DECARBONISING COMMUNAL HEATING

Report for: SEAI

Viability of Replacing Gas Fuel Sources in Communal Heating Systems with a Geothermal Energy Source.

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Sustainable Energy Authority of Ireland

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ACCRONYMS

ASHP	Air Source Heat Pump
BAU	Business as Usual
BEMS	Building Energy Management System
CHP	Combined Heat and Power
COP	Coefficient of Performance
DHW	Domestic Hot Water
DKIT	Dundalk Institute of Technology
GSHP	Ground Source Heat Pump
NOx	Nitrous Oxides
NMVOCs	Non-methane volatile organic compounds
OH &P	Overheads and Profit
PM	Project Management
PM2.5	Particulates, 2.5 micrometres in diameter
sCOP	Seasonal Coefficient of Performance
SOx	Sulphur Oxides
TEM	Techno-economic model
TRT	Thermal response test
WSHP	Water Source Heat Pump

UNITS

degC	Degrees Celsius
kW	Kilowatts
kWh	Kilowatt-hours
MW	Megawatt-hours
MWh	Megawatt-hours

NOTATION

In this report negative numbers in tables and figures are depicted using parenthesis:

i.e., (200) = -200

EXECUTIVE SUMMARY

Project scope & site details

High commercial energy prices for operators of district or communal heating networks has meant that there have been sharp increases in the heat sale price for many customers on these networks due to a passing through of costs. One of the main aims of a heat network is to deliver heat to customers at as low a heat sale price as any counterfactual solution (i.e., individual heating solutions).

This has not been the case in recent years with homes and businesses experiencing unprecedented energy price increases partially offset by price support mechanisms such as electricity credits and VAT reductions resulting in less pronounced increases on domestic gas rates than for commercial. In relation to household gas prices, the effective unit prices increased by ~37% between January and June 2022, with an increase in household electricity prices of ~16%.[1]

The focus of this study was to look at alternative low-carbon heating solutions for an existing communal heat network – with a primary scenario to be evaluated being the potential for the utilisation of shallow geothermal heat on the network. Heat pumps and geothermal heat sources were identified in the National Heat Study as being a suitable heating technology for communal heating systems. This, plus trying to keep the heat sale price low for customers was a key element of this project.

The heat network that was chosen for this study is the Carlinn Hall communal heat network, located at the southern end of Dundalk, County Louth (Figure 5). The system supplies heat to approximately 178 domestic properties within a housing estate, which was constructed over several phases between 2007-2018. The properties on this heat network were all built to be low-energy (surpassing the building regulations at the time) standards. The system supplies heat to customers via buried heating circuits that originate from a central energy centre on the eastern side of the estate, and heat use is metered in each property via a heat interface unit (HIU). The heat is generated by gas-fired boilers and gas-fired combined heat and power (CHP) units.

The network is operated by an Owners Management Company (OMC) service provider that is covered by the MUD Act 2011[2] which limits contracts with providers of goods and services to a maximum of 3 years. This impacts contracts between the OMC and utility providers as well as the network O&M provider, reducing long-term investment potential.

Note: Figure numbers in this executive summary mirror that of the figure number within the body of the report

[1] https://www.seai.ie/data-and-insights/seai-statistics/key-statistics/energy-data/#comp00005c0fcbea00000088e671a3

[2] https://www.citizensinformation.ie/en/housing/owning_a_home/home_owners/management_companies_for_apartment_blocks.html

Figure 5: Carlinn Hall, neighbourhood © Maxar Technologies

The analysis of the operational data has been used to develop an understanding of existing energy consumption, network losses and hydraulic efficiency. This analysis provides an insight into the opportunities for interventions which can improve the system energy efficiency and has allowed the real-world impact of low carbon replacement options for this site to be assessed.

Key recommendations

Key data used in study

- 2021 Natural gas consumption — 2,372 MWh
- 2021 heat sales — 1,235 MWh
- Various key geothermal information, provided by GSI — See appendix 7
- Natural gas price (year 1) — 110 €/MWh
- Heat sale price (year 1) — 220 €/MWh
- Network CO_2 emissions — 486 tCO_2/year
- Network length (approximate) — 5.3 km

Findings from site visit (Nov 2022)

A site survey was undertaken in November 2022 – the purpose of this was to gather on-site data to support any future heat decarbonisation options. The site survey was supported by the network operator, SEAI and Geological Survey Ireland (GSI). Network configurations including pumping properties, system temperatures (flow and return to determine circuit level delta-Ts), controls and available metering were all recorded. A review of the potential available land for a shallow geothermal solution was also included. Unfortunately, it was not possible to gain access into any of the properties connected to the heat network, which meant that assessing space for future equipment (such as domestic hot water (DHW) cylinders) was not possible, nor was it possible to take any spot checks on HIU performance.

Methodology

1. Develop an understanding of existing energy consumption, network losses and hydraulic efficiency
2. Determine opportunities to improve network efficiency
3. Determine low-carbon replacement options, looking initially at geothermal energy sources
4. Assess low carbon options using techno-economic model

Existing energy consumption, network performance and hydraulic efficiency

Annual gas data for the heat network was provided by the heat network operator, along with annual heat consumption data for all properties on the network. This gave an initial indication of network performance and how this varies seasonally.

A hydraulic model of the existing heat network was developed based on information provided by the network operator and gathered on-site. This was used to generate estimated seasonal and annual heat losses, based on the system temperatures gathered on-site.

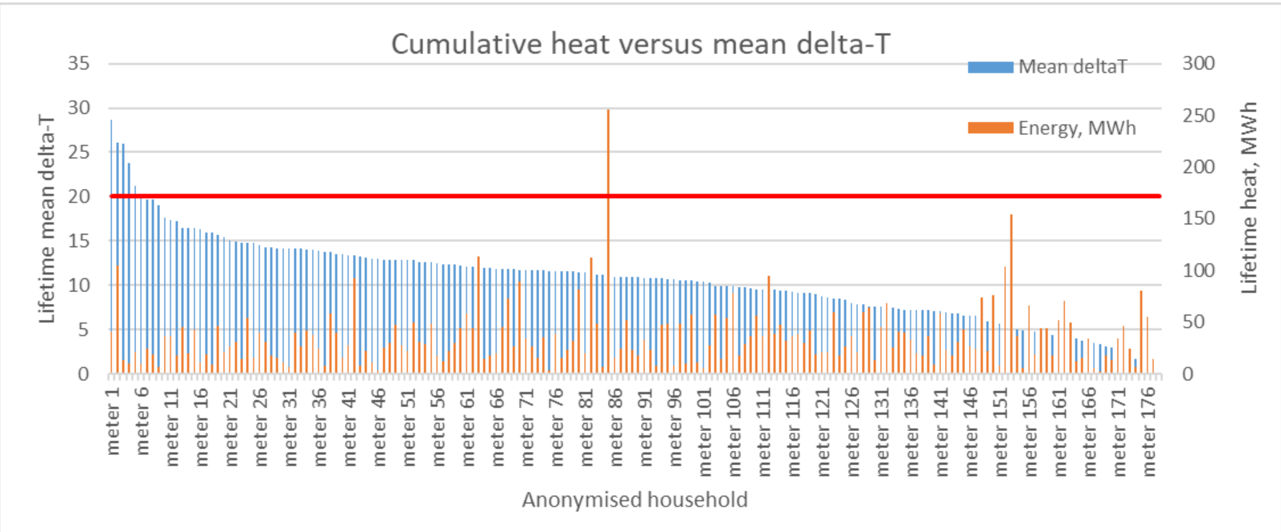
During the site visit, it was established that the network was operating at around 7-10 degC delta-T compared with a design of 20 degC. This is the difference between the flow and return water temperatures, and a higher value leads to more efficient pumping and lower heat losses. This difference evidences a lack of control of the network from the system control valves.

Existing project experience and available data from a project of similar age and performance criteria that supplies a similar heat density of housing was used. This was calibrated against the data provided by the network operator to generate an annual heating profile for Carlinn Hall. This profile was then normalised against a degree-day process to generate our Business As Usual (BAU) network demands, including peak demands which were used for sizing of alternative heat generation plant.

Network performance findings and opportunities

A month (September 2022) of heat meter data, for each property on the network was provided by the network operator. The heat consumed for each HIU was compared against the mean delta-T across the HIU. Only 10 of the 178 HIUs were operating at design or better conditions. 45% of the HIUs were operating at delta-Ts of less than 10 degC (i.e., the return temperature from the HIU is higher than design conditions) - Figure 15. This indicates a lack of control and will lead to higher pumping loads and heat losses. This is only a spot check and cannot be used to show where performance is deteriorating. The network operator does not have responsibility for maintaining the HIUs, which are the responsibility of the homeowners; this is a critical factor in their poor performance.

Figure 15: Cumulative network performance



This identified a major finding and challenge for the site and overall system - not only is it in a relatively low heat density area (due to large, efficient buildings with low heating demands), but it also faces certain operation and management issues. The root cause of the observed high return temperatures cannot be pinpointed on a single or few poorly performing HIUs, the vast majority of these are not performing as designed.

Essentially the network operator is not controlling the volume of water being pumped through the estate as the pump sets are all set on fixed output, nor is there any control over the resulting return temperature. To have a successfully operating, decarbonised heat network in the future the network should be brought under control via a centralised maintenance regime.

Low carbon heat generation options

Three low-carbon scenarios were developed that were modelled using a combination of in-house tools and dynamic simulation (Energy Pro™) programmes.

1. Centralised ground source heat pump
2. Centralised air source heat pump
3. Centralised biomass system

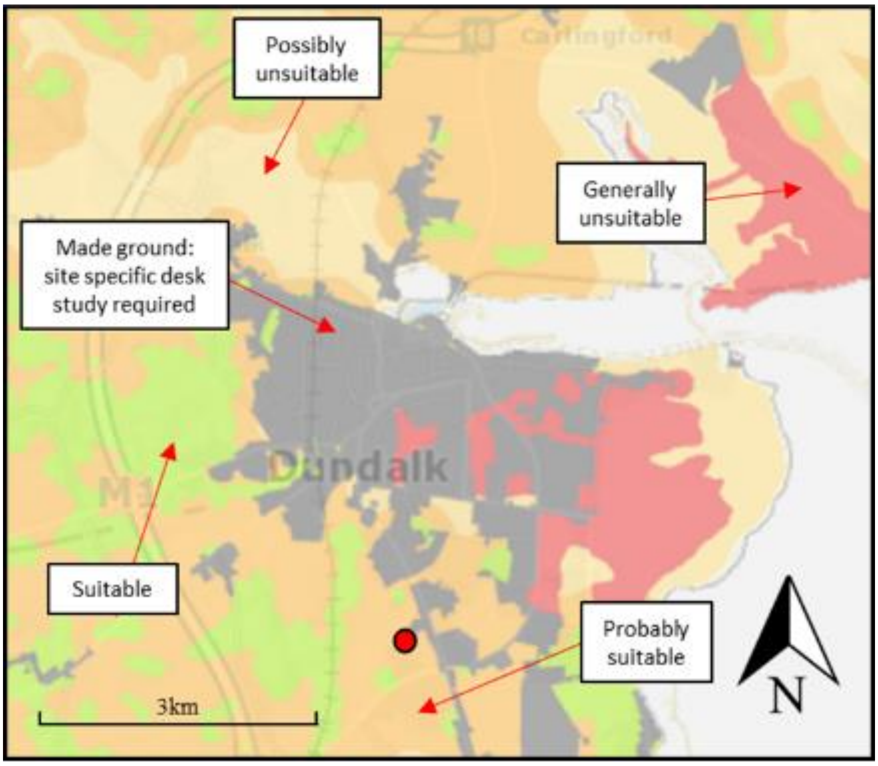
Shallow geothermal findings (Ricardo with data support from Geological Survey Ireland)

Support on the project was provided by GSI who provided a case-study report of the geology of the local area. This provided a greater understanding of the sub-surface geology, hydrogeology (including detail on aquifers) and summaries on both shallow and deep geothermal potential at the site.

Geological Survey Ireland's shallow geothermal suitability maps have indicated that this site is generally unsuitable for open-loop geothermal systems, due to the lack of presence of a productive aquifer. This is due to the hydraulic properties of the bedrock beneath the site. The maps suggest that a vertical closed-loop borehole system could be a possible solution (Figure 18). Ricardo have concluded that heat extraction rates of ~ 30W/m may be possible. A number of techniques can be deployed to estimate the borehole array length – our analysis used two methods: one using the heat demands (kW) and another using the annual heating consumption (kWh).

There is insufficient space for a horizontal closed loop system, and so this is not included in the analysis. Four areas for potential vertical borehole locations at Carlinn Hall were identified, and this was used to determine that it is spatially possible to install the required borehole array to meet the heating demands at the site.

Figure 18 Map showing suitability of closed-loop geothermal systems in the surrounding area. Carlinn Hall shown in red (Source: GSI).



<u>Techno-economic modelling of chosen scenarios</u>

Methodology

Scenarios

Three scenarios for providing low-carbon heat to the network were determined and analysed in the project based on site and shallow geothermal findings; these were:

- Centralised shallow ground source heat pump
- Centralised air source heat pump
- Centralised biomass

Each scenario was modelled using both in-house and dynamic simulation tools to produce energy flows; these combined with the estimates on Capital Expenditure (CAPEX), Replacement Expenditure (REPEX) and Operational Expenditure (OPEX) were then fed into the techno-economic model that was produced for the project. Other costs such as social cost of carbon emissions (i.e., not real cashflow items) can be calculated using the techno-economic model.

CAPEX

For each scenario the estimated CAPEX and REPEX over a 25-year period were determined. The upfront CAPEX for each scenario varies with the technology and is shown in Table 22.

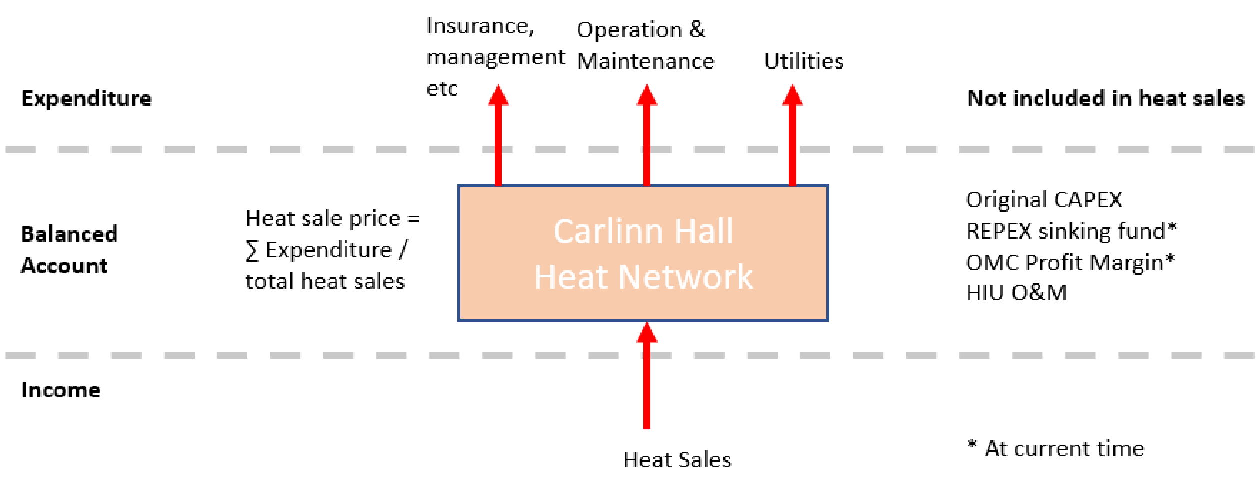
Table 22: CAPEX summary

	BAU	Scenario 1 GSHP	Scenario 2 ASHP	Scenario 3 Biomass
CAPEX (€m)	0.02	3.63	1.44	1.14

Heat Sale pricing

Heat is sold to customers on the system based on a monthly tariff which flexes with the demands on the network. This leads to high costs to residents during periods of low heat sales (via the metered heat) but moderate gas demands (centrally metered). Each scenario determined balanced out the expenditure on the network (i.e., it included utilities (input fuel), operation & maintenance and assumed insurance/management fees against the heat sale price – resulting in differing heat sale prices for each scenario - this is shown in Figure 7. This method showed that both of the heat pump solutions could result in lower heat sale prices than are currently charged to the residents. CAPEX and REPEX are not factored into the heat sale price.

Figure 7: Heat Sale Price calculation boundary



The heat sale prices are calculated for each scenario based on Figure 7 – the differing utility and operation and costs generate the difference in heat sale price (we have assumed that the insurance and management of the heat network does not change between the scenarios modelled). The heat sale prices used in the analysis are shown in Table 17

Table 17: Heat sale prices, without CAPEX or REPEX being factored in

Scenario	Heat sale price, Day 1 € / MWh
BAU	220
Scenario 1, GSHP	164
Scenario 2, ASHP	187
Scenario 3, Biomass	327

TEM - Outputs

The outputs from the TEM include discussion on operating expenditure, net present value calculations and carbon scheme calculations.

OPEX

The GSHP has the lowest Operational Expenditure (OPEX) of the three scenarios due to the superior sCOP resulting in the lowest utility prices – and it has the lowest of the three low-carbon solution O&M costs.

Table 29: Operational expenditure, 25 period

	BAU	Scenario 1 - GSHP	Scenario 2 - ASHP	Scenario 3 - Biomass
	(€m)	(€m)	(€m)	(€m)
Operational Expenditure (25 year)	(10.34)	(8.29)	(9.44)	(16.55)
Compared to BAU	-	2.05	0.9	(6.22)

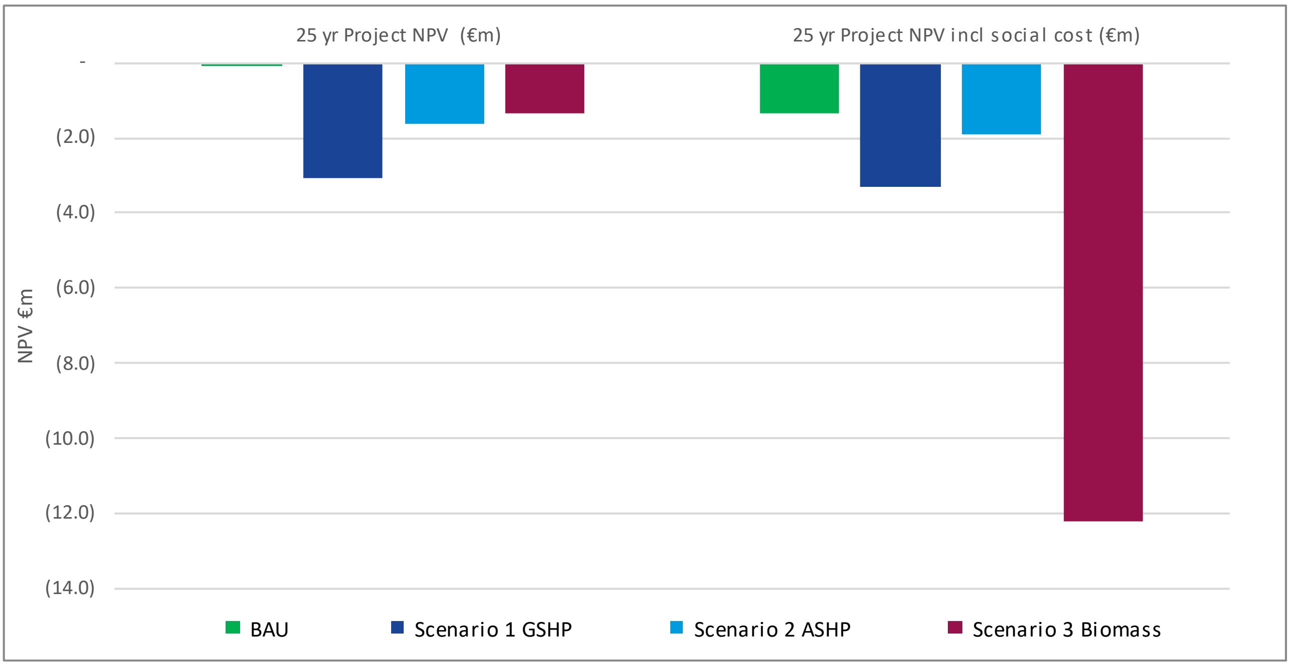
The GSHP is calculated to be approximately €1.15m cheaper over 25-years compared to the ASHP solution.

NPV (Net present value)

The financial considerations and heat sale price are incorporated in a techno-economic model, which was supplied to SEAI as a deliverable on the project. This provides index-linked time-series outputs of various commercial considerations of the network. **None of the scenarios evaluated had positive 25-year NPVs from the perspective of the network operator (Figure 27).**

If ignoring the social costs of carbon, the biomass scenario is fractionally the most attractive – however it has a high heat sale price. Therefore, this technology is unlikely to meet the primary focus of low heat sale costs for residents. When including social cashflow items that include air quality, the biomass scenario is the poorest performing by a significant factor.

Figure 27: 25-year NPV. This figure shows the NPV when including and excluding the social costs of carbon.

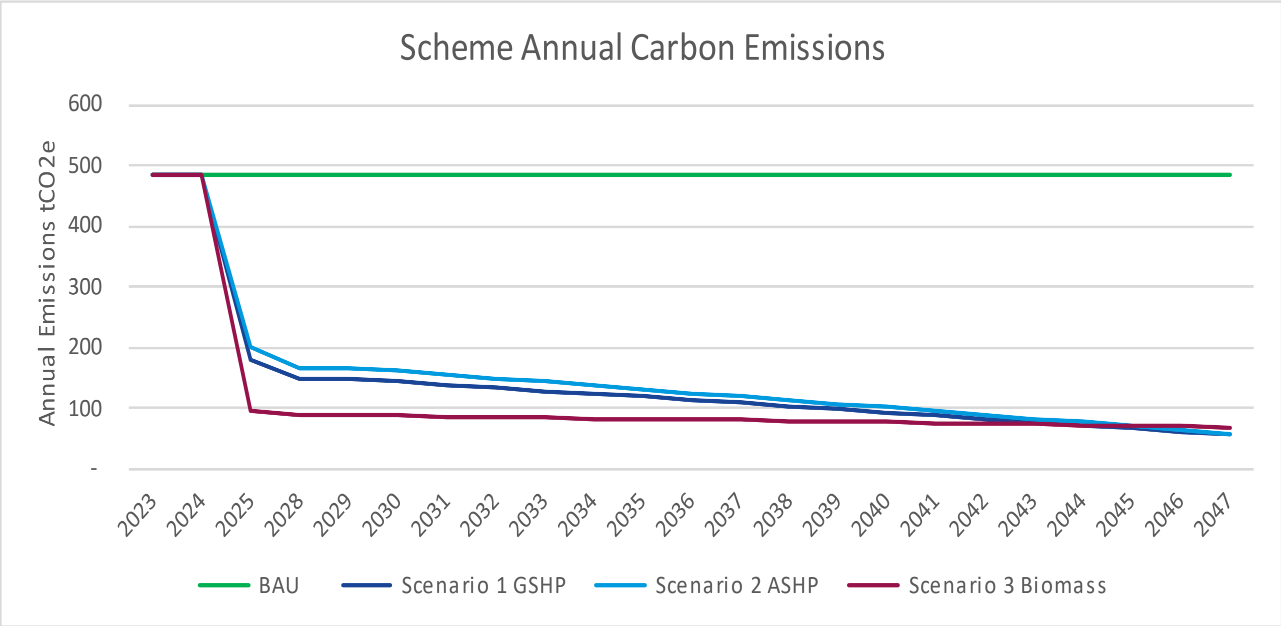


Whilst the GSHP has the superior OPEX over the course of the model the difference in OPEX between the GSHP and ASHP is not great enough to overcome the difference in CAPEX required, thus the NPV analysis shows that the ASHP scenario performs better than the GSHP scenario in terms of NPV.

