£25,000
Gas peak and reserve boilers maintenance and service costs	£1,724	£1,107	£2,427
Heat network monitoring and maintenance (including pipework and HIUs/substations)	£16,830	£16,830	£16,830
Staff costs	£40,000	£40,000	£40,000
Metering and billing	£67,903	£67,903	£67,903
Insurance	£25,000	£25,000	£25,000

CAPEX

The capital expenditure is shown in Table 36.

Table 36: Capital expenditure

	CAPEX (not incl. contingency)		Contingency	CAPEX (incl. contingency)	
	Phase 1	Phase 2		Phase 1	Phase 2
Further project development (e.g. professional fees, legal, design, surveys, etc.)	£388,655	-	10%	£427,520	-
Contractor costs for preliminaries, project management and design	£259,103	-	10%	£285,014	-
Heat pump	£500,000	-	10%	£550,000	-
Cost of accessing the heat source (e.g. boreholes, abstraction platform etc…)	£232,143	-	15%	£266,964	-
Heat pump M&E	£125,000	-	20%	£150,000	-
Pressurisation	£25,000	-	10%	£27,500	-
Water treatment	£15,000	-	10%	£16,500	-
Main district heat network pumps	£30,000	-	10%	£33,000	-
Controls	£75,000	-	20%	£90,000	-
Other energy centre M&E	£108,750	-	10%	£119,625	-
Thermal store(s)	£27,000	-	10%	£29,700	-
Electricity grid connection	£135,600	-	10%	£149,160	-
Cost of secondary side improvements	£3,588,863	£1,083,553	10%	£3,947,749	£1,191,908
Gas CHP plant (purchase & install)	£179,639	-	10%	£197,603	-
Gas CHP emission abatement	£70,000	-	20%	£84,000	-
Gas CHP M&E	£63,051	-	10%	£69,356	-
Gas CHP flues	£7,020	-	20%	£8,424	-
Total	**£5,829,824**	**£1,083,553**		**£3,947,749**	**£1,191,908**

Revenue

The revenue projections for phases 1 and 2 are shown in Table 37.

Table 37: Revenue

	Ownership	Phase 1	Phase 2	Phase 3
Fixed heat tariff revenue	All	£116,222	£116,222	£116,222
Variable heat tariff revenue - industrial	LBS	-	-	-
Variable heat tariff revenue - residential	LBS	£450,523	£450,523	£450,523
Variable heat tariff revenue - commercial / services	LBS	£22,866	£22,866	£22,866
Variable heat tariff revenue - industrial	Private	-	-	-
Variable heat tariff revenue - residential	Private	£137,206	£137,206	£190,043
Variable heat tariff revenue - commercial / services	Private	-	-	-
Total		£726,817	£726,817	£779,654

Price Projections

To assess the impact of expected future price changes on the financial outputs, the central scenario price projections for natural gas and electricity have been used (last updated April 2023). The projected changes in prices for electricity and natural gas for residential, services and industrial is illustrated in Table 38. The projected price variations have been applied to the energy tariffs calculated as discussed in section 6.4.

The fossil fuel price projections (central scenario) are shown in Table 38.

Table 38: Fossil fuel price projections

	Sector	Units	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Electricity	Industrial	p/kWh	26.8	20.9	11.9	11.3	11.2	10.9	11.1	11.1	11.2	11.1	11.2	11.6	11.7
	Residential	p/kWh	41.7	40.3	34.8	22.3	21.3	20.7	20.7	20.6	19.7	19.8	20.1	20.4	20.2
	Services	p/kWh	29.0	23.0	13.8	13.2	13.0	12.7	12.8	12.7	12.7	12.6	12.6	13.0	13.1
Natural gas	Industrial	p/kWh	8.2	5.6	2.5	2.2	2.3	2.3	2.3	2.4	2.4	2.5	2.5	2.5	2.6
	Residential	p/kWh	11.3	11.2	8.6	5.2	4.9	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.1
	Services	p/kWh	8.9	6.4	3.3	3.0	3.1	3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.4

CO_2e Emissions Factors

The electricity grid CO_2e emissions figures used in assessments are shown in Table 39.