Scheme carbon emissions

All scenarios had substantially lower carbon emissions than the existing BAU. The heat pump scenarios tend towards zero emissions as the grid decarbonises (Figure 33). There are residual fossil fuel emissions for peaking plant included in each scenario.

Figure 33: Annual carbon emissions



Key recommendations

Network and ownership model

The existing ownership model means that the network operator does not have responsibility for the HIU maintenance on the system. The poor HIU performance is one of the key findings from this report and working towards resolving this (by lowering the return temperatures and thus increasing the delta-T of the network) is a key prerequisite to a successfully operating heat network in the future.

We recommend that the overall operation and maintenance of the HIUs is undertaken by the heat network operator, and a strategy to take control of this maintenance requirement is necessary.

This is necessary to:

1. Increase the delta-T on the network – this will mean the network is operating as designed, with the maximum energy extracted at each HIU/terminal resulting in lower network energy demands including lower pumping rates
2. Prepare the network for a low carbon alternative heating source. In order for a new low-carbon heating source to be implemented on the network – it is imperative that the network is operating efficiently, reducing risk of excessive losses or use of back-up heat generation

Heat network customers do not enjoy the consumer protection other regulated utilities do. Once the network is in operation, there is limited oversight and ability to enforce adequate operation.

1. Approach to consumer protection standards for Ireland to be considered, building on the experience of other countries with varying models of heat network ownership. This could be managed by an independent or not for profit company.
2. Heat network licensing could be considered, ensuring minimum standards via the mechanism of ongoing state regulation.

Technology

The recommended technology solution is a centralised air source heat pump based on the TEM analysis.

An ASHP system could be implemented the quickest (the time requirements for drilling a multi-borehole array would not be insignificant and could take 6-12 months to complete depending on site conditions and programme of works) and it would be the cheaper of the heat pump solutions to install. It also does not need verification of conditions (as the heat source (air) is known) to prove it would operate as outlined in this feasibility study – geothermal energy, whilst viable at this site, does need further verification of ground conditions.

This solution can result in low heat sale prices (though notably not as low as the GSHP solution), low carbon emissions and is a solution that could be implemented without significant disruption during the installation phase at the site. Note however that a suitable location for any external plant (with appropriate sound attenuation devices) is needed, we have suggested some potential areas in Figure 17 and these need to factor in adjacency to nearby houses. If located on the north-side of the existing energy centre, this is approximately 60 feet from the nearest dwelling -if on the south-side of the energy centre – the nearest dwelling is ~100 feet away. In both cases, sound attenuation would be required, but the magnitude and efficacy of these devices may vary (the location of external plant and the risk of noise is a key design consideration).

A ground-based system could result in lower heat sale prices to customers and lower OPEX to the O&M provider over the course of a 25-year The GSHP solution also has marginally the lowest lifetime carbon emissions (again lending to the superior sCOP).

There are greater risks associated with the GSHP solution – predominantly down to the currently unknown ground conditions, size and location of the potential array and unknown land ownership. An on-site test borehole and thermal response test (TRT) should be implemented (for any moderately sized GSHP project) should a GSHP solution be progressed. It is understood that a test-borehole is proposed at DKIT; when completed, heat extraction rates could also be verified and a decision over any potential future decarbonised heat solution could be made (if no test-borehole planned at Carlinn Hall).

A shared-loop ground source heat pump heat network (i.e., a system which uses a shared ground loop, but each dwelling has its own small heat pump unit installed to upgrade the heat) is not suitable at this site due to incompatibility with the existing infrastructure, flow rates required and delta-Ts that this type of low temperature heat network would operate at.

1. INTRODUCTION

1.1 SCOPE

This study includes the analysis of the operational performance of Carlinn Hall's heat network and heat generation which subsequently informs the primary focus of the study; the potential for the utilisation of shallow geothermal heat and other low carbon heat sources to decarbonise the existing system.

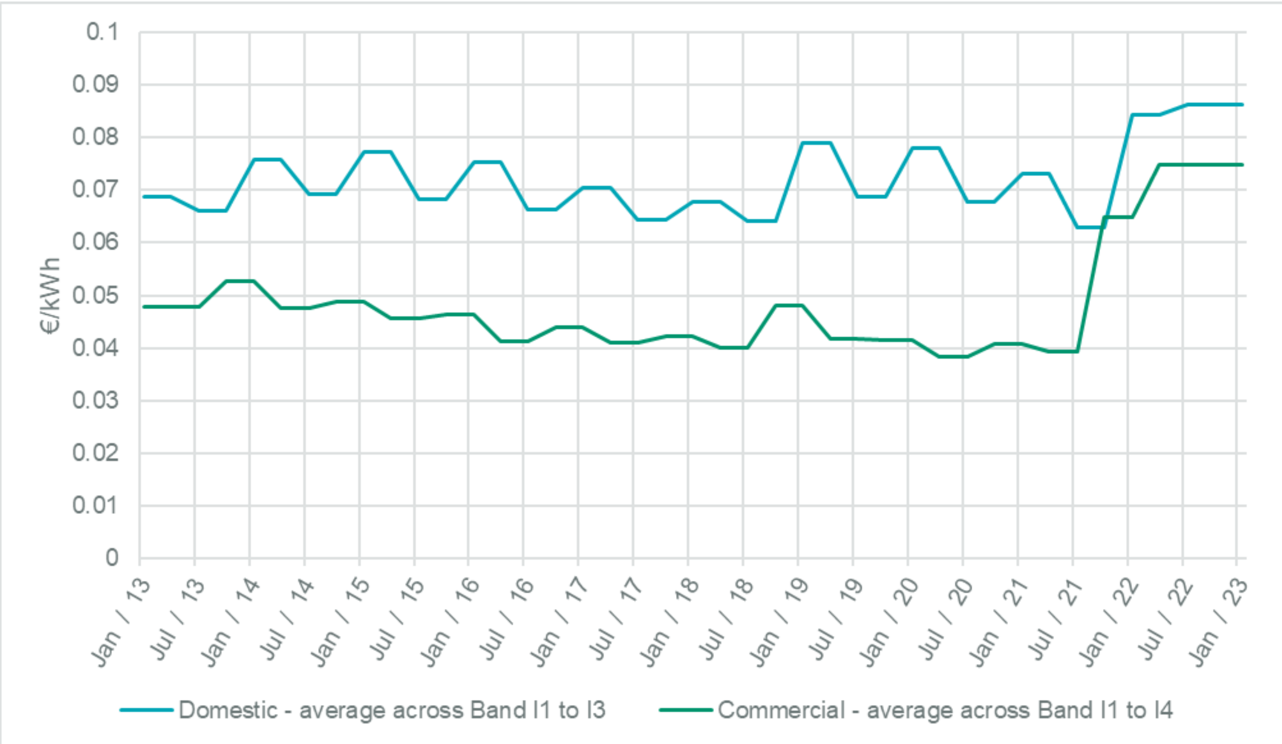
The analysis of the operational data been used to 1) develop an understanding of existing energy consumption, network losses and hydraulic efficiency. This analysis provides 2) an insight into the opportunities for interventions which can improve the system energy efficiency and has 3) allowed the real-world impact of low carbon replacement options for this site to be assessed.

1.2 KEY AIMS AND OBJECTIVES

1.2.1 Impacting energy bills

The primary driver for this work is the significant rise in gas prices that occurred in 2021 and 2022.

Figure 1: Historic average domestic and commercial natural gas rates in Ireland; 2013 – 2023. Source SEAI[3]



Unlike typical domestic customers who are protected from unpredictable utility price variations, customers on communal heating networks utilising gas boilers/CHP, such as at Carlinn Hall, are exposed to the volatile nature of non-domestic (commercial) natural gas rates **which are generally passed on to them via their heat tariff**. The network is operated by an Owners Management Company (OMC) service provider that is covered by the MUD Act 2011[4] which means contracts with providers of goods and services are limited to a maximum of 3 years. This has impacted contracts with utility providers and the network O&M provider, resulting in uncertainty that could lead to reduced maintenance regimes.

At present, there is a significantly increased risk of households being in fuel poverty if their homes are heated by heat networks utilising gas boilers due to the higher commercial rates and losses on the network which may

[3] https://www.seai.ie/data-and-insights/seai-statistics/key-statistics/energy-data/#comp00005c0fcbea00000088e671a3
[4] https://www.citizensinformation.ie/en/housing/owning_a_home/home_owners/management_companies_for_apartment_blocks.html

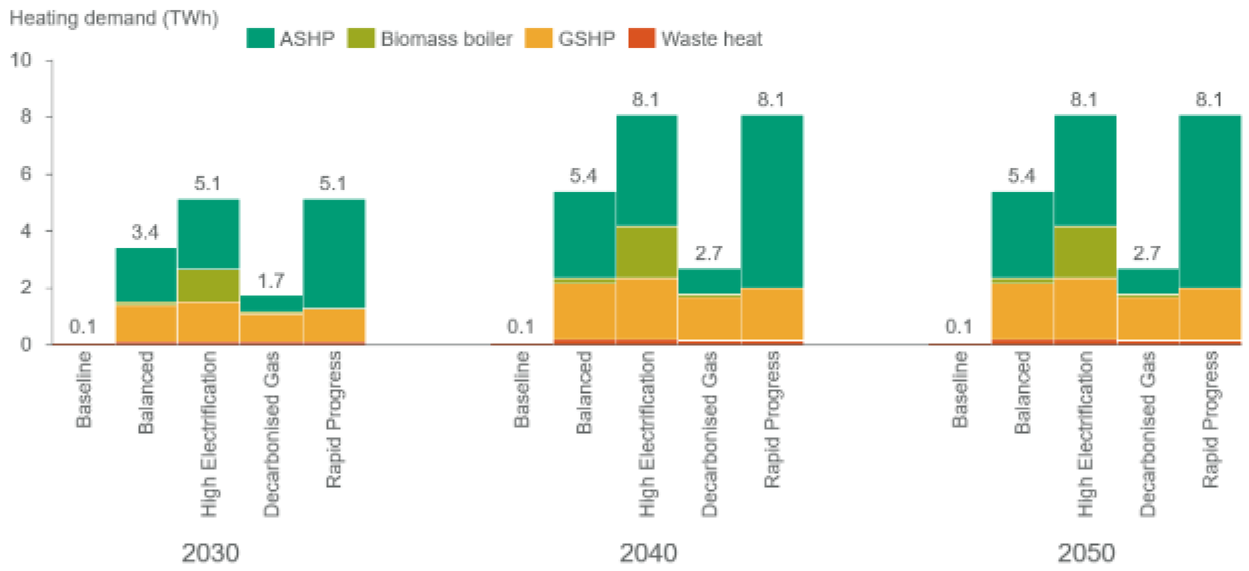
be passed on to residents. However, it is worth noting that although currently less than 1% of residences in Ireland are in a communal heating network, the Climate Action Plan 2023 commits to 10% district heating by 2030 and as such there are opportunities for lessons to be learned from the existing legacy networks.

There is a need for communal heating networks to investigate technology models that better protects consumers from such high prices and align with low carbon heating objectives in the Climate Action Plan. The rise in natural gas prices has decreased payback times for investments in alternative heat sources. The National Heat Study[5] identified the potential for ground-source heat, particularly with regard to its potential to be utilised for communal heating networks. It has been identified by SEAI that shallow geothermal heat has the potential to reduce both operating cost and carbon emissions associated with the operation of similar heat networks.

1.2.2 Aligning with Ireland's decarbonisation trajectory

There are an estimated 13,000 residents on communal heating systems in Ireland and so transitioning existing communal heating systems onto low-carbon heat sources will be part of the heat decarbonisation journey necessary for Ireland to meets its Net Zero 2050 target, Figure 2 .

Figure 2: Total annual heating demand supplied by each district heating technology by scenario, in 2030, 2040 and 2050, including heating demand in all sectors suitable for district heating (residential, commercial, public) – figure reproduced from the National Heat Study.[6]



Heat demand in Ireland constitutes approximately 40% of total Irish energy usage, with residential heating accounting for approximately 25% of energy-related CO_2 emissions[7]. The National Heat Study found that district heating has the ability to play a significant role in Ireland's decarbonisation trajectory, with the potential to supply up to 50% of building heat demand.

As well as waste heat and low carbon CHP, the study identified that heat pumps and geothermal heat sources can be utilised as a heat source for communal heating networks. The Climate Action Plan 2023 is targeting retrofitting of homes, the use of heat pumps, and up to an 80% renewable electricity share by 2030[8]. Therefore, the carbon intensity of the heat delivered by a heat pump system, used to extract and upgrade shallow geothermal heat is set to decrease along with the increased share of renewable electricity generation which will decarbonise the grid.

Although this report is focused on the Carlinn Hall network specifically, the utilisation of shallow geothermal heat, or other low carbon sources into existing heat networks is a key study aim. We can see from Figure 2

[5] https://www.seai.ie/data-and-insights/national-heat-study/

[6] Net-zero by 2050, SEAI, 2023 - https://www.seai.ie/publications/Net-Zero-by-2050.pdf

[7] https://www.esri.ie/publications/decarbonising-heat-through-electricity-costs-benefits-and-trade-offs-for-the-irish

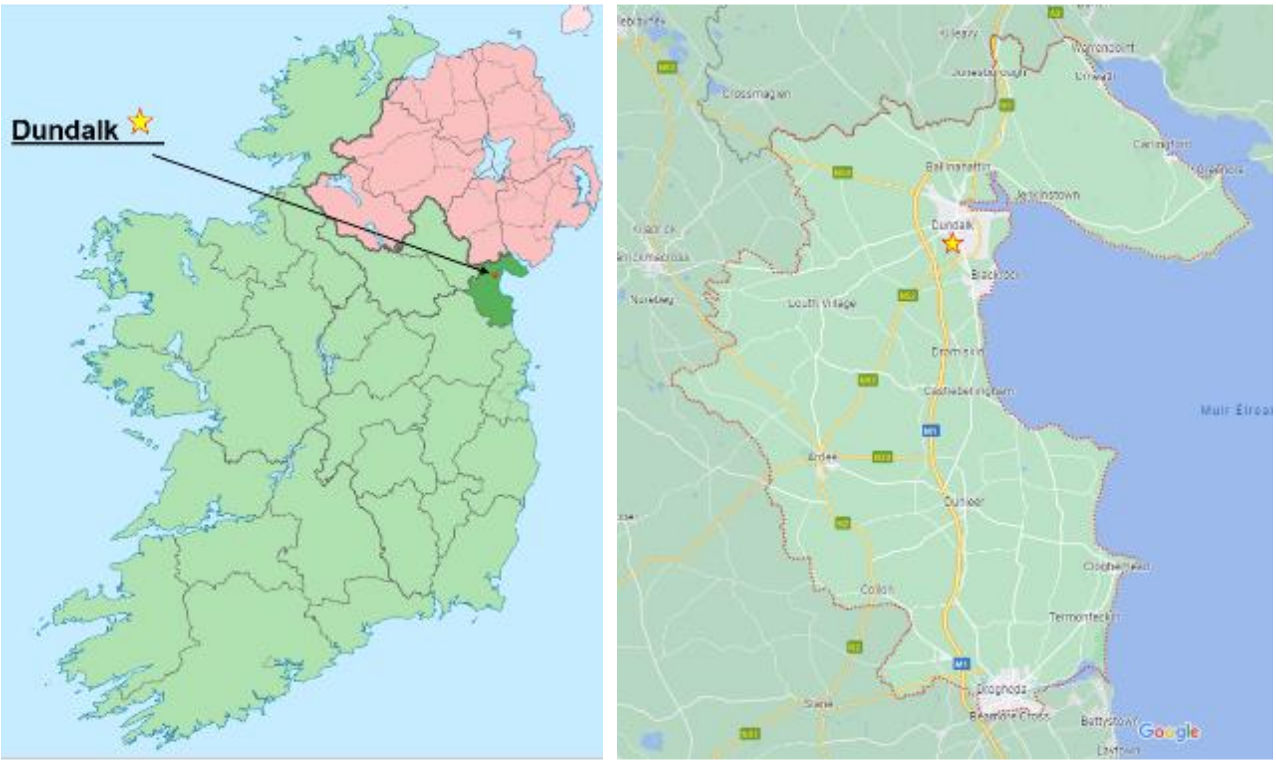
[8] https://www.gov.ie/en/publication/7bd8c-climate-action-plan-2023/

that both air source heat pumps (ASHPs) and ground source heat pumps (GSHPs) are proposed as key technologies for heat generation in heat networks across all scenarios outlined in the National Heat Study. GSHPs can offer unique benefits to decarbonisation efforts as they are not impacted by outdoor air temperatures. This can allow GSHPs to minimize peak demand requirements on power grids, which will become increasingly constrained as the electrification of heat and transport continues. In practice, numerous solutions will be required, in the near-term, to decarbonize the Irish heat sector, including ASHPs, GSHPs, and other heat sources.

1.3 STUDY AREA

The Carlinn Hall communal heat network is located at the southern end of Dundalk, County Louth; Figure 3, Figure 4 and Figure 5.

Figure 3: Left: County Louth shown in dark green. Right: Carlinn Hall in Dundalk shown with star. © Google maps



The system supplies heat to approximately 178 domestic properties within a housing estate, which was constructed over several phases between 2007-2018. The system supplies heat to customers via four separate underground heating circuits that originate from a central energy centre on the eastern side of the estate.

Figure 4: Carlinn Hall, location © Google Earth

Figure 5: Carlinn Hall, neighbourhood © Maxar Technologies

1.4 EXISTING HEAT NETWORK

The heat network at Carlinn Hall serves 178 properties[9] and was designed and installed in phases between 2007-2018, Figure 6.

Figure 6:Carlinn Hall estate map with communal heating pipework shown. Image taken from data gathered during site visit in December 2022.

It is currently served by two gas-fired Die Dietrich 1.22 MW output boilers and two 20 kWe output micro-CHP units[10]. There is some small buffer vessel storage of approximately 957 litres each for the CHP units. It is believed, but this was unconfirmed, that the system was originally designed for a biomass boiler configuration. The network is split into 4 distinct circuits and has a total length of approximately 5.3 km around the housing estate. In 2021, the heat network consumed 2,372 MWh of natural gas to heat the properties.

1.4.1 Network Operator

The network Operation and Maintenance (O&M) provider is Frontline Energy, operating on behalf of the OMC, understood to be a shell company that owns the centralised energy centre and heat network. The OMC was created when the Carlinn Hall development was constructed. Each property connected to the heat network has its own Heat Interface Unit (HIU) and ultrasonic heat meter for payment purposes. The network O&M provider has responsibility for maintaining and operating the energy centre and network up to the billing meter in the properties but does not have responsibility for maintaining the individual HIUs in each property, this is

[9] This is based on the metering data provided by the OMC

[10] One of the CHPs is currently out of operation

the responsibility of the property owner. The network O&M provider are responsible for taking monthly (previously bi-monthly) meter readings across the system for billing purposes.

1.5 EXISTING HEAT SALE PRICE

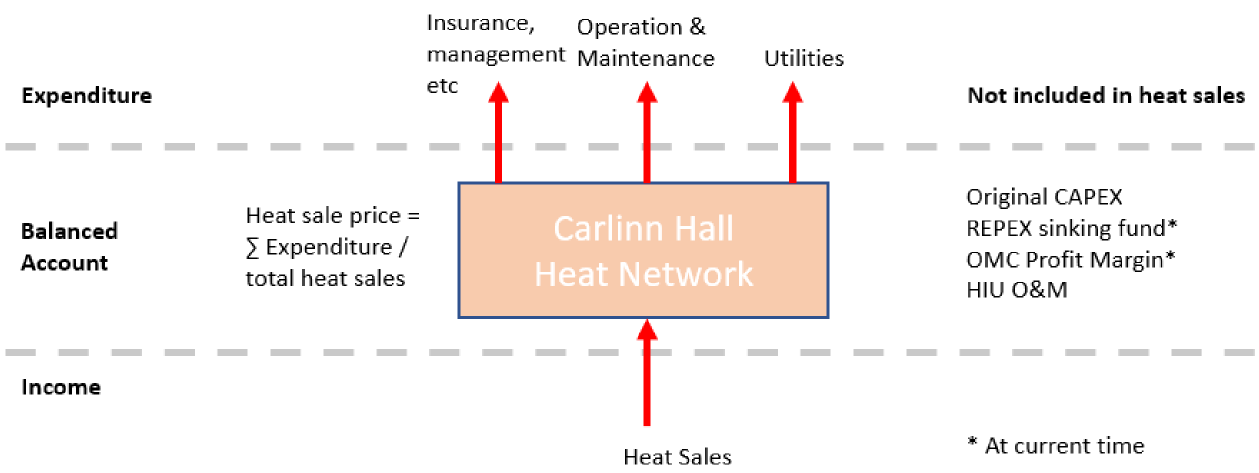
Discussions with the network O&M provider have identified that the heat sale price is calculated by:

1. Summation of all utility costs in period
2. Summation of all O&M costs in period, presumably[11] including insurance, management costs, any building / land rental, and rates.
3. Division by total heat sales from customer heat meters to generate a price per kWh

Our understanding is that the heat sale price does not include provision for repayment of any loans associated with original capital outlay or any plant replacement sinking fund. We have been told that given the high energy prices, no OMC operating margin is included within the current rates[12].

This heat sale price boundary is shown in Figure 7.

Figure 7: Heat Sale Price calculation boundary



At the time of writing, in late 2022 the current utility prices and subsequent heat sale prices were:

- Natural gas unit price 110 €/kWh
- Heat sale unit price 220 €/kWh

Note that the heat sale price fluctuates with seasonal demand – meaning that the residents have a variable heat sale tariff.

[11] Has not been explicitly confirmed by provider
[12] Again, we have not seen a breakdown of these numbers to verify this split

2. UTILITY DATA ANALYSIS

2.1 OPERATIONAL DATA

The heat network O&M provider was able to provide the following data for the site. This is limited by available data collection infrastructure:

- Monthly gas demand for energy centre
- Heat meter readings for every two-month period from each customer
    - Note they have since moved to a monthly domestic billing regime
- Some recent heat sale prices for residents

Table 1 outlines the existing heat network gas consumption and heat sale volume for all properties. Information from Building Energy Reports (BER) is shown for comparison.

Table 1: The heat network demand data of the Carlinn Hall heat network over one year; 2021. This includes the annual A) the heat network gas consumption (MWh) i.e., gas consumed by boilers to supply heat to heat network. B) Heat sales data (MWh); the total heat consumed by properties C) The average BER data of heat and power demand per property floor area per year– based on 11 BERs supplied, note this does not split out heat and power energy demands.

	Parameter	Heat - MWh	Cost (€) (note 1)	MWh/property
A	Heat network gas consumption (2021) – real data (note 2)	2,372	260,920	12 – heat only
B	Heat sales (2021) – real data	1,235	271,700	6.2 – heat only
C	Average BER (simulated demands)	Not provided	N/A	7.9 - heat and power (note 3)

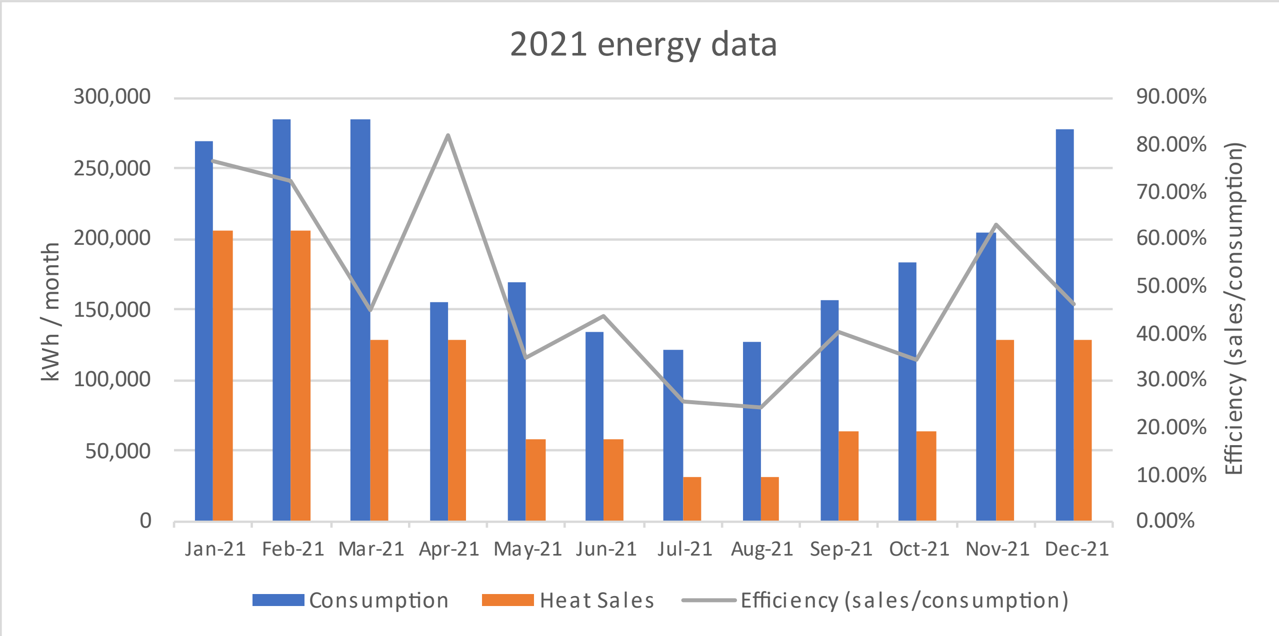
Note 1: Unit prices for natural gas and heat sales fluctuate through the year, year 1 prices are shown.

Note 2: This includes all losses from combustion efficiency and heat losses from the network (i.e., it is the actual volume of gas paid for by the network O&M provider

Note 3: The BER data is provided as a kWh/m^2/year for all energy demands – it is not split out between heating (space heating and domestic hot water heating) and power requirements.

The sales/ consumption efficiency is the ratio between the amount of heat, which is paid for by the residents of Carlinn Hall, through their Heat Interface Units (HIUs) and the gas consumption of the system's boilers and CHPs. Analysis of the operational data has revealed that this efficiency varies significantly throughout the year, see Figure 8. Based on this, the overall annual efficiency of the system was **52.1%.** If we were to assume that network losses were to represent 15% of heat demand, and the gas boilers operate at an overall efficiency of 85% then the overall system would be operating at an efficiency of ~74%. **A well operating heat network would be expected to see the difference between the consumption and heat sale figures to be much closer to one another without significant difference between summer and winter operation**. Note that the sales and consumption data for April were very similar which has led to a high "efficiency" of the system, it is unclear whether this was down to work undertaken by the network O & M provider or whether this is potentially erroneous.

Figure 8: Carlinn Hall Heat Network Monthly gas consumption, adjusted heat sales[13] and sales/ consumption efficiency in 2021



The sales / consumption efficiency is an effective metric for measuring the financial performance of the system. However, there are limitations with this method. This figure encompasses 1) the combustion efficiency of the boilers, 2) the gas input into the combined heat and power (CHP) units, 3) the losses throughout the distribution pipework and 4) any further (small) losses that may occur within each resident's dwelling upstream of their heat meter. It is important to note that this sales/ consumption efficiency does not provide an insight into the specific points across the system where these losses are occurring, but rather as a whole system.

Heat sales decrease significantly in the summer months where there is little demand for space heating, but Domestic Hot Water (DHW) demands remain. The calculated losses on the heat network are calculated to stay roughly the same during the summer (slightly lower due to higher mean ground temperatures, this has been calculated using our hydraulic mode of the existing network) meaning that in the summer months, the gas demand is still relatively high, leading to a proportionally lower system efficiency (i.e., heat sales are lower, losses remain relatively constant). The overall system is performing below what would be considered good practice, and this is outlined in Section 3.

2.2 CHP / POWER

At the time of writing, electricity consumption data (for the energy centre) has not been made available, this includes current electricity utility unit rates.

There are two 20 kWe micro-CHP units in the Energy Centre for Carlinn Hall, however one is not operational; the required repair cost exceeds the perceived value it delivers, and based on site discussions, is unlikely to be repaired. Operational data from the operational unit was accessed during the site survey via its user interface, see Figure 9.

Further analysis is provided in Appendix 2. Based on this, we surmise that the operational unit runs constantly at or near peak output, tracking the energy centre electrical load. There appears to be no export of electricity. The heat demand of the system always exceeds the operational output of the engine, so all heat is rejected onto the return leg of the heat network, prior to the active boiler(s), thus we assume that the CHPs were designed to supply electricity for the energy centre.

[13] Historic heat sales are only available for 2-month periods; they have been weighted to reflect the gas usage in each of those months, to better reflect the anticipated usage. This leads to a slight inaccuracy in the month-by-month figures, but annual totals are not impacted.

Figure 9: CHP electrical generation output screen

2.3 HEAT LOADS AND PROFILES

The key utility data available for the analysis is the monthly gas consumption and the bi-monthly heat sales records. As discussed in Section 2.1, this information can be used to infer the consumption / sales efficiency but cannot reveal much detail into the current operational performance of the system. A number of modelling and analytical techniques have therefore been utilised to undertake a more forensic approach and identify where losses are occurring and the magnitude of these losses.

The Carlinn Hall heat network is similar in terms of demand density, networking, and overall performance to others that Ricardo team have direct involvement and operational insight into[14]. Using normalised profile data from other similar sized and scoped projects has allowed us to generate a reasonable estimate of how the communal heat network is expected to be operating.

The method used then was:

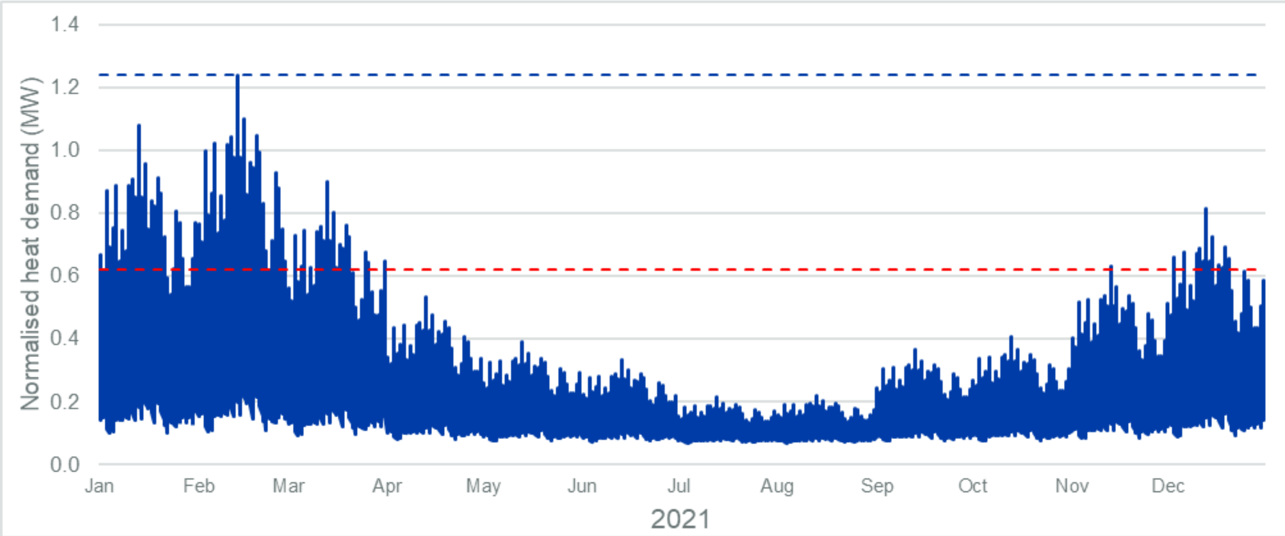
- Normalise 2021 Carlinn Hall heat demand data to local climate[15] (real data)
- Profiled this shape using the similar Scottish site (real data but different site)
- Calculated the heat losses for the network using actual operational temperatures, using our hydraulic model of the existing pipe network (calculated)
- Profiled and added this loss to the heat demand (calculated)

This method provided the estimated annual hourly heat demand (i.e., the required heat to be generated under current operating conditions) profile for Carlin Hall, Figure 10. If hourly or half hourly gas data was available from the energy centre, this would have been used, and would eliminate the need to estimate or use data from other projects to supplement our own analysis.

If hourly or half-hourly data was available this allows for correct calculation of peak demands and subsequent sizing of replacement low-carbon equipment.

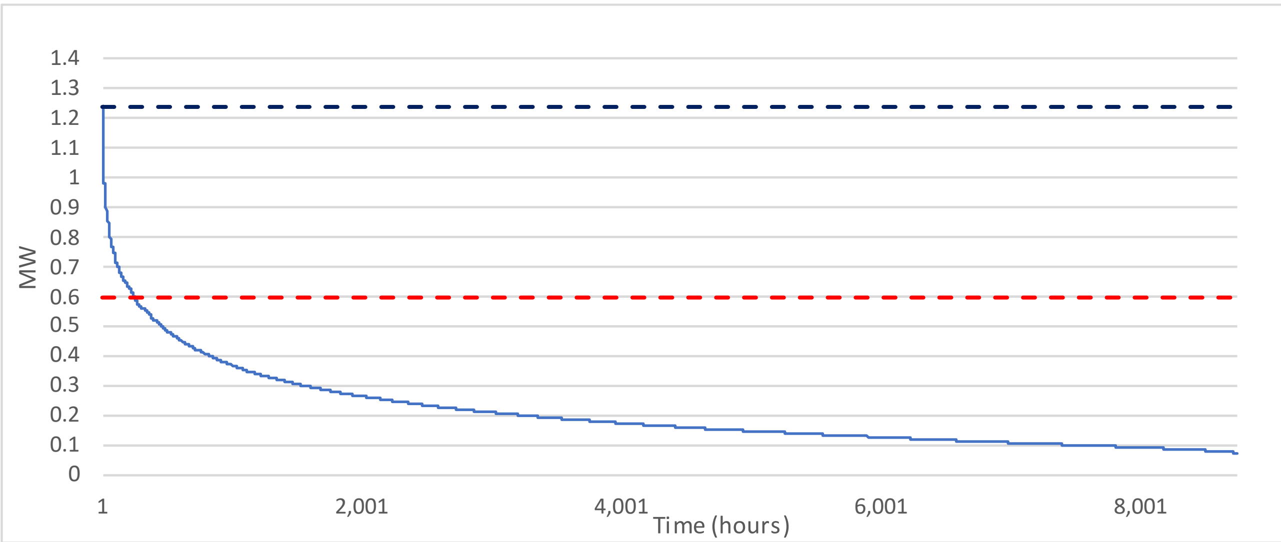
[14] The data chosen was for a residential heat network in Scotland from a similar era, with similar pipe network and housing density
[15] Using CIBSE TM41 methodology, climate data for Dundalk for 2021 compared to a 20 year. average

Figure 10: Annual normalised heat demand profile, based on imported profile shape from similar project. The dotted lines represent the peak demand (blue, 1.2MW) and 50% of the peak demand (red, 0.6MW)



These demands have been ordered in terms of magnitude, highest first in a load duration curve in Figure 11. This technique allows for initial sizing estimation of systems to be undertaken compared to the likely peak demands.

Figure 11: Load duration curve based on normalised heat demand curve (Figure 10). This is a replication of the annual normalised heat demand, ordered from largest demand to smallest demand. The dotted lines represent the peak demand (blue, 1.2MW) and 50% of the peak demand (red, 0.6MW)



From Figure 11 we can see that the peak demand is ~1.2MW. This demand only occurs for a few hours per year, with only ~ 220 hours likely to be above 50% of that peak demand. This is critical for sizing of replacement plant purposes, as it shows that sizing to the peak demand will be oversized for >99% of the year. When developing alternative heating solutions, sizing with a combination of cheaper peak lopping / back-up plant and suitably sized thermal storage to compliment the lower capacity main heat generation technology will be the most cost-effective.

See section 6.3 on page 53 for how this has been undertaken for this site.

This sizing strategy tends to improve both CAPEX (lower kW rating of heating plant (noting that this only represents a small proportion of the total CAPEX)) and OPEX (alternative solution will operate within its designed conditions more frequently using lower kW capacity units compared to peak sizing). If the main heat generation was sized to provide the peak demand the CAPEX would be significantly higher and the units would run at low capacity all year round – which could lead to further operational issues, increasing OPEX. Note that the capacity of existing plant in the energy centre is 2 x 1.22MW gas-fired boilers – so roughly 2 x peak demand.

No data was provided to support the initial design intent, but our assumptions suggest that the original plant was sized at N+1 for this peak load, or perhaps two at 75% of heat demand. This tends to validate the broad accuracy of our profiling method. One would note that the lead boiler will spend much of its life (>50% of the year) operating at loads at or below 200kW, i.e., less than 20% of duty. This is not a particularly efficient mode of operation, hence why often networks would tend to have two+ duty boilers and one standby[16].

2.4 BASELINE CARBON EMISSIONS

Table 2: Baseline Carbon emissions for Carlinn Hall heat network (2021)

	Value	Unit
Natural gas consumed	2,371,884	kWh
Heat sales	1,235,772	kWh
Natural gas grid carbon emission factor (2022)	0.2047	$kgCO_{2e}/kWh$
Network Carbon emissions	486	tCO_2
Estimated electricity generated by CHP (displaced grid electricity)	131,400	kWh
Electricity grid carbon emission factor (2022)	0.2961	$kgCO_{2e}/kWh$
Grid electricity displaced	39	tCO_2

The carbon emissions for the Carlinn Hall system in 2021 were 486 tCO_2e based on 2,371,884 kWh of gas consumed and a gas grid carbon factor of 0.2047[17] $kgCO_2e/kWh$. With no intervention, the annual carbon emissions will tend to remain static.

As there are gas CHPs also installed on-site, electricity is generated that we have assumed satisfies the electrical loads of the energy centre, delivering an estimated 131,400 kWh of electricity, which would otherwise have been consumed by the energy centre from the national grid.

This results in a delivered carbon factor of 0.39$kgCO_2e/kWh$ (network carbon emissions (486 tCO_2) divided heat supplied (1,235 MWh)), i.e., significantly higher than if the dwellings were served by:

- Gas combi boiler 0.2047 / 85% (efficiency) 0.2408 $kgCO_2/kWh$
- Individual ASHP 0.2961/ 2.9 (COP) 0.0846 $kgCO_2/kWh$
- Direct electric 0.2961/ 100% (efficiency) 0.2961 $kgCO_2/kWh$

2.5 HEAT DENSITY REVIEW

LHD is a measure of heat load per meter of heating pipework and can be treated as a measure of how hard the infrastructure is working. High values show that the investment supports plenty of heat flow; low values

[16] The boilers can in theory reach in excess of 90% gross calorific efficiency at full constant load, based on manufacturer's data sheet. Part load efficiency reduces by 10% (not to be confused with part load efficiency of the Boiler Efficiency Directive which shows a higher efficiency but based on a return temperature of 30 degC), but below 20% operation can be unstable, leading to short cycling. Manufacturers' data does not tend to support what actual efficiencies will be in this region, it is likely to be around another 10%, i.e., < 70%.

[17] Public Spending Code – Supplementary Guidance (https://assets.gov.ie/45078/b7dbf515ad694c3e8b2c37f1094b7dca.pdf)

show sub-optimum network nodes. At outline stage this can give an approximation for identifying areas where a heat network may be viable. Otherwise, it can be used for benchmarking when exploring % network losses.

The buried pipe network is approximately 4.6km in length (trench length, made up of 4.6km of flow, 4.6km of return pipework, often in a shared duo-pipe outer casing). Approximate takeoffs per pipe length are shown in Appendix 6.

This equates to a linear heat density (LHD) of 515 kWh/m.year i.e., for each meter of pipe, the network supplies this amount of heat per year (i.e., 2,371,884 / 4,600).

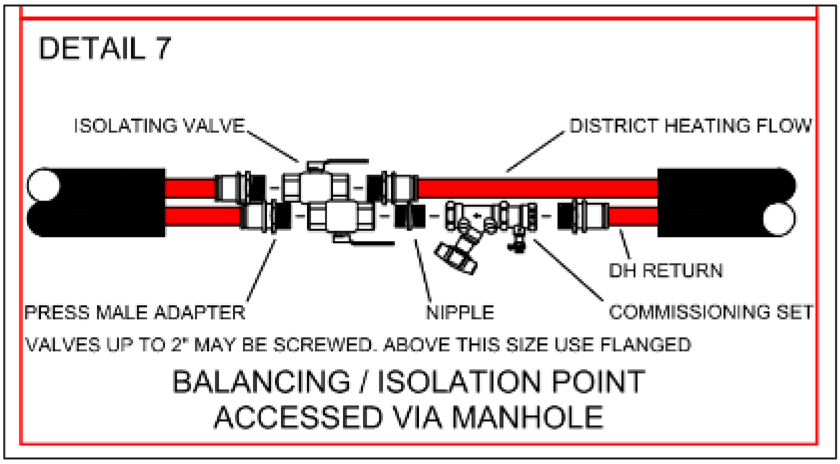
Overall, this is a low figure compared with the traditional[18] typical expected figures for economic networks (circa 3,000-6,000 kWh/m.year[19], although comparable with similar networks of size and serving new build detached / semi-detached housing. In the National Heat Study, LHDs between 1,000 -10,000 kWh/m.year are highlighted as being viable for investigating for district/communal heating[5].

Essentially, this low heat density is caused by the housing density and relative levels of insulation, and there was limited scope in the original network design to have improved this[20].

One further concern over network heat losses would be the manholes on the site. Damaged, water-saturated insulation increases local heat losses, and risks longer term leakage. The design drawings (Figure 12) show non-standard non-PEX (Cross-Linked Polyethylene) system fittings[21] are used. This is a risk in a network for leakage and heat loss; non-standard fittings do not maintain the water barrier over time, leading to water ingress and damage.

The manholes were not available for inspection on the day of our site survey; we recommend these are investigated as part of the O&M works. Our heat losses calculation, based on the available evidence, does not assume that there is significant leakage or abnormal heat loss from the network[22].

Figure 12: Manhole detail with non PEX fittings; protection level unknown, detail from drawing files provided in the study



[18] The drive to decarbonise means that these traditional benchmarks will not alone be the arbiter of network initial viability, but they still serve a purpose

[19] The LHD value for economic viability will vary depending on the specific guidance for the location of the heat network. In Scotland, a LHD value of 4,000kWh/m.year is used in the first screening for heat demand density, whereas the in UK Second National Comprehensive Assessment (NCA) a LHD requirement of 6,607 kWh/m.year is used.
(https://www.theade.co.uk/assets/docs/nws/ADE_Briefing_-_First_National_Assessment.pdf)

[20] Certain unnecessary pipe lengths have been included within the design drawings, presumably based on a faulty understanding of how a variable volume heat network should be balanced. Their influence would not be huge though.

[21] PEX systems do not tend to have pre-insulated ball valves for insertion in manholes (as opposed to direct burial), and certainly do not have pre-insulated commissioning sets

[22] We have past experience of this type of failure. The impact on heat loss is not so significant compared to the damage water loss or water ingress can do to system integrity and lifespan. Thus, our assumption on heat loss does not make a material difference to this analysis. It does however remain a long-term risk for the network, that is worth investigation.