Table 39: Electricity grid CO_2e emissions

Electricity grid CO_2e emissions, gCO_2e/kWh				Electricity grid CO_2e emissions, gCO_2e/kWh			
Year	LCP marginal	IAG marginal (commercial)	IAG marginal (domestic)	Year	LCP marginal	IAG marginal (commercial)	IAG marginal (domestic)
2023	382.8	244.0	248.5	2037	250.0	27.3	27.8
2024	381.1	227.2	231.4	2038	248.9	22.7	23.1
2025	381.2	209.2	213.1	2039	249.5	18.9	19.3
2026	382.0	189.9	193.4	2040	243.4	15.7	16.0
2027	367.9	169.3	172.4	2041	239.3	15.0	15.3
2028	359.2	147.2	150.0	2042	249.0	14.2	14.5
2029	333.8	123.6	125.9	2043	246.9	9.0	9.1
2030	311.9	98.3	100.1	2044	228.7	8.3	8.5
2031	316.1	81.9	83.4	2045	228.7	7.7	7.9
2032	293.0	68.2	69.4	2046	228.7	7.6	7.7
2033	279.5	56.7	57.8	2047	228.7	5.2	5.3
2034	260.0	47.2	48.1	2048	228.7	5.1	5.2
2035	248.3	39.3	40.1	2049	228.7	3.2	3.3
2036	263.8	32.8	33.4	2050	228.7	2.5	2.5

Table 40: Natural gas CO_2e emissions

Parameter	Value
Natural gas CO_2e emissions factor, gCO_2e/kWh	182.6
Average efficiency for BAU gas boilers including network losses	44%

APPENDIX 3: TECHNOLOGY SIZING

Energy generation technologies are assessed using in house software that has been developed to allow detailed sizing of plant and thermal storage, modelling of operating parameters and conditions, financial assessment and sensitivity analysis. The software utilises hourly network demands for each day of the year and considers hourly energy outputs from low carbon technologies, thermal storage and peak and reserve plant taking into account modulation limits, efficiencies and plant down time for maintenance. A range of plant and thermal store sizes and number of units are assessed and optimised to ensure key operating and financial/investment criteria are met.

The tools consider:

- Heat and electricity demand that can be served by the plant (including private wire options)
- Thermal storage - used to supply heat loads below modulation limits or peaks above plant capacity and minimise plant firing e.g. for gas CHP store size will be modelled, optimised and cost/benefit analysis conducted to consider the optimum operating strategy in relation to both heat and electricity generation
- Supply strategy - consideration of issues such as varying seasonal or diurnal operation, continuous operation, modulated or full output, primary energy source or base load only and peak and reserve plant requirement
- Peak and reserve boiler sizing - according to the diversified peak demand of the various network phases, predicted operating requirements and redundancy
- Peak supply and minimum load - this will consider plant modulation limits and the number of units
- Carbon savings - these will be calculated against the 'business as usual' case and include annual and lifetime savings based on the most up to date BEIS carbon emissions projections

The GSHP for the network has been sized based on potential abstraction rates from the aquifer and network heat demand. The GSHP capacity has been maximised to provide the greatest CO_2e savings for the network to and allow for affordable heat to residents.

The gas CHP engine for the network has been sized using SE's technology sizing tool to supply the GSHP with electricity and to provide the optimum balance between heat and electricity generation capacity, capital cost, maintenance costs and physical size.

The technical model used to optimise the CHP schemes prioritises heat supply over power generation i.e. there is no heat dumping from the CHP scheme. The gas CHP engines and thermal stores have been sized with consideration of the hourly annual network heat demand, availability of heat from the GSHP, electricity demand of the GSHP and thermal store capacity and levels. Peak and reserve gas boilers will meet any remaining demand. Technology sizing is based on an iterative process within the technical model to identify the optimal balance of the priorities.

Figure 35 shows an example output from our CHP sizing tool for the phase 1 network served by the 1 MW WSHP and 252 kWth gas CHP. The load duration curve shows the phase 1 heat demand for every hour of a year, ordered from highest to lowest. The grey line shows the gas CHP capacity for phase 1 and black line shows the total low carbon and renewable capacity installed. The heat demand above the black line is met by thermal storage and peak and reserve boilers.