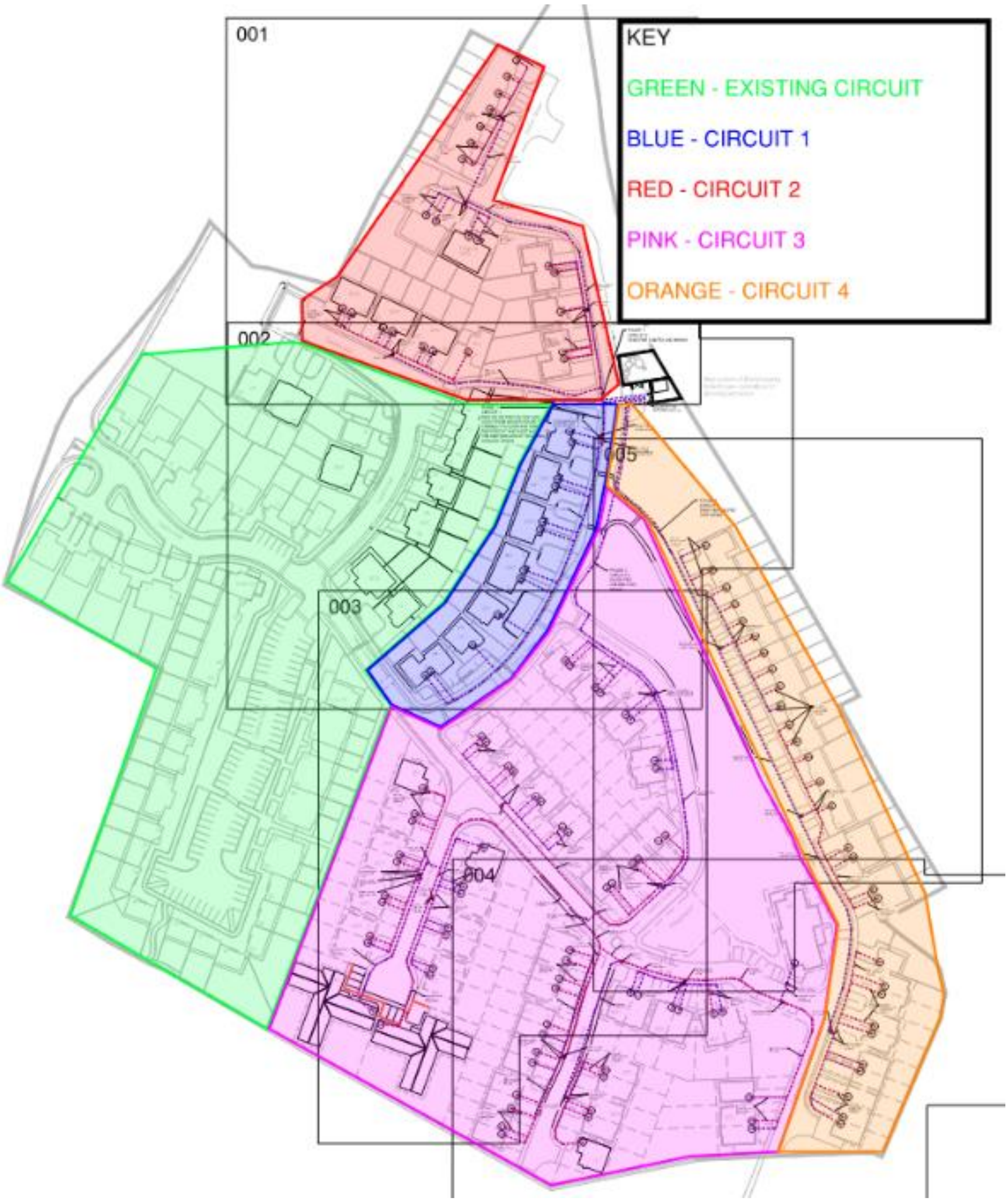
3. EXISTING HEAT NETWORK AND BUILDING CONNECTIONS

3.1 HEAT NETWORK

The heat network at Carlinn Hall was installed in phases from 2007-08 when the first phase was constructed, through to 2017-18 when the final phases were installed along with the completion of the scheme – See Appendix 1 for Google Earth ™ images of the construction of the site.

The network, as we currently understand it to be configured, along with the phases of network being developed (key in top right of image) is shown in Figure 13. Note there are five areas highlighted in Figure 13 but only four circuits (with four pump-sets in the energy centre). From information gathered during the site visit, it appeared that the "existing circuit" could be supplied by either circuit 1 or circuit 2.

Figure 13: Heat network with phases of implementation. This is based on data provided by SEAI on the project and cross-referenced with information gathered in the plant room. Note that the actual pipework for the "existing circuit" is not shown on the drawing that this figure is based upon.



After the first phase of house building, which included Carlinn Hall (street name) and Carlinn Court, house building stopped due to the global recession. Our current understanding of the network is that the original phase of pipework was installed as steel pipework, whilst the future phases of construction used Calpex DUO/UNO Polyethylene (PEX) pipework. Access to viewing manholes was not made possible during the site visit on the 18th of November 2022, so the assumptions on the pipework and its condition could not be confirmed.

3.1.1 Building connections

Each building that is connected to the heat network is connected via a metered HIU. The HIU will typically contain an ultrasonic heat meter and combination of plate heat exchangers for space heating and DHW as well as control valves and thermostatically controlled bypasses. The primary input to the HIU is the connection from the heat network, and the secondary side is the building hydronic circuits.

The network O&M provider is contracted by the Owners Management Company (OMC) to operate and maintain the network. The network O&M provider has responsibility for ensuring the energy centre and associated equipment is maintained and operating efficiently and has responsibility for the operation of the heat network up to the meter in the house – but does not have responsibility for the maintenance and upkeep of individual HIUs – the responsibility of HIU maintenance is on the property owner[23]. This is not typical best practice, as advice given in the CIBSE Code of Practice CP1[24] (best practice guidance is reference to the Heat Trust scheme (https://www.heattrust.org). Within the best practice guidance for HIUs it outlines:

- *A Registered Participant shall ensure that each HIU shall be inspected and maintained as recommended under the HIU manufacturer's guidelines or at least once every 24 months (whichever is more stringent).*
- *"Each Registered Participant shall make arrangements with the Heat Customer or other third party to enable access to the HIU to undertake inspection and maintenance activities…"*

Thus, the best practice route to maintaining a well-performing network and of operation and maintenance typically will mean that the heat network operator/owner will have the responsibility to maintain the HIUs (this will be charged for as part of annual servicing agreements or alternatives etc). As the network O&M provider do not have management control over the HIUs within each property, they are unable to ensure that the HIUs are inspected and maintained as required. This can lead to incidences of poor network performance where HIUs may bypass heat that is delivered to the property, which will lead to higher return temperatures and reduced temperature differentials (herein referred to as "delta-Ts").

Access for evaluation of these HIUs was not possible during the site visit, and images and configuration of the HIUs was not possible to be provided. It is our understanding that in each property, each HIU supplies the heating circuit and DHW loads. There are no DHW calorifiers installed in each property. The heat emitter systems were outlined to be underfloor heating (UFH) by the network O&M operator, but this was not confirmed. It is our expectation that the emitter systems in each property will be a combination of UFH and standard radiators. It is imperative that further site visits that allow for access into buildings that are connected to the heat network are undertaken, to identify faulty HIUs as well as providing better understanding of the building-level circuits.

It is recommended that a further site visit is undertaken. This site visit should prioritise assessing properties on the network to review HIU performance, emitters & DHW systems. It should also allow access to manholes on the network for inspection.

[23] The OMC as the heat provider clearly has responsibility for the heat meters. No evidence of regular maintenance checks was found. It is presumed that such activities would be instructed to the O&M provide ad-hoc, as and when an unusual meter reading or customer feedback on the meter was received.

[24] https://www.cibse.org/knowledge-research/knowledge-portal/heat-networks-code-of-practice-for-the-uk-cp1-2020

3.1.2 Hydraulic modelling

A hydraulic model of the existing network, based on the layout in Figure 13 was undertaken using in-house Ricardo tools. The purpose of constructing this hydraulic model is to estimate heat network losses and enable the network delta-T to be calculated; it also supported the validation of our network peak heat demand.

The existing meter data gives us a crude estimate on network heat losses by making an assumption on boiler efficiency. The purpose of this model was to provide a second means of calculating these losses and ensure that significantly erroneous data did was not present in the meter readings. A secondary purpose was to carry-out a verification of pipe sizing, to allow us to understand the original design philosophy and network design flow and return temperature. Finally, this provides us with a model to undertake scenario changes, i.e., what is the impact on heat losses of changing certain parameters.

The hydraulic model plots all segments of pipe network. It takes into consideration the anticipated demands on each section or node of the network and uses a diversified demand approach[25] to determine network flow rates on each section of pipework. Most pipework sizes are known and are used to calculate heat losses. Our hydraulic model produced the outputs shown in Table 3.

Table 3: Hydraulic model inputs and outputs for the Carlinn Hall heat network

	Value	Unit
Project Summary		
Total Network Length	5,282	m
Below Ground Length	4,620	m
Network Water Content	19	m^3
Network Heat Losses		
Heat Losses, Annual	573	MWh
Heat Losses, Daily Winter	1,649	kWh
Heat Losses, Daily Summer	1,408	kWh
Heat Losses as % of load	36.4 %	

Comparing the pipe sizes identified on-site to our hydraulic model, we confirmed that a design temperature of 20 degrees delta in temperature (delta-T) would have been used. This is, relatively speaking, common practice based on the age of the system and observed system temperatures. From site findings, we know that the system was actually operating at a delta-T of 10 degC – we subsequently then calibrated our hydraulic model to reflect this. This results in a higher annual mean return temperature than the system is designed to deliver It is critical for heat networks to ensure that pipework is not oversized which can have a major impact on network performance through high heat losses, excessive distribution (pumping) loads and high upfront capital cost.

We have calibrated the hydraulic model to reflect the actual flow temperature and an annual mean return temperature of 10 degC less than this. This is a higher return temperature than what we suppose the original design was based upon but reflects site observations.

The network pipework should have been sized appropriately to carry enough fluid to cope with peak heating and hot water loads at the HIU terminal. There were no discussions with either SEAI or the network O&M provider that indicated the pipework was not sized to deliver these peak loads (i.e., no instances of buildings on the heat network being able to be fully heated when needed).

[25] Diversity on a heat network refers to the levelling out of peak system demands that can be calculated for space heating and DHW. It is calculated as a means of outlining that all peak demand will not occur simultaneously.

The peak load is unlikely to be a summation of the instantaneous peak household demands because it is highly unlikely that all households will have called for heat/DHW simultaneously, this is the system diversity (or diversified demand).

A common set of data is widely used based on the Danish textbook, *"Heat Stability"*[26] which is the approach outlined in CIBSE Heat Networks Design Guide and these rules of thumb were used in this project to determine the system diversity on the network. We have assumed:

- Space heating new build peak demand 8kW
- DHW peak demand 30kW

These figures are used to produce our diversity assumptions, shown in Figure 14

Figure 14: Diversification Assumptions, Carlinn Hall (blue – space heating, orange- DHW)

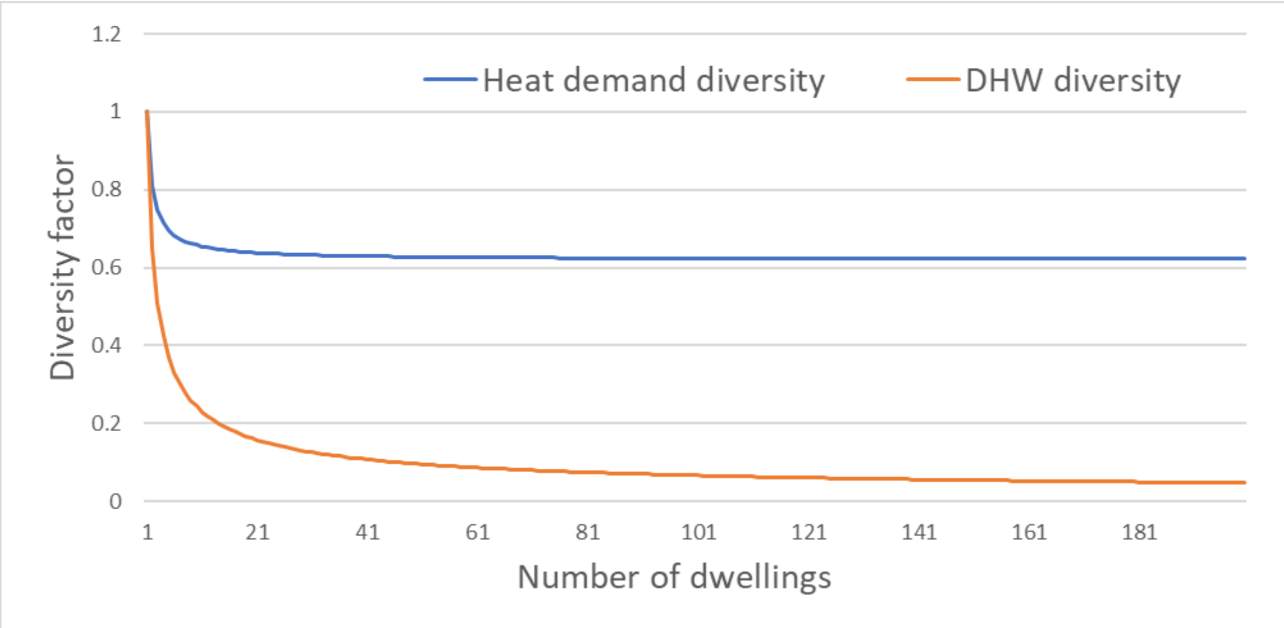


Figure 14 shows that the network is fully diversified for space heating once around 30 properties are connected, for DHW this starts to level out after around 80-90 properties are on the network (i.e., the diversity factors in Figure 14 remain constant at these levels of connected properties). As we have 178 properties on the heat network, we then assume that the diversified peak space heating and DHW loads are:

- Space heating 178 x 8 x 0.62 = 886 kW
- DHW peak demand 178 x 30 x 0.05 = 268 kW
- TOTAL diversified peak load = 1,154 kW

This correlates with our peak demand shown on Figure 10 and Figure 11 of ~1.2 MW.

We calculate the diversity of each section of pipework using the diversity factors in Figure 14 and the number of properties connected to the heat network to calculate the flowrates required to meet the demands. The resulting flowrates are used indirectly in our study. Firstly, we use the flowrates and the existing pipe sizes to help confirm the original design delta-T.

Secondly, our hydraulic model allows us to explore scenarios, i.e., does the existing network have sufficient pipe size capacity to deliver lower delta-T heat throughout the year, as might be seen in a lower temperature network that this study is investigating. The model showed no significant areas of under-sizing of pipework.

The model showed a number of areas of main spine run that were a size or two oversized, perhaps indicating that the design diversity assumptions were perhaps less aggressive than a more mature heat network market is now making. Critically however, final connections and branch runs to groups of dwellings were all at the size

[26] Lauritsen AB (ed.) (2015) *Varme Ståbi* (7th edn) (Odense: Praxis – Nyt Teknisk Forlag)

we would expect. We conclude that any design option that relied on lower delta-Ts throughout the year (e.g., ambient networks typically operate at delta-T of 5 degC) would require significant pipework replacement. The final connections into households would be problematic to implement as the pipework will arrive at the dwelling from under the floor slab, making it very costly to physically remove the existing pipework and install any new pipework.

Adjusting the diversified hydraulic model to represent an ambient network operating a delta-T of 5 degC (i.e., the pipework route lengths remain the same, but the approximate take-offs (Appendix 6) change due to the different delta-T operating conditions) results in the following **approximate** network upgrade costs:

- Pre-insulated Pipework Cost £1,380,000
- Civils Cost £2,240,000
- Building Pipework Cost £270,000
- **Total** **£3,880,000**

3.1.3 Current network performance

From the analysis in section 2 of this report, we know that the heat network and the associated generation systems are not performing near to the original design conditions. The "efficiency" of the overall system as described in section 2 is a term that is used by the network operator to determine heat billing. This efficiency encapsulates all losses on the network, be that generation losses from the fired gas boilers or CHP, heat losses from the network, or unwanted losses from poor interface performance[27].

There are heat meters installed in the energy centre that could be used to record generation and network efficiency more accurately - if they were configured to collect this data. It is recommended that these heat meters are correctly configured to allow for this data collection, this can be used for reporting trends in energy consumption.

One of the key features (amongst other key elements) of a heat network operating successfully is to maintain as large a flow/return delta-T on the network as possible – our assumption is that the network will have been designed to operate at a delta-T of 20 degC The overall performance of a system is directly affected by this temperature differential; low temperature differential means that heat is not being consumed by HIUs and may rather be being bypassed by the control valve within the HIU. This can be caused by valve failure, controls override, dirt or inappropriate original design / manufacture process; invasive inspection of the units would be required to ascertain.

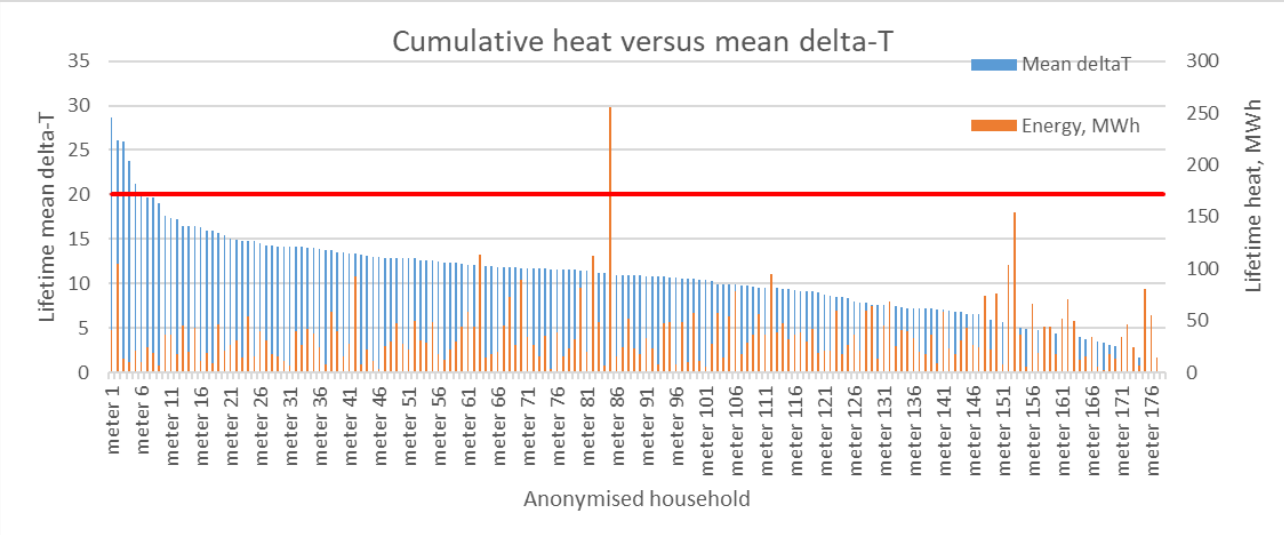
Data was provided by the network O&M provider that showed the latest gathered radio heat meter. At the time of writing, only a single month (September 2022) was provided, this shows, for each property/HIU connected to the system:

- Address (anonymised in this report)
- Time of reading
- Energy (kWh or MWh)
- Volume (m^3)
- Flow temp (degC)
- Return temp (degC)
- Meter Reference # (serial number)

[27] The original design provided for greater granularity in heat metering. There is a heat meter showing total heat generation, and a CHP heat meter. Downstream three of the four secondary circuits (1-3, not the 4th (newest)) have heat meters. Heat generation efficiency could be accurately calculated by taking the heat meter readings in the energy centre and comparing this to gas incomer data. However, not all meters are working, and their data has not been regularly logged and exported. They can provide no usable data until controls upgrades are undertaken. Thus, we have relied on the method previously set out for assessing performance.

This was used to determine, on a cumulative basis, the heat consumed for each HIU against the mean delta-T across the HIU (calculated from the measured cumulative energy usage and the measured cumulative waterflow). This is only a spot check and cannot be used to show where performance is deteriorating gradually etc – this is shown in Figure 15.

Figure 15: Cumulative network performance. Red line indicates the design delta-T of 20 degrees C.



This cumulative analysis shows a number of things. Against a design condition of 20 degrees delta-T (red line in Fig 15), we have:

- 5 HIUs performing better than design conditions (delta-T 20 degC)
- Approximately 5 HIUs performing at design conditions (20-18 degC delta-T)
- The rest have varying levels of performance, with 16 operating at 18-20degC delta-T
    - **45% have a delta-T of 10 degC or less**

This identifies one of the challenges facing the Carlinn Hall network. Not only is it in a relatively low heat density area, but it also faces certain operation and management issues. The root cause of the observed high return temperatures cannot be pinpointed on a single or few poorly performing HIUs, the vast majority of these are not performing as designed. Essentially the network is not controlling the volume of water being pumped through the estate, nor has any control over the resulting return temperature.

To have a successfully operating, decarbonised heat network in the future the network should be brought under control. This will be critical if the future decarbonisation solution includes heat pump technologies, which require the large delta-T in order to operate at their design efficiency. This differs from the existing gas-fired boilers, or indeed a biomass supplied system. Such heat generation is less sensitive to fluid temperature as, outside of condensation, their efficiency is not governed by temperature, and they are more flexible in operating with higher variations in delta-T.

It is relatively easy to draw the connection between the poorly performing HIUs and the lack of centrally controlled and robust HIU maintenance. The network O&M provider, regardless of their efforts, cannot influence the root cause of these issues.

4. SITE CONSIDERATIONS

4.1 ENERGY CENTRE EQUIPMENT & LOCATION

Table 4 shows the key energy consuming/ heat generation equipment information within the energy centre. Note ancillary plant (expansion vessels, pressurisation systems) are not listed below, but there were no clear or obvious issues with their condition (no leaks, faults etc) noted.

Table 4 : Plant room equipment

Equipment	Make & model	Output	Condition	Other notes
2 x gas fired boilers	Die Dietrich C630 -1300 ECO	1,220 kW (output) Flow temp 58-60degC	Both good/fair	
2 x Combined Heat and Power (CHP) units w/ side mounted control panel	EC XRGI	10-20 kW (power) 25 -40kW (heat)	Unit 1 – fair Unit 2 – not operational	Has own heat meter*, not installed
2 x CHP buffer vessels	EC1000P-6bar	957 litres	Good/fair	
Boiler primary pump set (twin head)	TEE	1.5 kW (each head), direct drive	Good/fair	
Secondary pump set (circuit 1, twin head)	WILO DP-E 40	4.6 kW (each head), VSD drive Flow temp: 58degC Return temp:49degC dT: 9	Good / fair	VSD – set on constant head (17 h/m); not varying in operation due to HIUs Leg has its own heat meter
Secondary pump set (circuit 2, twin head)	WILO DP-E 40	1.5 kW (each head), VSD drive Flow temp:58degC Return temp:47degC dT:11	Good / fair	VSD – set on constant head (17 h/m); not varying in operation due to HIUs Leg has its own heat meter
Secondary pump set (circuit 3, twin head)	WILO DP-E 40	3.0 kW (each head), VSD drive Flow temp:58degC Return temp:51degC dT:7	Good / fair	VSD – set on constant head (17 h/m); not varying in operation due to HIUs Leg has its own heat meter
Secondary pump set (circuit 4, twin head)	WILO DP-E 40	2.2 kW (each head), VSD drive Flow temp:58degC Return temp:50degC dT:8**	Good	VSD – set on constant head (8 h/m); not varying in operation due to HIUs Leg has its own heat meter

*All heat meters are Danfoss Sonometer 1100 Ultrasonic heat meters

**No heat meter, temperatures measured with digital thermometer on-site.

The pumps serving three branches are all currently set to operate at the same constant head despite having variable speed drives (VSD). While the HIU operation means that the pumps are not able to operate at variable head, which would reduce their energy demand, it is also very unlikely that the optimal constant head is the same for all three. The reasons for these identical settings could not be determined but it is possible that either:

1) they were commissioned in line with CIBSE Commissioning Guidance, but those settings have been lost, or
2) they were not commissioned in line with CIBSE Commissioning Guidance

Correct commissioning of these pumps could reduce their energy consumption and bring the temperature difference closer to the design conditions. However, it would be important to consider any other changes proposed prior to planning the re-commissioning to maximise potential benefits.

4.2 PIPE ROUTING

No modifications to the pipe routing have been developed in this study. The existing network has been installed over the course of the last 5-15 years with the development of the housing estate – and the housing estate is now complete in terms of all construction work. As there are no significant sections of heat network piping that have been installed to areas on the estate where no houses have been built (which we would recommend should be valved-off and removed from the network) – no significant changes to the physical pipework are expected to be necessary or recommended as part of this study. For reference, the Carlinn Hall heat network is a 3rd generation heat network; typically meaning flow temperatures <100 degC, the use of pre-insulated pipework and sub-stations with metering and monitoring installed.

A low (ambient) temperature network, often referred to as a 5th generation heat network, involves a heat pump in each dwelling which take heat from a common system operating at lower temperatures - around the ambient ground temperature. The network is provided with heat by a common low temperature heat source, such as an array of closed loop boreholes. These types of heat networks are usually limited to operating at lower temperature differences due to the temperatures which can be provided by ground loops. They also require antifreeze at significant concentrations to avoid the heat transfer fluid freezing. This reduces the heat capacity of the working fluid.

These issues combined means 5th generation heat networks need higher flow rates and larger pipework than 3rd or 4th generation heat networks. If such a system were to be considered on this site, it would require a complete re-design of the heat network which is not proposed in this report.

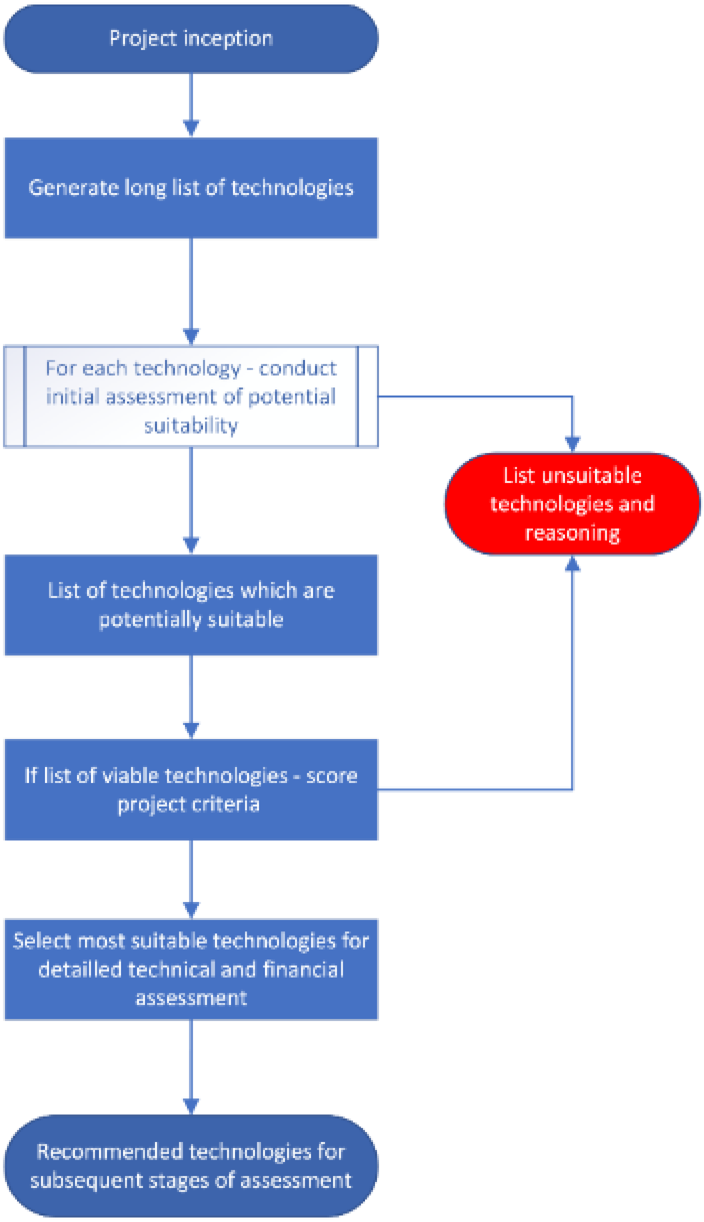
4.3 HEAT OPPORTUNITY IDENTIFICATION

The process of determining suitable alternative heat sources for a heat network (or even on a building level assessment) is to determine a long-list of technologies and then systematically determine if these technologies are suitable at the specific site before investing too much time and resources into the project. Considering alternatives to heat networks, such as using individual heat pumps in each dwelling, are not in the scope of this report.

4.3.1 Process

To develop a long list as part of the assessment of potential decarbonisation solutions for this (and any other) heat network, we must first draw up a list of potential technologies (long-listing) and whittle these down to a short-list of technologies that we will consider taking through to the modelling stage. The process for undertaking this is shown in Figure 16,

Figure 16: Assessment of technologies flow diagram



4.3.2 List of technologies

The technologies that could be considered to progress the site towards a decarbonised solution are shown in Table 5.

Table 5: Long list of technologies

Technology	Included	Reasoning
Geothermal technologies		
Centralised shallow ground source heat pump (closed loop borehole)	Yes	
Centralised shallow ground source heat pump (closed loop horizontal trenches)	No	Insufficient space – see section 5

Technology	Included	Reasoning
Centralised shallow ground source heat pump (open loop borehole)	No	Mapping indicates site is not suitable for open loop system – lack of ground water source.
Decentralised shallow shared-loop system	No	Not economically justifiable due to network modifications (required estimated at ~€3.5 -4m (pipe take-off lengths provided in Appendix 6) – this does not include borehole array costs.
Deep geothermal	No	Out of scope
Other technologies		
Centralised air source heat pump	Yes	
Water source heat pump	No	Not near body of water
Biomass (wood chip) or (wood pellet)	Yes	Pellet selected in the modelling
Electrode boilers	No	Could be used as peaking plant in full electrified solution, would result in very high cost of heat if sole technology (1 unit electricity= 1 unit heat compared to 1 unit electricity = 2 - 4 units heat for a heat pump solution)
Using waste heat from neighbouring industry/processes	No	No waste heat source identified nearby
Solar thermal	No	Solar thermal is not capable of meeting a significant proportion of the heat demand of the network as heat output in winter is minimal.
Hybrid solutions	All of our scenarios include back-up/peak generation from an alternative heat source	All these scenarios allow for the most affordable, efficient sizing/design for each of the proposed low-carbon options then using flexibility of gas to cover the peaks at varying levels.
Individual air-source heat pumps	No - out of scope	This solution would be an alternative option to a heat network during design stages or potentially at end of usable network lifetime.

There are clearly technologies that we quickly remove from the long-list based on geographical location (water source heat pumps and using waste heat from neighbouring processes or high-level financial constraints (electrode boilers (high operational costs)). Hybrid solutions would entail using more than one technology to generate the heat demand at the site, which ultimately has been undertaken as part of the analysis in section 6, page 51).

4.3.3 Short-list

After undertaking our long-listing approach, we shortlisted the following technological approaches to take through to our modelling stage.

- Centralised ground-source (borehole) heat pump
- Centralised air-source heat pump
- Centralised biomass system

Options for individual heating systems to meet the heating requirements of each dwelling, in place of the heat network are not in the scope of this report.

These scenarios are added to our business as usual (BAU) scenario for the site and are included in section 6 (energy modelling) on page 51. Some technologies have been ruled out for various reasons, given below:

- Centralised open-loop borehole heat pump
  - Presence of no aquifer means that an open loop system would not be a viable option, outlined in section 5.
- Centralised/decentralised closed loop horizontal heat pump
  - Not enough space available (see section 5).
- Shared-ground loop systems
  - Designed for very low delta-T's of ~ 5 degC. This means the pipework that is currently installed would not be suitable for this type of system. To achieve the required peak flowrates significant amounts of the network pipework, particularly the final house connections, would have to be replaced[28].
  - High capital cost for replacing all heat network piping including buried and interface (property level) pipework. Using our hydraulic model, we have estimated this cost to be in the range of €3-4M. While some of the existing main spine pipework could be re-used, the final connections would be challenging to remove and replace in situ.
- Deep geothermal
  - Out of scope for this report, but some narrative has been added to sections 4.3.5 and 5.2.

4.3.4 Available space for expansion

A decarbonised heat generation source for this network, be it from a heat pump (air or ground) or biomass will need additional space for equipment. The current energy centre measures (internal dimensions) ~ 8.9 x 5.5m leaving very minimal space for any additional equipment, which includes space for electrical infrastructure upgrades for any electrified solutions. There is some space around the energy centre that might be able to be used for a number of purposes, but also a number of prohibitive spaces, as shown in Figure 17. Equipment that would need to be installed with the chosen decarbonisation solutions includes:

- Thermal storage, this can be located externally (heat pumps & biomass)
- Acoustic enclosure for external air-source heat pump components
- Fuel handling and storage (biomass)

There is some green-space adjacent to the existing energy centre on both the north and the south sides, see Figure 17. Additional equipment takes up additional space externally, approximately 50-100m^2 depending on the scenario – however access will always be required at the site, and so whilst it would be reconfigured, there is space next to the current energy centre that will always be needed for parking. This is accentuated for biomass options, where the fuel is delivered to site, and associated space for turning of vehicles and unloading of fuel is required. The area highlighted green as "works area" is an area to the north of the energy centre which is currently not used for anything other than storage, it is assumed that this area was flattened and reinforced when the energy centre was built with biomass as part of that decision making.
The location of any external ASHP plant would need to take into consideration the proximity of adjacent houses. If located on the north-side of the existing energy centre, this is approximately 60 feet from the nearest dwelling -if on the south-side of the energy centre – the nearest dwelling is ~100 feet away. The location of external plant and the risk of noise is a key design risk that would need to be mitigated by using low noise heat pumps, additional sound attenuation devices, or both.

[28] Theoretically thermal storage can reduce this impact, but we have seen no evidence to support the dwellings having substantial space for such storage

Figure 17: Locations adjacent to the existing energy centre that would need to be used for decarbonised solution

4.3.5 Additional sources of heat/opportunities

As part of a wider assessment of resource for a heat network, additional sources of heat and opportunities for phasing of future networks should be included. Louth County Council nominated the town of Dundalk as a *"Decarbonising Zone"* under Ireland's Climate Action Plan[29]. A decarbonising zone is defined as:

"A Decarbonising Zone is an area spatially identified by the local authority, in which a range of climate mitigation measures can co-exist to address local low carbon energy, greenhouse gas emissions and climate needs"[30]

This means that there is wider interest in decarbonising heat & power beyond the scope of this project. It does however mean that decarbonising the existing network would in theory be technically supported by Louth County Council. Wider considerations for this area of Dundalk include:

- Integrating the heat network into a wider heat network
  - Carlinn Hall is adjacent to a number of other buildings/campuses which would be useful as anchor loads on a wider heat network if one was ever to be developed, these buildings are within a 500m radius of the existing energy centre)
    - Dundalk Institute of Technology (DKIT) campus (including Green Park student accommodation (constructed ~2005))
    - Crown Plaza hotel[31] (constructed ~2007)
    - Green Park residential care home (constructed ~2021)
- Deep/medium geothermal
  - It is understood that a deep/medium research borehole of approximately 400m depth is planned in the near future in Dundalk Institute of Technology (DKIT) adjacent to Carlinn Hall.

[29] https://www.louthcoco.ie/en/services/environment/climate-change-adaptation/decarbonisation-zone/

[30] Action 25c of the Government's Interim Climate Actions 2021.

[31] It is believed that the Crowne Plaza hotel, when constructed had future connection to a heat network included as part of the construction and development, which has been confirmed by members of Louth County Council, however no hard evidence of this has been provided as part of this study.

If this borehole goes ahead, then this will allow for a greater understanding of local geological environments up to a much deeper depth than has previously been known in the area. This may in turn lead DKIT to develop their own heat networking opportunities or allow for a more accurate allowance of geothermal heat availability at Carlinn Hall to be developed.

4.4 BASE CASE AND BUSINESS AS USUAL (BAU) CASE

We have developed a Business As Usual (BAU) scenario which is largely based on our base case. Our base case is based on the existing gas and heat demands provided for 2021 which has been normalised (i.e., this is not the actual gas and heat sale data provided for 2021) using a degree-day approach.

This is the data-set in which all other heat demand profiles and energy modelling is based.

Table 6: Base Case Demands – normalised figures used in modelling

Parameter	Value	Units
Natural gas demand	2,414,020	kWh/year
Heat sales	1,269,292	kWh/year
Estimated network heat losses	572,972*	kWh/year
Sales + losses (network demand)	1,842,265	kWh/year

* Calculated based on our hydraulic model

Business as usual (normalised) – with controls upgrades

Our BAU scenario has been developed based on the data in Table 6 but includes the planned upgrades to the controls as discussed with the network O&M provider. This process has reduced the natural gas demand (and thus the network demand but retains the same values for the heat sales as the purpose of the controls work is to reduce the network energy consumption. The scenario encapsulates these control upgrades, but retains the natural gas supplied fired boilers and CHP units.

Table 7: Business As Usual Case Demands and Assumptions – post BEMS control upgrade work

Parameter	Value	Units
Natural gas demand	2,401,229	kWh
Heat sales	1,269,292	kWh
Post-controls upgrade network losses	563,616*	kWh/year
Sales + losses (network demand)	1,832,909	kWh/year
Controls upgrade (planned)	2023	year

*Based on a reduced mean heat network temperature possible by upgrading the controls system (the Building Energy Management System, BEMS), represents the likely investment pathway of the BAU, or “do-minimum” approach. Recovering the full BEMS facility will allow the network to revert back to varying the night-time temperature downwards to make a (marginal) saving on heat losses. We note that this mode of operation does lead to the risk of complaints should residents use significant hot water over these time periods, and certainty would be required that the HIU operation does not result in the network actually cooling stored hot water during this operation.

In both the base-case and BAU scenarios, we assume that the energy centre equipment is replaced upon end of usable life. **This does not include the replacement of CHP 2 unit which is currently not operational** – which has been offline for 12-18 months and from our analysis does not need to be brought back-online to satisfy any electrical loads at the site.

5. SHALLOW GEOTHERMAL POTENTIAL AT SITE

As ground source heat pumps have been outlined in section 4 as suitable technologies for decarbonising the Carlinn Hall network, this chapter outlines the shallow geothermal potential at the site. The analysis in this chapter provides insight into sizing of ground-array systems, that feeds through into the energy analysis and techno-economic modelling.

5.1 PROPORTION OF HEAT EXTRACTED FROM THE GROUND

The heat provided by a ground source heat pump to a heating system includes both heats extracted from the ground and the energy from the electrical input, converted to heat.

$$\textit{Heat output from heat pump (kW)} = \textit{heat extracted from ground (kW)} + \textit{electricity input to heat pump (kW)}$$

The coefficient of performance of a heat pump (COP) is the ratio of heat output to electricity input:

$$\textit{Coefficient of Performance} = \textit{Heat output from heat pump (kW)} \div \textit{electricity input to heat pump (kW).}$$

Therefore, the heat output required from a ground array is given by:

$$\textit{Heat output from ground} = \textit{Heat pump heat output (kW)} \div \textit{heat pump COP}$$

A heat pump operating at a higher coefficient of performance reduces the electricity consumption and operating costs. It also results in a greater proportion of heat being extracted from the ground than a system operating at a lower COP. The COP used should be the highest that the heat pump can reasonably be expected to operate at, when supplying peak heat output.

This ratio varies throughout the year depending upon a number of factors. The seasonal average of coefficient of performance (sCOP) describes the average COP over a year. The total heat extracted from the ground array is given by:

$$\textit{Total heat extracted from the ground (kWh)} = \textit{Total heat output from heat pump per year (kWh)} \div \textit{sCOP}$$

When considering the values used in the initial design stage of a GSHP system, it is important to ensure that the ground array is of sufficient size to meet the existing and future heat demands as well as ensuring that it can continue to operate effectively if improvements to the system over time allow it to operate at a higher COP or sCOP.

The above calculations hold true for all heat pump solutions, but the source of heat will change depending on the specific type of system installed (air, water, ground etc).

The approach outlined above is outlined in SR 50:4:2021 Heat Pump systems in dwellings[32] - however this is still a high-level rule of thumb for initial viability and is meant for systems up to a capacity of 45 kW_{th}. SR 50:4 outlines that for borehole design pr17522 (design and construction of borehole heat exchangers) should be followed (note that when SR 50:4 was written, this was a provisional (pr) standard, it is now a full European Standard EN 17522, but it has not yet been translated into an Irish equivalent standard (IS EN)). There are a number of reasons that a conservative approach is required when translating these methods into the calculations for a heat network:

[32] https://shop.standards.ie/en-ie/standards/s-r-50-4-2021-1210946_saig_nsai_nsai_2932704

1. The choice of COP and sCOP when calculating a borehole field is intrinsically linked to the size of the array calculated. A higher COP/sCOP should be used to avoid under-sizing the borehole array. An under-sized array has much higher risk that it could fail to provide adequate heat to the heat pump system, which can lead to system failure if not managed correctly. The best way to avoid these risks at the design stage is to ensure the borehole array has sufficient capacity for the heat load it is to provide.
2. SR 40:4 is designed for use for dwellings up to 45kW$_{th}$ and for single dwellings – these have seasonal heating demands that mean comparatively little heat would be extracted during summer periods. By contrast, while the heat network serves lower demands in summer, the network is energised and therefore the heat pump system would still be required to overcome the heat losses from the network itself. This again means that a conservative approach to sizing the borehole array is recommended.

5.2 BACKGROUND ON RETROFITTING GEOTHERMAL

Naturally occurring heat from the subsurface can be used to provide heat to buildings or heat networks in one of a number of ways:

- Shallow geothermal energy – where heat is extracted from close to the Earth's surface (usually between 1 – 200 m below ground, and up to 500 m depth) and upgraded using a heat pump to a temperature where it can be used.
- Deep geothermal energy – where a borehole is drilled to a depth where the ambient temperature is sufficient that it can meet the heating demands of the system. Based on GSI's deep temperature maps[33] for Ireland it appears that a depth of at least 2km would be required to achieve a temperature of 60 degrees C.

Shallow geothermal

Within shallow geothermal there are a number of methods of extracting heat:

- Closed loop boreholes – vertical boreholes commonly 100m to 200m below ground level in which pipework is installed. The boreholes are connected to form a single closed hydraulic circuit from which heat is extracted by a heat pump. The working fluid is usually artificial and thermally efficient.
- Open loop boreholes – groundwater is pumped out of the ground (abstraction) and heat is extracted from the water by a heat pump. The slightly cooled groundwater can be reinjected into the ground.
- Horizontal closed loop collector – heat is extracted from loops of pipework installed in trenches of around 1 – 2 m depth.

Shallow geothermal systems can provide slightly different temperatures depending upon site geology, with the ground temperature being around 10 degC to 18 degC prior to a heat pump system being installed. The heat pump extracts heat from the ground array, and the temperature extracted in an operational system can be expected to be between 0 degC to 10 degC during the heating season - with higher temperatures on some sites, or in summer months. The heat is therefore upgraded by a heat pump to the required temperature for the network. The closer together the source temperature is to the supply temperature, the less electricity the heat pump will use to upgrade the heat and therefore the lower the energy consumption of the system. This difference is minimised through a combination of good installation and design practices on the borehole system as minimising the flow and return temperatures in the heating system.

There are some differences in the resulting energy consumption as a result of the different heat sources, with higher source temperatures resulting in lower energy consumption by the heat pump.

[33] Tellus Work Plan (gsi.ie)

Deep geothermal

The benefit of deep geothermal energy is that the energy required to operate the system is considerably lower than shallow geothermal as the temperatures supplied are higher. The exact temperature depends upon the geology and the thermal gradient on site; however, the intention would usually be for the geothermal system to meet the heat demands of the site without it being upgraded. In this case the approximate depth is in the order of 2km to 2.5km based on GSI Ireland deep geothermal temperature maps, however recent exploratory borehole in Technological University Dublin (TUD) recorded 38 degC at 1km depth.

Deep geothermal systems have a high fixed capital cost which means that they tend to be financially viable only where a sufficiently high heat demand exists, e.g., large-scale heat networks, industrial applications, etc.