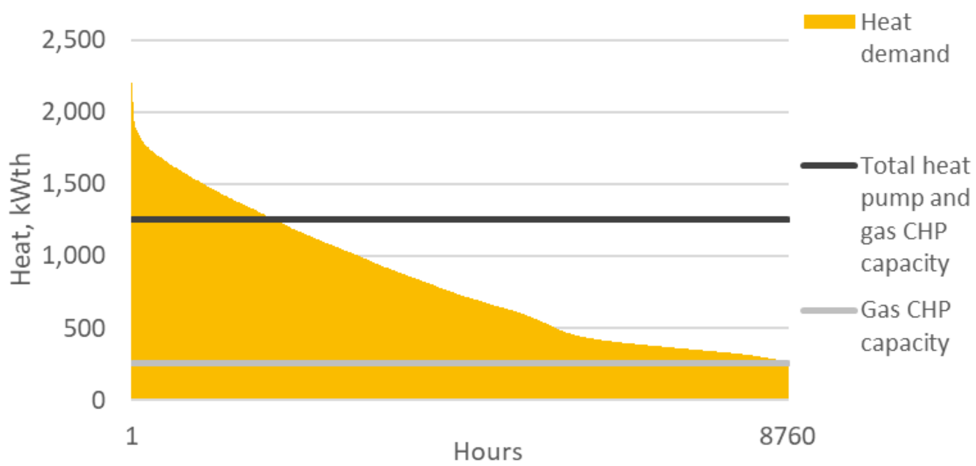

Figure 35: Load duration curve for example network

Numerous sizes and numbers of units of gas CHP engines were assessed for the network alongside the 1 MW GSHP. The engine was selected based on technical and economic viability as well as LBS's key priority for the network to reduce carbon emissions.

Figure 36 and Figure 37 show the proportion of the heat demand supplied by the GSHP, gas CHP engine, charge and depletion of the thermal store and heat demand supplied by peak and reserve boilers for the phase 1 network for 1st and 2nd January and 1st and 2nd August respectively. The GSHP, gas CHP engines and thermal stores meet the majority of the baseload heat demand with a small proportion of the demand met by peak and reserve boilers. Where the thermal store charge and depletion is greater than the total heat demand shown in Figure 36 and Figure 37, the thermal store is being charged. Where the thermal store charge & depletion is below the total heat demand, the thermal stores are being depleted.

Table 41: Annual heat generated by each technology

Annual heat supplied to network from WSHP and thermal store, MWth	4,999
Annual heat supplied to network from gas CHP and thermal store, MWth	1,662
Annual heat supplied to network from peak and reserve boilers, MWth	575