5.3 DATA PROVIDED FOR THE STUDY

The geothermal subsurface desk study was provided by Geological Survey Ireland who provided a background suite of information on the geological conditions at Carlinn Hall. This information is presented in Appendix 7 and summarised below:

Geology

- Carlinn Hall is underlain by the Clontail Formation, composed of Silurian calcareous red-mica greywackes

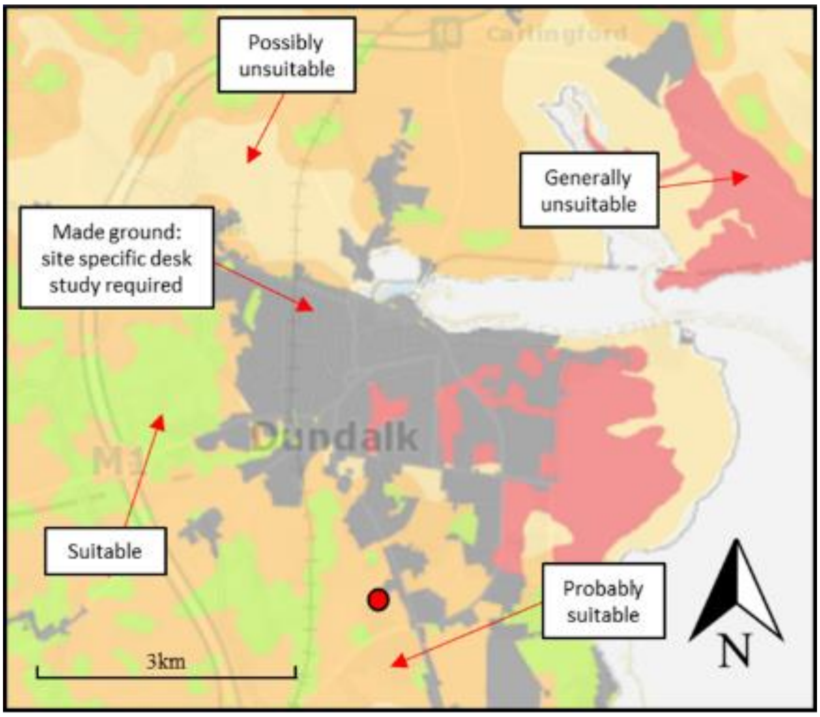
Hydrogeology

- The aquifer at this site is classified by Geological Survey Ireland as PI (Poor Aquifer - bedrock generally unproductive except for local zones).

Shallow geothermal properties

As shown in Figure 18, the site is shown on GSI mapping to be “probably suitable” for vertical closed loop GSHP. Site specific investigation by suitably qualified personnel is advised to determine the suitability. For more information see Appendix 7.

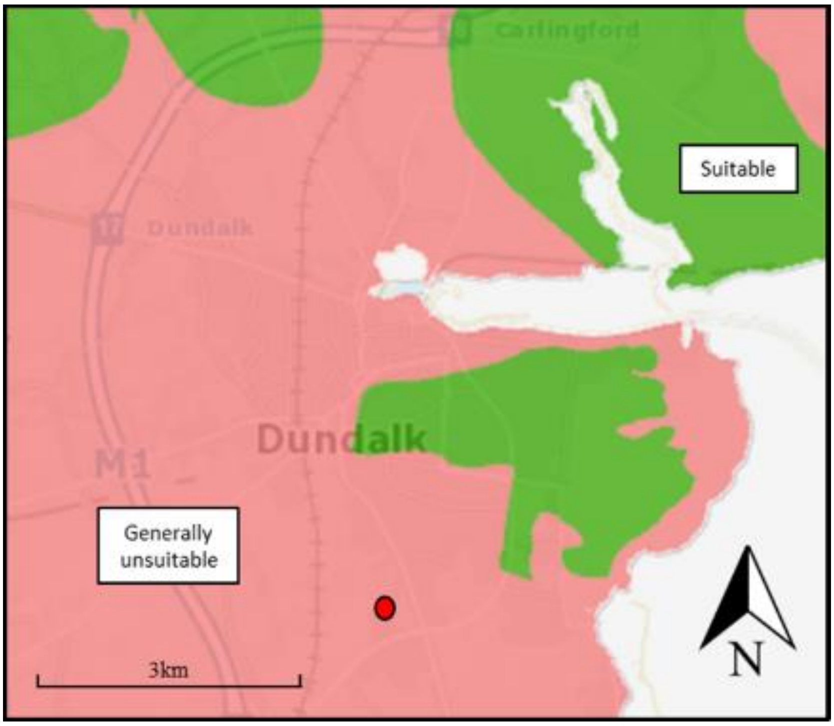
Figure 18 Map showing suitability of closed-loop geothermal systems in the surrounding area. Carlinn Hall shown in red (Source: GSI).



Open loop geothermal properties

As shown in Figure 19 below, the site is shown on GSI mapping to be “Generally unsuitable” for open loop boreholes. For more information see Appendix 7.

Figure 19 Map showing suitability of open-loop geothermal systems in the surrounding area. Carlinn Hall shown in red (Source: GSI).



As the site is on an unproductive aquifer, open loop heat pump systems were not progressed to the short list of technologies to model. Closed loop systems (vertical boreholes and horizontal trenches) can be assessed.

5.4 AVAILABLE SPACE FOR SYSTEM

There were four areas at Carlinn Hall that were identified as being potential areas where a shallow geothermal system might be able to be implemented, these are shown in Figure 20. Note that Area C in Figure 20 is beneath residents parking spaces[34], but was highlighted during the site visit, whereas areas A, B & D are all on greenspaces. The area available was estimated using the Google Earth Pro[35] Polygon tool.

[34] We would always recommend that access to the manifold of the borehole can be made for trouble-shooting and solving operational issues that could arise. Installing a borehole array under a carpark (or under a building as a comparator) may be considered to be higher risk location

[35] https://www.google.com/intl/en_uk/earth/versions/#download-pro

Figure 20: Estimated space for ground-based systems

The purpose of this stage of analysis is to identify if there is sufficient space on site to ensure a system can be designed which meets the needs of this site and achieves acceptable performance. There are many factors which affect the design of a borehole array, including:

- Depth of surface geology above bedrock
- Bedrock type(s) and thermal properties
- Whether there is any water flow in the underground – this is beneficial to recover the ground temperatures
- Presence of voids/ fractures (Drilling risk)

In relation to the cooling requirements, if there is waste heat, such as that rejected by a cooling system, then injecting that heat into the ground loops can significantly improve the time to recover ground temperatures and the temperatures that it recovers to. **This can in turn mean that fewer boreholes are required.** This is one of the key benefits of a GSHP system over an ASHP. While no waste heat source or cooling is available on site, if a detailed ground source heat pump system design were being carried out in the future it would be important to re-assess if this was the case at that point.

A test borehole is therefore of significant benefit to inform the final design, however due to capital cost of those works, it is important to understand at this stage if there is a possible solution.

In order to allow for the uncertainties outlined above and to be confident that it is possible for a borehole system being feasible we have assumed that boreholes are installed on a 10x10 grid, this means that we could install 9 boreholes in a $100m^2$ square grid. As this spacing for boreholes is based on a square grid, which clearly isn't attributable for non-standard/rectangular areas of ground – we have assumed that 75% of the land as outlined in Figure 20 would be suitable for borehole arrays. An optimal design at a later stage may allow for closer spacings or the use of more space. The number of boreholes that could be installed is shown in Table 8.

Table 8: Potential borehole capacity by defined area

	Mapped area (m^2)	Useable area (m^2) (75% of total)	Potential number of boreholes that could be installed in area
A	848	636	57
B	2,336	1,752	157
C	1,303	977	87
D	1,379	1,034	93
TOTAL	**5,866**	**4,400**	**394**

5.5 ESTIMATION OF SYSTEM HEAT EXTRACTION RATES AND CAPACITY AT SITE

5.5.1 Horizontal trenches

Guidance from the CIBSE TM 51 Guide[36] gives indicative figures for that the specific heat extraction rate from the ground for horizontal trenches is between 10- 40W/m^2, depending on the type of ground and duration of heat extraction.
The estimated heat capacity of the system (W) should be divided by the lower (10W/m^2) and upper bounds (40W/m^2) of the specific heat extraction rate to obtain an indication of the likely maximum and minimum areas (m^2) of land required for the horizontal trenches, this is shown in Table 9.

Table 9: Horizontal trench capacity, minimum and maximum output

Area	Min output, 10W/m^2 (kW)	Resulting heat pump capacity at COP 4	Max output, 40W/m^2 (kW)	Resulting heat pump capacity at COP 4
A	10	13	39	52
B	6	8	25	33
C	18	24	70	93
D	10	13	41	55
All areas	**44**	**58**	**176**	**233**

Table 9 shows that even at the maximum output conditions, the available space for a horizontal array is the limiting factor as the heat demand requirements would not be able to be met by the horizontal ground array.

5.5.2 Boreholes

5.5.2.1 Context of ground source on this system

Ground source heat pumps are a proven solution to provide low carbon heat and they have been used effectively throughout Europe, including in countries with colder winters than Ireland. There are some specific risks associated with ground source heat pump systems which needs identified and mitigated to ensure that they are reliable and as energy efficient as possible.

In sites where there is heating and cooling, such as retail buildings, airports or offices, the rejection of heat during cooling helps recover the temperatures in the ground array. This is of significant benefit in both ensuring

[36] https://www.cibse.org/knowledge-research/knowledge-portal/tm51-ground-source-heat-pumps

good performance but also avoiding the temperature in the ground array becoming so low as to cause operating problems or poor efficiency.

In systems where there is heating only, the recovery of the temperature within the ground array is solely reliant upon the flow of naturally occurring heat in the ground. This varies significantly between sites due to factors such as the presence of water, whether that water is flowing as well as the type of rock and its thermal properties. Many of those factors can only be confirmed with a high degree of certainty by drilling a test borehole or observing the results of one from a nearby site. The input of an experienced geologist at an early stage is valuable in identifying the likely ground conditions.

There are also significant differences between heat loads which affect the design between systems of equivalent capacity. If the heat load is required for short duration, then there is a greater opportunity for the ground temperatures to recover, however if heat is required for very long periods at significant levels, then there is both more heat for the ground to provide and shorter periods for it to recover.

Combining these factors means that a GSHP system on this site is likely to require significantly more boreholes than a system of similar capacity on site with shorter run hours and where waste heat from cooling could be rejected to the boreholes.

5.5.2.2 Consequences of under-performance

While every system is designed to minimise the chance of poor performance, the consequences of system not performing as intended are important to consider in determining the attitude to risk in the final design. For borehole systems over-sizing the system comes at considerable cost and is therefore undesirable. However, the consequences of under-sizing the system are not the same on every site. If, after several years of operation, the temperature in the ground loop system were to fall to a level where operation was unreliable then the options for remedying that problem could include:

- Drilling more boreholes; or
- Operating the heat pump less and backup heat sources more than planned.

On this site, all three of these options would be undesirable for the residents and the system operators. On the balance of risks therefore the risks associated with poor performance are considered to be of primary importance. A different approach to these risks could result in a smaller system size and costs, however the risks associated with doing so would need to be understood.

5.5.2.3 General approach

Once more detailed ground investigations have been carried out and subsequent detailed design of a ground loop system using details such as the depth to bedrock, detailed bedrock type(s) and presence of water then it is likely that a smaller number of boreholes less than the maximum considered in section 5.4 above. As such, while it is prudent to ensure that the site is technically capable of meeting the demand should the conditions be found to be less favourable, for the purposes of estimating the likely cost of a ground source heat pump system an approach based on the average requirements for ground source heat pumps on a site like this is used.

Considering first a general approach, the guidance from the CIBSE TM 51 Guide[37] gives indicative figures for the heat extraction rate from the ground for shallow boreholes is 20- 55 W/m, depending on the type of ground and duration of heat extraction. The heat extraction possible for varying borehole depths is shown in Table 10.

[37] https://www.cibse.org/knowledge-research/knowledge-portal/tm51-ground-source-heat-pumps

Table 10: Potential heat extraction from varying borehole depths – e.g., a 100m borehole with a heat extraction rate of 20 W/m could be expected to extract 2kW (100m x 20W/m)

Borehole depth	Heat extraction rate 20 W/m	Resulting Heat pump output at COP 4	Heat extraction rate 55 W/m	Resulting Heat pump output at COP 4
100	2 kW	2.7 kW	5.5 kW	7.3 kW
125	2.5 kW	3.3 kW	6.9 kW	9.2 kW
150	3 kW	4.0 kW	8.3 kW	11.0 kW

The estimated heat capacity of the system (W) should be divided by the lower (20W/m) and upper bounds (55W/m) of the specific heat extraction rate to obtain an indication of likely maximum and minimum total length (m) of borehole required to satisfy the peak heat demand, this is shown in Table 11. This is a rule of thumb approach that can be used to get an order of magnitude for sizing a borehole array. For the purposes of this analysis the peak heat demand of 1.2MW[38] is used rather than the heat pump capacity (the peak heat demand being a function of the network demands, whilst the heat pump capacity is evaluated based on simulation processes outlined in section 6.3).

The number of boreholes can be limited by the instantaneous heat extraction from the borehole (power), or the total heat extracted. The borehole array must be of sufficient size to ensure that at the end of a sustained period of heat extraction or at the end of the heating season, the temperatures being provided by the ground loop array must be acceptable, generally considered to be >0 degC.

The borehole depth is calculated using: *peak heating load (kW) *(COP -1) / COP)*

Using a peak heat demand of 1,200 kW and a COP of 4.0 this results in 900 kW to be delivered by the source. Table 11 shows then the array lengths that may result depending on the heat extraction rates used.

Table 11: Potential depth of borehole required to meet peak demands

Peak heat demand (kW)	Total borehole depth for heat extraction rate of 20 W/m at COP of up to 4 (metres)	Total borehole depth for heat extraction rate of 55 W/m at COP of up to 4 (metres)
1,200	45,000	16,364

If we know the overall depth of borehole that might be required, then we can estimate the number of boreholes required to satisfy that load at varying borehole depths to meet the peak space heat demand (1.2 MW), with a heat pump operating at a heat pump with a COP of up to 4, is shown in Table 12.

Table 12: Estimated number of boreholes required to meet peak demand

Borehole depth (m)	Number of boreholes required @ 20 W/m at a COP of up to 4	Number of boreholes required @ 55 W/m at a COP of up to 4
100	450	164
125	360	131
150	300	109

We can see that between 109 and 450 boreholes (depending on heat extraction rate and depth of borehole) would be required to meet the peak demand based on the information in Table 12. Comparing this against the

[38] This sizing is developed in Section 6

available space at the site (Table 8) we can see that there are borehole configurations which would allow a system of any size to meet the demand. This is clearly a large range which has significant cost implications.

The geological report states that the rock is a type of sandstone, and the thermal conductivity is typically around 2.8 W/mK with consolidated rock ranging from 1.1 to 5.5W/mK. As such the thermal conductivity is close to the average of these values. The GSI mapping shows the rock to be "Calcareous red-mica greywacke" a type of sandstone.

We would estimate a heat output of around 30W/m may be possible.

The actual size of the installation depends upon a number of factors and therefore further investigation of the ground conditions and simulation of the heat load is required at detailed design stage. For the purposes of an initial estimate therefore, the number of boreholes to satisfy the peak demand could be expected to be around the average of the 20-55W/m range, **resulting in around 200 boreholes at 150m depth. As the peak demand happens so infrequently at site, an alternative method to calculating the borehole array sizing is outlined below for comparison.**

As set out in section 6, there is potential to optimise the size of the heat generation equipment by combining it with thermal storage. **The method of approximating the size of the borehole array using the peak load is inherently conservative** and it may be possible to reduce the size of the array at detailed design stage though dynamic simulation using the results of test boreholes and the optimised heat pump sizes. An alternative approach to calculating the borehole array size uses the annual heat consumption is considered in Table 13.

The borehole array estimation calculation using this method is similar – but rather than using instantaneous heat requirements (kW), we use the annual seasonal COP (sCOP):

Borehole heat output = *heat output from heat pump x (sCOP -1/sCOP).*

This method uses an estimation of the heat delivered by the heat pump – this was simulated in Energy PRO™ - though note that the aim of the simulation modelling was to simulate a system that provided ~90% of the heat demand (the results produced a system that could provide 91%). This is a design decision and means that this method does not require detailed simulation to estimate the borehole array sizing.

Table 13: Estimated borehole array size based on annual heating demands

Parameter		Unit
Total system gas consumption	2,372	MWh
% of heat to be delivered by HP[39]	91%	
heat output from heat pump	2,159	MWh
Heat pump sCOP for outline design (Note 1)	4.0	
Heat output from boreholes (Note 2)	1,619	MWh
kWh/m limit[40]	50	kWh/m
Borehole depth	150	meters
metres of borehole (Note 3)	33,000	meters
Number of boreholes	220	boreholes

Note 1: As per sizing exercise outlined in section 5.1 – this sCOP is higher than our simulated sCOP in our modelling process but allows for a sCOP of up to this for borehole sizing.

Note 3: This figure has been rounded up to the nearest thousand

[39] This is calculated for our selected solution in section 6

[40] Based on the ground conditions and geology of rock. This is a conservative figure based on dry unconsolidated rock– adjusting this can have a significant impact on the borehole array length. Upper limits of ~100 kWh/m would result in a borehole array of half the size being required.

Using the existing heating demand of the network (which includes heat losses on the network) leads to a total of 220 boreholes and total borehole array length of 33,000 meters (this has been rounded up). This figure is of similar magnitude to that presented in Table 12 which are based on the peak demand of the network.

For the purposes of the analysis moving forward in this report, the borehole array is based on the information presented in Table 13, totalling 220 boreholes

Note that the costing is outlined in section 7. Cross-referencing this against the available space outlined in Table 8, we can see that there is enough viable space across the areas identified. It might be possible to install the entire array in areas A & B with a slightly different spacing regime, which would be the most suitable areas to use due to their adjacency to the energy centre and the ground type (soft – avoiding concreted areas). This would need to be further assessed against any dynamic simulation that would further refine the borehole array sizing.

5.5.2.4 Next steps & recommendations

In order to accurately determine the number and depth of boreholes a detailed simulation is required by a competent person to IS EN 17522.

In order for this design to be accurate, detailed heat load profile is required and therefore data monitoring of the heat network would be significantly beneficial using the existing installed heat metering.

The number of boreholes required for the final array is highly dependent upon a number of factors, such as the peak load of the system as well as the peak load duration and the total heat extracted over the heating season.

A reduction in the heat pump capacity does not necessarily result in a proportional decrease in the number of boreholes as the total heat generated over the year is relatively unchanged.

As such the next step to determine accurately the number of boreholes required would be dynamic software simulation.

It is usual to conduct an initial simulation based on desktop geological survey and then further refine the design by using a test borehole and thermal response test to obtain more accurate, site-specific results.

5.6 OVERALL FINDINGS ON SHALLOW GEOTHERMAL POTENTIAL AT SITE

Having considered a number of scenarios it does appear that there is likely to be sufficient space on site for boreholes to be considered a key solution to decarbonising the heat network at Carlinn Hall.

It is clear from Table 9 that there is insufficient space for a horizontal trench solution and so it can be disregarded.

Table 11 shows that, depending on the heat extraction rates and depths of borehole, a borehole-based system could satisfy the system loads. This may result in a substantial quantity of boreholes being required depending on the heat extraction rates that are possible; we have estimated 220 boreholes at 150m depth can satisfy the majority of the annual heating demands, and these are used in the subsequent sections of the report.

A more detailed dynamic simulation would be required to refine the potential design options, ideally this would be informed by a test borehole and thermal response test, however an initial simulation based on desktop survey may be prudent.

Test borehole

At the time of writing a text borehole is proposed at the adjacent Dundalk Institute of Technology. The borehole logs from that test borehole and thermal response testing results (if carried out) could inform a dynamic simulation of options for the number, depth and layout of boreholes and the resulting costs.

6. ENERGY ANALYSIS

6.1 OVERALL MODELLING PROCESS

Our modelling of the existing and future decarbonised heat networks is done in a combination of in-house tools - predominantly excel based analysis – for example the hydraulic model as outlined in section 3 and simulation tools – namely EnergyPro™. The outputs of this analysis are then fed through to our techno-economic model (TEM), which is outlined in section 8. Our simulations and modelling have a number of fixed and variable inputs, as outlined in Table 14 below.

Table 14: Modelling and simulation modelling inputs and outputs

Inputs		Outputs
Fixed	**Variable**	
178 dwellings	Heat source (GSHP / ASHP or biomass)	Annual energy input (fuel (electricity or biomass)
Flow temperature 59 degC	Heat source capacity (kW)	ASHP COP at different air temperatures (Figure 21)
Return temperature 50 degC	Thermal store size (m^3)	Resulting sCOP of ASHP/GSHP
Heat demand (normalised, section 2.3)	Heat sale price per technology (note 1)	
Existing boiler efficiency		
Heat losses on network (based on fixed system temps)		
Biomass boiler efficiency		
Design COP (ASHP & GSHP systems)		

Note 1: Whilst the heat sale price in reality is flexible and varies seasonably, our TEM (analysis in section 7) is an annual modelling tool that sets a fixed heat sale price per technology (as the TEM functions as an annual tool).

6.2 MODELLING SOFTWARE

Energy modelling for the alternative heat generation solutions was undertaken using EnergyPRO™ software, which enables the simulation of a heat system's performance over a given time period. The overall network heat demand was defined in Section 2. Heat losses from the network piping, where relevant, were also modelled using our hydraulic model. This ensures heat demands are accounted for; losses were assumed to occur at a constant rate over a summer period and a winter period. The next step is to assign a low carbon heat generation solution into the software and simulations are run that use differing technologies with different thermal capacities.

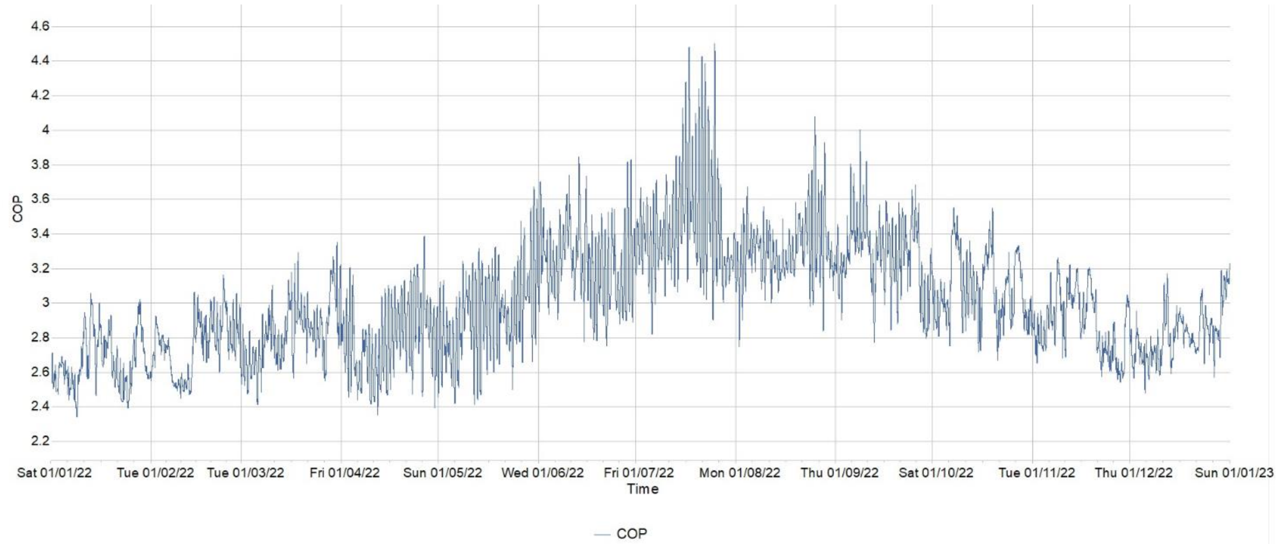
Appropriate thermal storage and back-up generation is then iteratively arrived at, and the simulation model can be run outputting a range of graphs and tables showing the whole system energy flows (generation and consumption) for the year. The model inputs can then be altered to optimise both the technical and economic performance of the system to produce an optimum solution (e.g., varying heat pump size, changing the size of the thermal store to minimise the use of electricity during red rate tariffs etc).

For heat pumps, COP data is taken from manufacturer literature at design conditions (i.e., at standard test conditions from EN 14511) and this data is used as input into the EnergyPro™ model – for our heat pump scenarios and specific model selected, this was 2.66.

The key technical parameter to establish for the modelling of the heat pumps is the seasonal coefficient of performance (sCOP), which is ratio of useful heating provided (heat out) to work required (electricity in) over the course of a year. For the air source heat pump this is generated from our model and based on the heat network flow and return temperatures, demand profile and external air temperature conditions. Typical sCOPs for heat pumps will range from 2 – 4, with the higher number reflecting a higher efficiency and better performance. The COP of a heat pump is influenced by a number of variables, including the temperature of the heat source. Thus, a fixed COP is never truly achieved in practice.

For example, the COP of an ASHP system at Carlinn Hall will vary from between 2.35 to 4.50 (Figure 21), This was generated by equating against the local weather profile for the area[41]. The EnergyPRO™ model applies local weather data to representative manufacturer's data to calculate the seasonal COP across a calendar year, and at our chosen network temperatures. The seasonal COP, sCOP of the ASHP, was calculated as 2.9 based on design temperatures of 60 degC/53 degC for flow and return, this is shown in Figure 21.

Figure 21: COP for a 350 kW ASHP over a calendar year



The ground surface of the earth is heated by solar radiation, and this varies both daily and seasonally; daily variations disperse after a few 10cms, but seasonal variations at greater depths. At depths of about 15m the temperature is approximately constant and equal to the mean annual air temperature.[42] **This leads to an improved sCOP of a ground source heat pump due to this much more consistent temperature provided by the borehole array.**

The temperature entering the heat pump from the ground array is also dependent upon the design and operation of the heat pump system, in a way which is not true of well-designed air source heat pump systems. In many ground source heat pump systems, the temperature in the ground will drop throughout the heating season due to heat being extracted and the temperature will recover during summer months.

In a well-designed system the temperature at the start of each heating season will be approximately the same. If more heat is extracted from the ground than the ground array can support, then the temperature would be lower at the start of each heating season than the preceding year **leading to a reduction in sCOP and can result in system failure if not addressed.** Therefore, in many GSHPs the long-term average ground temperature and the variation in temperature is dependent on design, operation, and monitoring regime to a greater extent than the undisturbed ground temperature.

Therefore, the seasonal average sCOP is used for GSHP analysis. Without having undertaken a detailed ground model, an equivalent fixed **figure of 3.5 was selected for the GSHP**, based on previous project

[41] Accessed from: : https://www.met.ie/climate/available-data/historical-datahttps://ec.europa.eu/eurostat/web/energy/data/database

[42] https://nora.nerc.ac.uk/id/eprint/7964/1/final_paper.pdf

experience of typical ground return temperatures[43]. Note that this is a lower sCOP value than used in indicative sizing for the borehole array outlined in section 5.
The actual temperature of the ground (and subsequent heat delivered/electrical demand through the heat pump system) will depend on the geology and presence of ground-water at the site. Note that we have added a sensitivity with an increased sCOP of the GSHP system which is in section 8.2, page 75.

The heat network that has been modelled in EnergyPRO™ and through to our TEM is based on our BAU; flow temperature of 59 degC and return temperature of 50 degC, supplying space heating and DHW to the properties (178 households) on the network. This is an improved network performance, assuming the BEMS upgrades as outlined in Section 4.4 have been incorporated.

The efficiency of the biomass boiler based on similarly sized units was taken to be 75%.

6.3 PERFORMANCE MODELLING

The capacity of the low-carbon heating technology was sized to maximise the percentage of heat delivered by the low carbon technology (with the remaining delivered by the back-up/peaking plant); i.e., this is the 1,832 MWh that the network currently supplies on an annual basis. This is based on the load duration curve shown in Figure 11. The remaining heat demand is then covered by backup gas boilers. A sensitivity has been included for cost of heat purposes that includes an electrode boiler set up (100% removal of fossil fuels) for the back-up/peaking requirement.

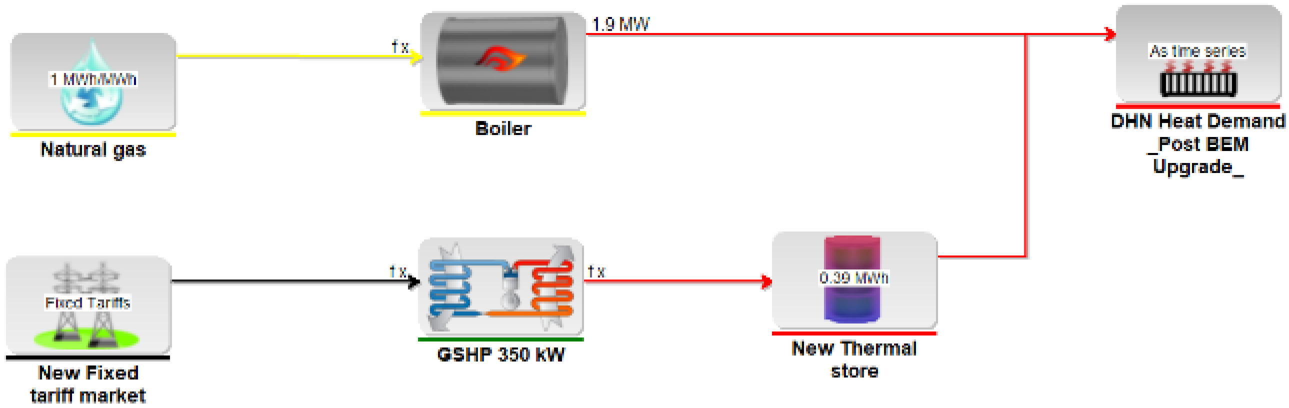
The thermal capacities modelled for each of the three technologies - ASHP, GSHP and biomass – were 250 kW, 300 kW and 350 kW.

Thermal storage was modelled to optimise the operation of the heat pumps. As well as stabilising heat pump operation at low load, it allows load spikes to be accommodated using much smaller plant, operating off-peak.

From the space available onsite and from similarly sized DHNs, a starting point of 50 m^3 was used as a reasonable estimate. From there, iterations higher and lower were used to test this sizing; 25m^3, 50m^3 and 75m^3. Normally, these tanks have a vertical cylindrical form, made of steel, and are located adjacent to the energy centre.

The energy flow diagram from EnergyPRO™ for the GSHP scenario is shown in Figure 22.

Figure 22: Energy flow diagram for GSHP scenario from EnergyPRO™



6.4 SELECTED MODELS

From the three technologies – GSHP, ASHP and biomass – 27 models were run in total comparing heating plants at 250 kW, 300 kW and 350 kW respectively: as well as thermal stores of volumes 25m^3, 50m^3 and 75m^3. From a comparison of all of these scenarios with careful analysis of the data a thermal capacity of 350

[43] Note that for the outline borehole design a COP of 4 was used to determine ground-array sizing in a conservative manner. For calculating performance, a lower sCOP has been used, again as a conservative approach to calculate the electrical input from the heat pump (note a sensitivity using a higher sCOP is presented in section 8).

kW with a thermal store of 50m^3 was considered the optimum size in terms of the overall heat generated by the low carbon heating plant and the efficiency relating to the charging and discharging of the thermal store. This was the design criteria that we have used in our techno-economic modelling of the site.

Figure 23 depicts an example of one output; the heat generated by each item of plant (i.e., the main heat generator (in green) and the peak/back-up generator (in yellow)) in the biomass scenario over the course of one year. The backup gas boilers operate at periods when there is more than 350 kW of heat demand and as such are on for ca. 1,500 hours per year. The remaining ca. 7,000 hours in the year are met almost exclusively by the main heat generation plant (heat pumps or biomass) with the exception of one hour per month and one week per year factored in as non-availability periods within the EnergyPRO™ model.

Figure 23: Load duration curve for network in the biomass scenario taken forward to techno-economic modelling stage (350kW, 50m^3 thermal store). Biomass generation is shown in green and back-up boiler generation is show in yellow.

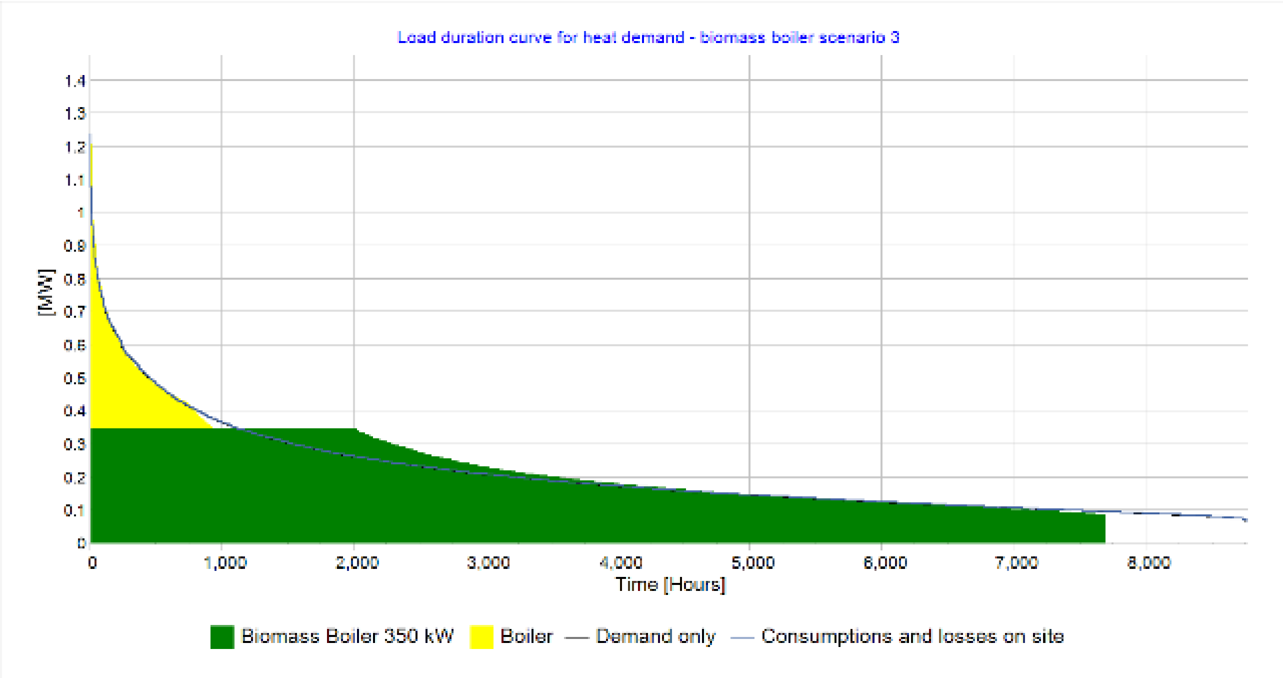


Figure 24: Typical winter week for network (Energy Pro output). The upper graph shows load in MW over time, as met by each generation type. This output shows the ASHP modelling and depicts the ASHP output shown in green and boiler generation shown in yellow. The lower graph shows the thermal storage capacity in MWh (orange line), charging and discharging over time.

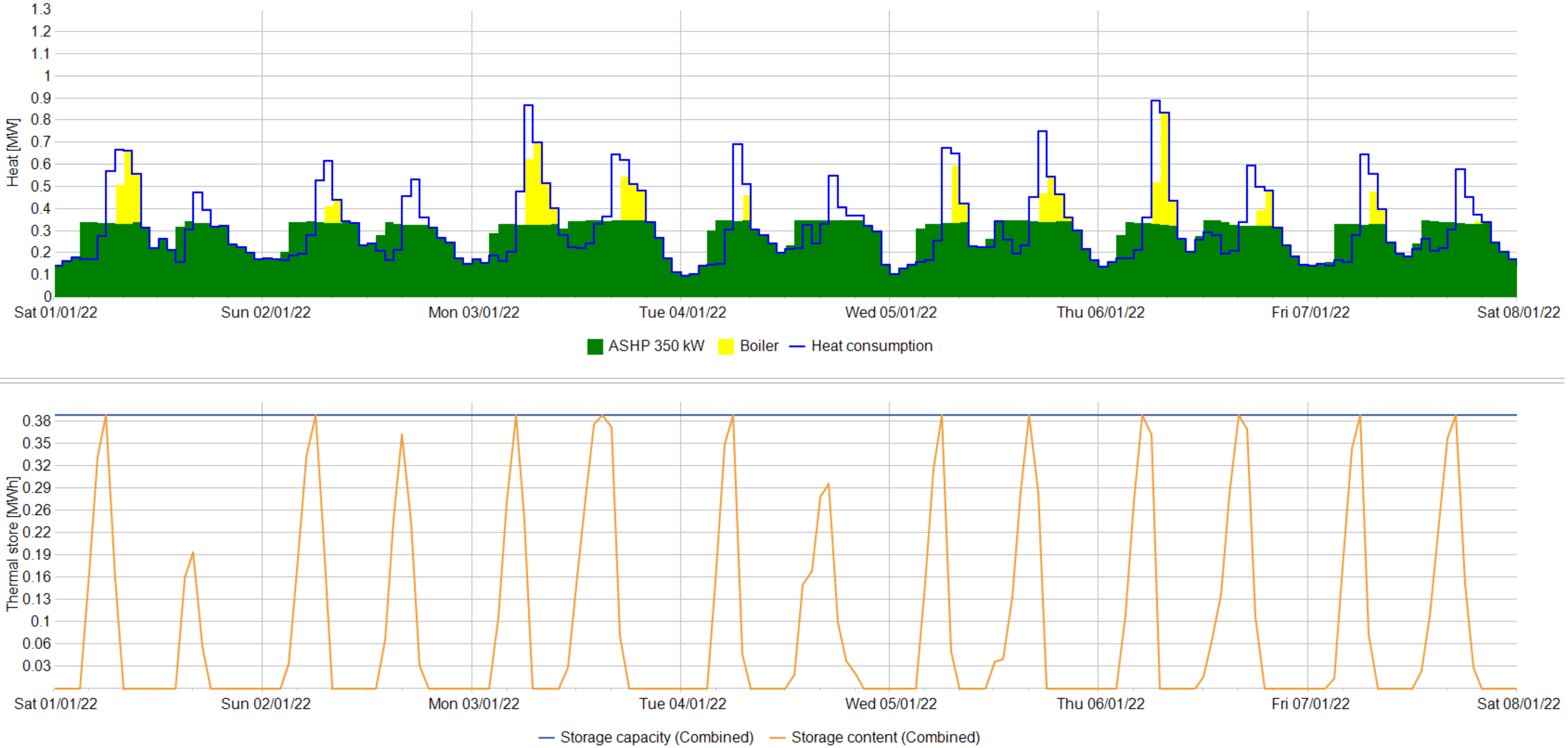


Figure 24 show a seven-day period in January. The light and dark green sections show the heat demand met by the main heat generator (in this figure it is the 350kW ASHP) with the back-up gas boiler providing peaking requirements. The 50 m^3 thermal store fully charges and discharges each day with a second additional variable charge/discharge each day. The heat provided from the thermal store makes up for any of the gaps (shown in white on the top chart) between the heat demand and what is provided from the low carbon heating technology and the gas boilers. The thermal store is required far less in the summer months.

6.5 YEAR 1 PERFORMANCE OF SELECTED SCENARIOS

Table 15 shows some selected outputs from our Energy Pro™ and in-house modelling that feeds through to our TEM. Note that the carbon calculations are based on emission factors outlined in Table 16 and are shown here for reference (the TEM calculates lifecycle carbon emissions based on varying carbon emission factors each year).

Table 15: Selected inputs and outputs from Energy Pro™ and in-house modelling tools

Description	Unit	BAU	Scenario 1 GSHP	Scenario 2 ASHP	Scenario 3 Biomass
Size of generator (note 1)	MW	N/A	0.35	0.35	0.35
Thermal Store Size (note 1)	m^3	N/A	50	50	50
HP Efficiency/ sCOP (note 2)	-	N/A	3.50	2.90	N/A
Biomass efficiency	%	N/A	N/A	N/A	75%
Gas Boiler Efficiency (note 3)	%	76%			
Heat Demand (normalised heat sales plus network heat losses, Table 7)	MWh	1,833 (1,269 +564)			
Heat Generation (modelled from Epro)	MWh	N/A	1660	1660	1665
HP Electrical Consumption	MWh	N/A	474	573	N/A
Biomass consumption	MWh	N/A	N/A	N/A	2444
Heat Generation from Boiler	MWh	1,833	149	149	145
Boiler Gas Consumption (note 4)	MWh	2,414	196	196	191
Carbon emissions from natural gas (year 1)	tCO_2	494.1	40.1	40.1	39.1
Carbon emissions from electricity (year 1)	tCO_2	0	140.5	169.7	0
Carbon emissions from biomass (year 1)	tCO_2	N/A	0	0	26.9
Total emissions from fuel	tCO_2	494.1	180.5	209.8	66.0
Carbon savings from BAU	tCO_2	-	313.6	284.4	428.2

Note 1:The generator and thermal store have been selected based on the performance modelling process using Energy Pro

Note 2: Estimated value for GSHP; calculated in EnergyPro for ASHP based on external weather profile. It is necessary to calculate the sCOP for the ASHP as the air temperature varies by large magnitudes over the course of a day and throughout the year – the ground temperature stays largely the same throughout the year leading to the assumption of a consistent sCOP of a GSHP system.

Note 3: Average figure used

Note 4: Some residual gas boiler consumption remains in all scenarios due to the back-up generator

6.6 ENVIRONMENTAL IMPACT

The annual carbon emissions of each scenario (including the BAU) have been assessed based on the input fuels required for each scenario. Note that there are multiple fuels in each scenario; BAU, ASHP & GSHP scenarios use electricity (for heat generation and to run the energy centre post-CHP removal) and natural gas (back-up/peak heating) and the biomass scenario uses biomass (pellets), electricity (to run energy centre post-CHP removal) and natural gas (back-up / peaking). Emissions factors for natural gas and electricity are based on supplementary guidance from the Irish Spending Code[44], the biomass carbon emission factor is based on BEIS Green book carbon emission factor, as there is no published biomass carbon emission factor. The green book carbon factor, although low, is higher than that which may be used under the Renewable Energy Directive (RED), which has a zero-biomass emission factor. Note the emission factor for biomass does not include other lifecycle emissions (felling/shipping/processing etc). The carbon factors used are shown in Table 16 .

Table 16: Year 1 carbon emission factors

Fuel	Carbon emission factor tCO_2 / kWh	Fixed or variable
Natural gas	0.2047	Fixed
Biomass	0.01053	Fixed
Electricity	0.2961	Variable – reducing with grid decarbonisation

From section 2 we know that:

- Heat network gas consumption (2021) 2,372 MWh
- Heat sales (2021) 1,235 MWh

As this is all currently met by natural gas, the emissions for the network are **486 tCO_2 / year** (see section 2.4). If we compare the network emissions against two non-centralised options, namely:

a) Each property with its own natural gas boiler with seasonal efficiency of 85%, or,
b) Each property with its own individual ASHP with conservative COP of 2.5

Then the potential carbon emissions for these would be:

a) 178 x Natural gas boilers 297 tCO_2
b) 178 x ASHPs 146 tCO_2

Thus, we can see that in terms of carbon emissions, in its current status the network is performing significantly poorer than individual systems; served either by natural gas or individual ASHP systems. There is implicit residual value in the existing heat network infrastructure; improving the network operation through improved HIU management will reduce the energy demands and carbon emissions (before any decarbonised heat generation is even considered).

[44] Public Spending Code – Supplementary Guidance (https://assets.gov.ie/45078/b7dbf515ad694c3e8b2c37f1094b7dca.pdf)

As an illustrative example, if the heat network had 20% heat losses on top of the heat sales, this could result in total gas consumption of 1,950 MWh (using a gas boiler efficiency of 76% used in the other calculations) and 399 tCO_2 / year – thus a saving of 86 tCO_2. Achieving heat losses of 20% on the network will require substantive on-going maintenance in particular in HIU operation to be achievable.

Other major environmental impacts are predominantly linked to the combustion of fuel (existing natural gas boilers or biomass boiler replacement) in existing (BAU) or replacement equipment and fuel supply for biomass.

Combusting biomass produces a number of emissions in particular particulates which can cause respiratory issues. Emissions from biomass combustion can be reduced and mitigated using flue abatement technology, but these cannot be removed completely and are often linked to poor combustion efficiency of burners when fuel quality is poor (high moisture content of woodchip can lead to incomplete combustion with the result often being dark smoke plumes). There are also life-cycle emissions from felling, producing and delivery of wood fuel that should be considered – locally produced, sustainable biomass products being the most environmentally friendly option, compared with imported biomass from overseas.

These are typically non-cashflow items but are included in our TEM, see section 7.7 for how these have been accounted for in our modelling.

7. TECHNO-ECONOMIC MODELLING

7.1 TECHNO ECONOMIC MODELLING OVERVIEW

The technical assessment and costing presented in the previous sections enables the development of a model for the three technology scenarios (ASHP, GSHP & biomass), as well as the BAU. This is undertaken via a techno-economic model (TEM). This model covers a 25-year period from 2023.

The TEM process draws in key parameters including cost (CAPEX, REPEX and OPEX), energy (utility) demands, maintenance and utility rates in a single model. Importantly the model includes timing of spend, which enables a cash flow analysis to be run for the selected time period. Social costs (cost of carbon and air pollution) have been included in the analysis, but for reference they are often shown in tandem with figures and outputs that do not include these factors.[45]. The boundary that outlines the data that is input into the TEM is shown in Figure 25.

This is a Techno-Economic Model and **not** a Financial Model, therefore items such as a balance sheet and profit and loss accounts, VAT, depreciation of assets and sunk costs are not included.