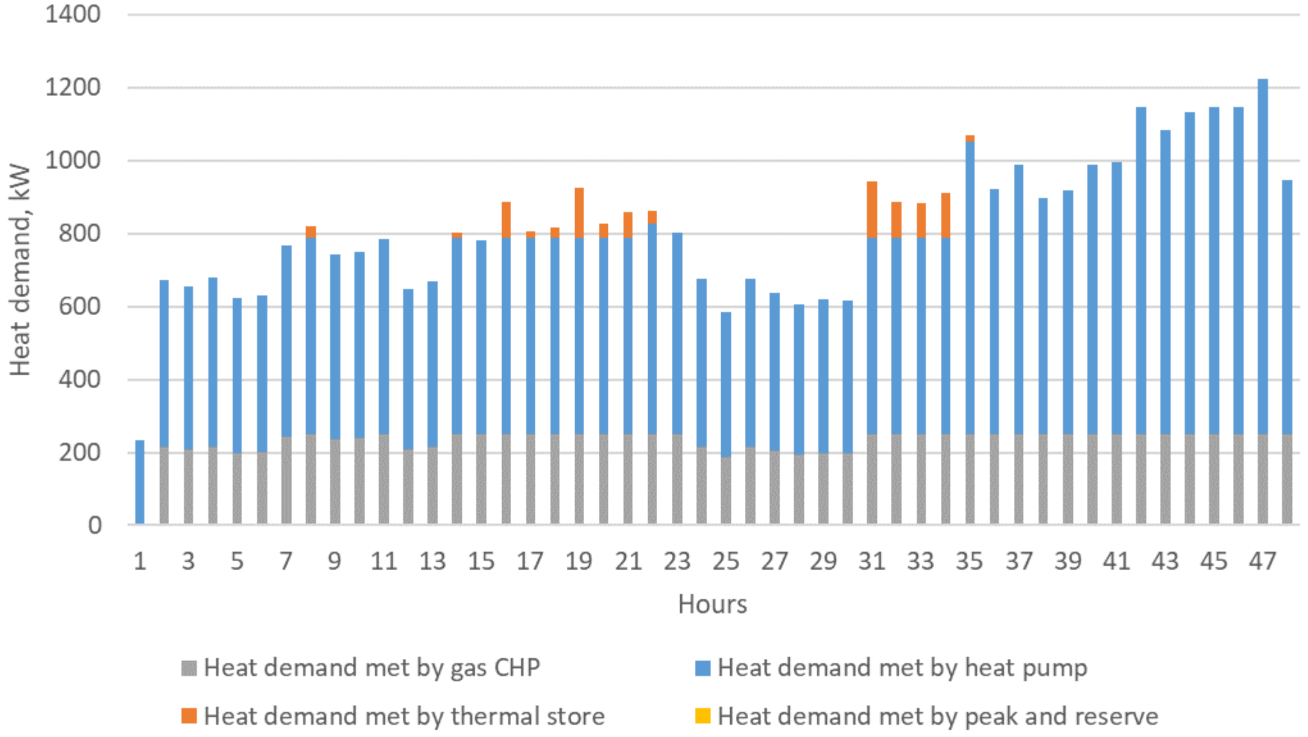

Figure 36: Heat generation 1st and 2nd January

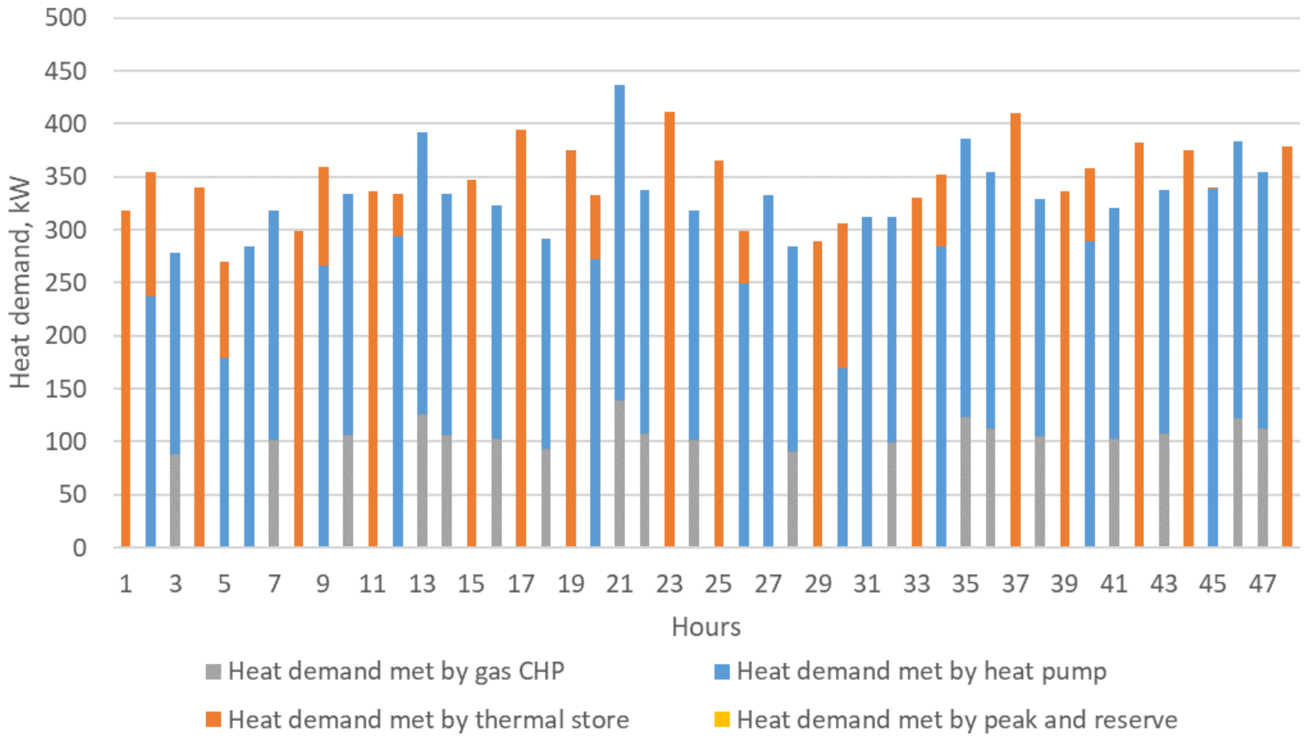

Figure 37: Heat generation 1st and 2nd August