Key model inputs are all provided in Appendix 4; the excel version of the model accompanies this report and should be referred to for all more detailed requirements.

The main TEM outputs are based on cashflow over twenty-five years. To allow for a clearer comparison between generation options, each option is separately rebased in the model to a Year 1 start point; this provides an equivalent comparison of payback, lifecycle Net Present Value (NPV) and carbon abatement cost.

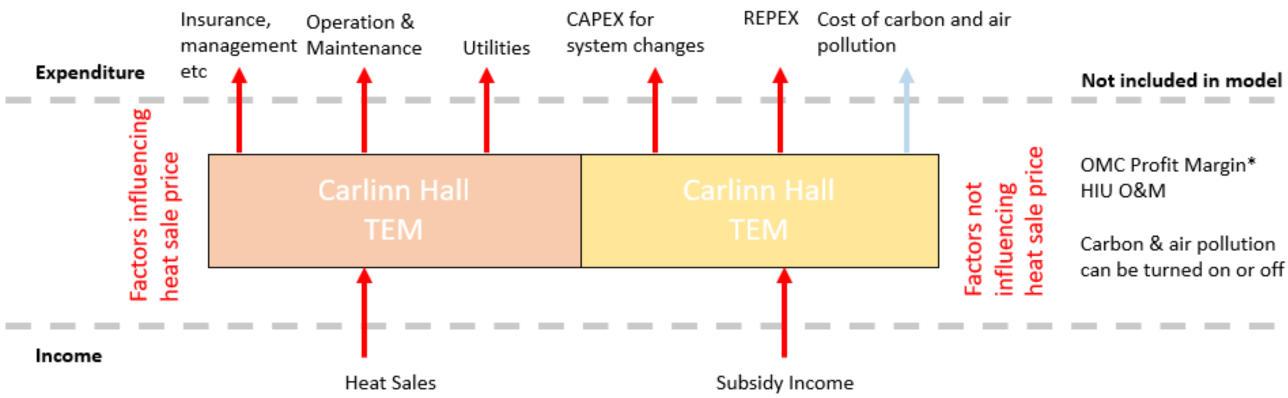
Lifecycle cost is essentially the discounted cashflow over the 25-year project; it is negative for all cases as it is the cost over time. Inspecting the relative cashflow compared to BAU provides a conventional NPV.

Definitions of the key modelling terms are provided below:

NPV	Net Present Value. The lifecycle costs of the scheme, converted to present day costs to account for the future value of money. Allows differing spend profiles over time to be evaluated against each other and show value of an investment compared to original cash injection.
Discounted Cashflow	The process of converting a cashflow over time to a present-day equivalent value
Discount Rate	The interest rate used to convert future cash flows into an equivalent present value
Carbon Abatement Cost	Capital cost invested per tonne of $CO2_e$ saved over lifetime of a measure

[45] https://igees.gov.ie/wp-content/uploads/2018/11/Valuing-Greenhouse-Gas-Emissions.pdf

Figure 25: TEM Boundaries. The image is split into two categories; those that affect the heat sale price (left) and those that do not affect the heat sale price (right). Social cost of carbon and air pollution are included in the TEM but can equally be turned off.



7.2 HEAT SALE PRICE

The price for heat sales has varied significantly with the volatility in the energy markets, and as heat is charged based on the heat demand on the network (monthly) and the cost of natural gas.

The heat sale price used in the TEM was calculated for each scenario such that the network operator is not making any profit from the sale of heat (the current way that heat is charged for), structured in Figure 26 and shown in Table 17. **The heat sale price is based on balancing the costs of operating and maintaining the network, with no profit for the OMC/network operator made by the sale of heat.** Note that by using these heat sale prices, the CAPEX & REPEX for the decarbonised solutions is not considered as part of the heat sale price. The overall day 1 heat sale price required such that in the 25-year model the overall cashflow is zero are shown in section 7.2.1.

Figure 26: Heat Sale Calculation in Model

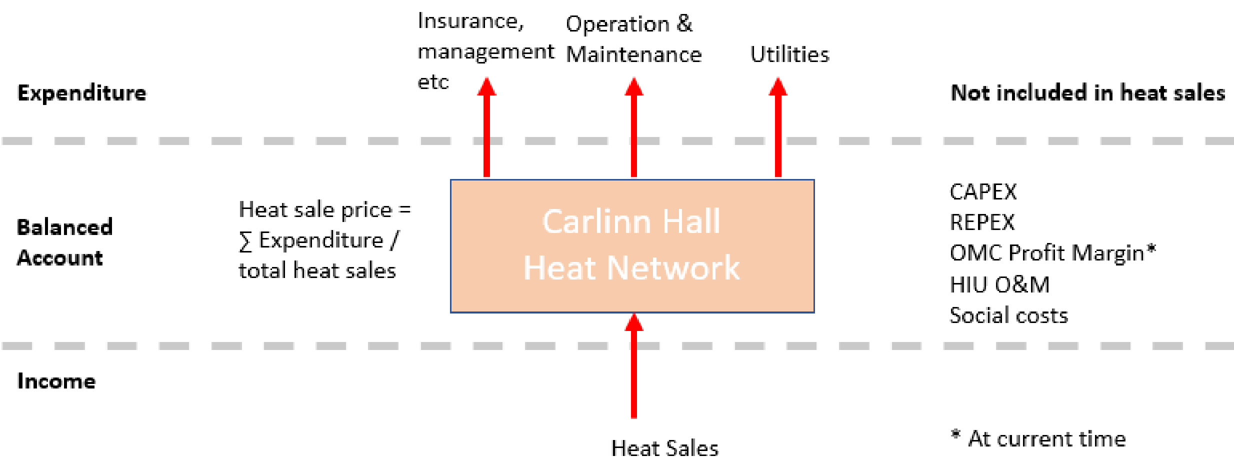


Table 17: Heat sale prices, without CAPEX or REPEX being factored in

Scenario	Heat sale price, Day 1 € / MWh
BAU (note 1)	220
Scenario 1, GSHP	164
Scenario 2, ASHP	187

Scenario	Heat sale price, Day 1 € / MWh
Scenario 3, biomass	327

Note 1: the BAU heat sale price was provided by the network O&M provider during the study (noting that it fluctuates frequently).The heat sale price for biomass has not been calculated to include potential income from the SSRH (i.e., heat sale price could be lower if income from the SSRH was included). The SSRH is designed to help support investments in renewables and those that are making such investments, i.e., the subsidy should assist those that are funding the CAPEX.

Table 17 shows that both the heat pump options represent solutions that **could result in a lower heat sale price than is currently offered to homeowners, based on the current pricing structure.** The biomass heat sale price needs to be 327 € / MWh so that the system does not operate at a loss. This is a high price for heat for residents – however when the project started in late 2022, the heat sale price at that stage was **420 € / MWh.**

The heat sale price is a variable that the OMC / network operator is in control of – and the tumultuous global energy prices have meant that the heat sale price has risen significantly in the last few years. The objectives of both decarbonising heating systems and keeping running costs low (in this case the heat sale price), or lower than is currently offered, is difficult to obtain.

7.2.1 Alternative heat sale pricing

7.2.1.1 Potential heat sale prices when REPEX is included

A sustainable business model should consider cashflows throughout the lifetime of the equipment. Table 18 shows the potential heat sale prices when REPEX is included into the calculation. The REPEX is calculated based on the lifetime of the equipment age and the time period set in the model. The heat sale prices that include REPEX use the lifetime of the equipment to determine the cost (i.e., as the ASHP would need replaced first in the model, we have used 15 years as the time period required to pay-off the REPEX). Note that the heat sale prices including REPEX in Table 18 are not those that are used in the TEM and analysis. These heat sale prices are not adjusted for any SSRH income.

Table 18: Potential heat sale price with REPEX included

Scenario	Equipment lifetime (years)	REPEX (25-year period) €k	Heat sale price, Day 1 € / MWh	Heat sale price, including REPEX € / MWh	% increase
BAU (gas boilers)	20	(221)	220	228	4%
Scenario 1, GSHP	20	(912)	164	201	23%
Scenario 2, ASHP	15	(810)	187	231	24%
Scenario 3, biomass	20	(636)	327	352	8%

Including the REPEX into the heat sale price leads to increases between 8-24% on the existing calculated heat sale price. The CAPEX required has not been included, see next section.

7.2.1.2 Potential heat sale prices when REPEX & CAPEX are included

The pricing structure of the heat network is flexible, and the network O&M provider can currently flex the heat sale price. Table 19 shows a variety of potential heat sale prices when including REPEX and CAPEX into the cost model (not currently included as per Figure 26). This table also shows the impact of including or removing social costs and the benefit that the subsidy income can have on the heat sale price (if this was not taken as income by the network O&M provider). The impact of the social costs increases the biomass tariff by the largest amount, due to the inclusion of air quality impact.

Table 19: Potential heat sale price with REPEX & CAPEX included

Scenario	Year 1 heat Sale price used in the study	Heat Sale price including REPEX & CAPEX			
	Excluding subsidy; Excluding social costs	Including subsidy Excluding social costs	Including subsidy; Including social costs	Excluding subsidy; Excluding social costs	Excluding subsidy; Including social costs
BAU	220	228 (note 1)	288	228 (note 1)	288
Scenario 1, GSHP	164	254	264	271	282
Scenario 2, ASHP	187	241	251	246	257
Scenario 3, biomass	327	373	1001	392	1022

Note 1: There are no subsidies for the BAU.

Note that i**ncluding** the subsidy in the analysis **reduces** the potential heat sale price (as this is additional income for the network operator). **Including** the social costs in the analysis **increases** the potential heat sale price (as this is an additional cost for the network operator)

As the subsidy available varies with the technology, the impact of removing or adding this into the potential heat sale mix calculation varies between the scenarios (i.e., the impact of removing from the ASHP scenario is not as profound as the subsidy on offer is considerably less).

Table 18 and Table 19 show that the impact of including either REPEX or REPEX and CAPEX would significantly impact the heat sale price that is likely to be offered to home-owners. In particular, if including CAPEX in the overall heat sale price – this pushes the potential cost to homeowners to much higher levels than are currently being paid.

7.3 UNIT COSTS

The unit costs used in the model are shown in Table 20. Unit costs have been derived from two sources; costs provided by the network operator (natural gas) and those calculated from an SEAI commercial/industrial fuel cost comparison[46]. The costs for biomass and electricity were inflated such that the current cost of gas was in—line with these (i.e., the unit cost paid for gas is 11c/kWh, whereas in the SEAI comparison it is 8.59c/kWh (i.e., 25% lower) – therefore the electricity and gas prices were increased by this same 25% factor for a fair comparison). All of the utility costs are index linked to a general inflation rate of 3%; an additional 0.25% increase over the general inflation rate for natural gas, this has been included as a method for costing future fossil fuels against low carbon fuels.

Table 20: Day One Utility costs

Fuel Prices, Day 1	€ / MWh
Nat. Gas[47]	110
Elec Tariff	303
Biomass (pellet)	144

[46] https://www.seai.ie/publications/Commercial-Fuel-Cost-Comparison.pdf

[47] The band for natural gas from the comparison page is I2 and for electricity it is IB

Note that the heat sale prices and utility (currently natural gas) costs are intrinsically linked. One of the key elements of this study was an assessment of alternative low-carbon fuel options due to the high natural gas prices that commercial entities pay and subsequently pass on to residents on a heat network. Therefore, using historic or averaged utility prices (i.e., in this case it would be a lower natural gas unit rate) was not deemed to be the most appropriate method of developing unit rates to use in this study.

Our understanding of how the heat sale price is generated, during periods of high utility price, was to remove any profit/overhead heat sale price. As a commercial entity, the network O&M operator did not divulge the exact nature of how heat sales are - or were - historically priced. The utility and heat sale prices used in the TEM can be manipulated to see what effect differing unit rates can have.

Whilst an alternative pricing strategy for heat sales would likely need to be used if different utility prices were developed. Where unit rates of gas were historically lower, the network O&M operator would have had a slightly different way to charge for heat such that some overhead/profit was being achieved. Note that this study required the natural gas price and heat sale price to be high to show the "real" unit rates faced by commercial entities and passed on to customers. Invariably, all network O&M providers will have slightly different methods for determining heat sale prices – and this information is crucial to each individual heat network that is assessed.

7.4 CAPEX & REPEX

Table 21 shows the assumed CAPEX rates used for each scenario developed is used in the TEM. Each line item is costed, and replacement time periods are provided, this represents the REPEX (replacement CAPEX). For example, the lifetime of a centralised GSHP is estimated at 20 years, meaning there is upfront CAPEX in year 1, and replacement CAPEX (REPEX) in year 20. For the ASHP we have assumed that it has a shorter lifecycle of 15 years.

Table 21: CAPEX rates and replacement periods used in the scenarios

Item	Cost (€) item	Item	Replacement period (years)
GSHP	1,100	€ / kW	20
ASHP	1,100	€ / kW	15
Biomass boiler	660	€ / kW	15
Thermal store	2,300	€ / m^3	50
EC Balance of plant	50	€ / kW	50
EC power & controls	70	€ / kW	50
Civils / fencing to hard standing for external plant	230	€ / m^2	50
Energy Centre (biomass only)	2,300	€ / m^2	50
Fuel store (biomass only)	1,320	€ / m^2	50
Power connections, substation, switchboard	€300,000 (note 1)		50
CHP removal	€10,000 (note 2)		50
Borehole array	63 €/m borehole (note 3); 220 boreholes suggested		50
Existing boilers	132,000 (note 4)		20
Controls	15,000 (note 5)		40
Replacement augers & screws (biomass only)	15,000 (note 6)		15

Note 1: Estimate based on current grid capacity at site.
Note 2: Estimated value (consistent across all scenarios)
Note 3: Based on information provided by Geological Survey Ireland. Note this cost includes design, prelims and allowances. We have added an extra 5% for multi-array design.

Note 4: Estimate based on €110/ kW
Note 5: Based on information provided by network O & M provider (no quotes provided to evidence)
Note 6: Estimated based on previous project experience. Note that augers and screws can fail frequently on biomass systems due to poor fuel quality (wet fuel can get clogged/cause excessive strain on machinery) and poor design (angled

As our TEM is designed to run for 25 years, items with a replacement period > 25 years have not been modelled to require replacement.

Refer to Appendix 3 for more detailed CAPEX sheets for all scenarios. All costs are to 2023 cost year, exclude VAT, and have the following allowances, presented to the SEAI team in December:

- Prelims & Profit 20%
- Design & Project Management 10%
- OH&P 12%
- Contingency 20%

Table 22: CAPEX summary

	BAU	Scenario 1 GSHP	Scenario 2 ASHP	Scenario 3 Biomass
CAPEX (€m)	0.02	3.63	1.44	1.14

Note that CAPEX from the BAU scenario arises from the BEMS upgrade that is expected to be undertaken in 2023 and the replacement boilers (assumed 2028 install) these are included in all scenarios.

7.5 OPERATION & MAINTENANCE COSTS

Currently the heat network and energy centre O&M costs provided by the network O&M provider are €11,160 / year. This has been kept consistent for the BAU and all future scenarios as in all cases the gas boilers have been kept for back-up and peak demand requirements, note we have removed the CHP units for the decarbonised scenarios.

The OPEX for each scenario is a combination of the O&M costs plus the fuel/utility costs.

Additional O&M costs based on the installed technologies have been added to each scenario, these are shown in Table 23.

Table 23: Operation & maintenance costs for different technologies. Costs are provided in Euro / MWh of heat generated, and based on previous project experience and assumptions

O&M Item	Cost	Unit
Central GSHP	8	€/MWh
Central ASHP	12	€/MWh
Biomass	15	€/MWh
Gas Boiler	5	€/MWh
Electric Boiler	5	€/MWh

Costs for maintaining the HIUs **have not** been added as a new O&M measure as it is assumed that the cost to maintain the HIU by the network operator would be negated by income from residents paying an annual fee (i.e., the cost to the network operator to do the annual maintenance would be paid by householders, as the HIUs are not being maintained by the network operator currently – this cost/income is assumed to be net-neutral).

There is a risk in this approach. While the HIUs should be maintained, it is possible that some are not. As a devolved responsibility to end customers, there is no direct data to support this either way, although the concerns over network performance at least indicate that there is a risk that some units are not maintained. Were this the case, ensuring adequate maintenance would in fact increase net cost to consumer, regardless of who undertakes this task.

The costs for this we would expect to be in the region of €90 per property / year (so approximately another ~€16,000 per year) that would be borne by the network operator. Again, there is uncertainty over the condition of the plant; there remains a risk that remedial works are required.

7.6 SUBSIDIES & GRANT FUNDING

For the scenarios developed, we have assumed that there will be some subsidised income/funding from the Support Scheme for Renewable Heat (SSRH). This has different mechanisms depending on the technology. Note that during the writing of this report, the SSRH was reviewed, and as such the tariffs/subsidies are based on the most up to date values (2023).

7.6.1 Biomass

Biomass support comes in the form of quarterly payments to participants, on a 15-year basis, based on the amount of renewable heat energy used for eligible purposes. This uses a tariff (c/kWh) which starts at 5.66 c/kWh for the first 300 MWh of eligible heat used, with 5 payment tiers on a reducing scale to 0.37 c/kWh for 10,000-50,000 MWh. This equates to ~ €45,000 per year or ~ €675,000 over the course of 15 years, based on the current tariffs.

7.6.2 Heat Pumps

Heat pumps are eligible for an installation grant up to a maximum proposed level of 40% of the installation cost.[48] The value of the grant varies depending on the temperature application (for this site it is in the " low temperature" category (i.e., <95 degC) and the sCOP; the higher the sCOP, the higher the heat pump grant available.

In the TEM we have assumed that the SSRH can be used in the design of the borehole array. We have excluded any allowances from the total CAPEX that is applicable to the SSRH grant. The SSRH can also be used for 7% of project management costs, which are included.

Our full CAPEX estimates are provided in Appendix 3; Table 24 shows the estimated SSRH grant value that either the GSHP or ASHP system could benefit from – these have been used in the TEM.

Table 24: SSRH heat pump estimated grant value

	GSHP	ASHP
TOTAL CAPEX (€)	3,630,987	1,441,800
CAPEX (€) (pre-allowance)	2,241,350	890,000
System sCOP	3.5	2.9
Grant % available (based on COP)	35%	25%
Grant available (€) (grant % * pre-allowance CAPEX)	784,473	222,500
Project management fees (7% of estimated PM CAPEX)	15,689	6,230
Total estimated grant value (€) (grant available + PM fees)	**800,162**	**228,730**
% of total CAPEX (not including allowances)	35.70%	25.70%
% of total CAPEX (including allowances)	22.04%	15.86%

[48] https://www.seai.ie/business-and-public-sector/business-grants-and-supports/support-scheme-renewable-heat

7.7 AIR POLLUTION AND COST OF CARBON SAVING

The TEM has the ability to include costs for air pollution and societal cost of carbon, and upon agreement with SEAI these have been included in the TEM. There are no published air quality damage costs for differing fuel types available, however there are valuations for the estimated damage of non-greenhouse gas pollutants published[49], and these have been translated into air pollution costs using data on combustion of fuels from the National Atmospheric Emissions Inventory (NAEI)[50] (note that although these factors are compiled by BEIS, they are translatable to the Irish context as they are based on combustion data (i.e., they are not locational)).

7.7.1 Air pollution

Estimated damage costs have been provided for the following pollutants, and translated then into c/kWh for our analysis

- PM2.5, for three location types
    - Rural, Suburban & Urban (note we have selected suburban for Carlinn Hall)
- NOx
- NMVOCs
- SOx

These factors result in the following air pollution costs that are included in Table 25, and are used in the TEM. The calculations that have been used to produce these factors are included in Appendix 8.

Table 25: air pollution costs per kWh for each fuel used in the TEM

Fuel	c/ kWh (2023 values)
Electricity	0.00 (note 1)
Natural gas	1.95
Biomass	24.11

Note1: Whilst the generation mix that produces grid electricity is not emission free – pollution from the electricity grid that supplies the site is not considered to be locally produced.

7.7.2 Societal cost of carbon

The societal cost of carbon is not typically used in the Irish Spending Code[51], however there are values presented that can be used which are based on the EU ETS (European Union Emission Trading Scheme) and are presented for ETS and Non-ETS sites. The TEM model has two options for including societal cost of carbon as per Table 26. The TEM has been set in this case to use the Non-ETS values in the calculations. Note that the social cost of carbon does not factor in security of energy supply.

Table 26: Societal cost of carbon, rates used in the TEM

Fuel	€/tCO_2e (2023 values)
ETS	27
Non-ETS	59

Note that both the air quality and societal cost of carbon factors are index linked.

[49] https://assets.gov.ie/19749/77936e6f1cb144d68c1553c3f9ddb197.pdf
[50] https://naei.beis.gov.uk/data/emission-factors
[51] https://igees.gov.ie/wp-content/uploads/2018/11/Valuing-Greenhouse-Gas-Emissions.pdf

8. OVERALL TEM SCENARIO RESULTS

8.1 SCENARIO COMPARISION

The modelling process was used to directly compare the ASHP, GSHP and biomass scenarios as decarbonisation options for the heat network. These scenarios are based on the existing heat network and the delta-T of the network, assuming the control upgrades that result in improved system efficiency have been undertaken.

The lifecycle NPV analysis is in favour of the ASHP system compared to the GSHP and biomass scenarios (Figure 27) – the cost of borehole drilling being a major cost-contributor to the overall system CAPEX of the GSHP. The higher sCOP of the GSHP compared to the ASHP results in lower electricity costs to run the heat pump systems, but the difference in performance is not great enough for GSHP to be the most attractive proposition from a pure economic perspective. As the ground conditions are unknown, the overall sCOP of the GSHP system may be higher than we have modelled, a sensitivity using a sCOP of 4.0 has been included in section 8.2. This could mean that more heat could be extracted from the ground than modelled, changing the size and ultimately the cost of the borehole array Note that the higher sCOP would result in a higher SSRH grant value that can be achieved, as per Table 24, page 66.

Note that air-pollution costs predominantly impact the biomass scenario and so if these were not included then the result for biomass is substantially different – we have modelled this as a sensitivity but included in the main narrative of this section. Without these non-cashflow items the NPV is tipped slightly to the biomass scenario. The impact of including societal cost of carbon impacts all modelled scenarios to roughly the same degree as the post-installation carbon emissions for all scenarios are similar (due to gas being used for back-up heating purposes).

8.1.1 Scenario summary, financial

Table 27 shows an overall summary of the financial performance of the three scenarios evaluated in the TEM.

Table 27: Financial summary of scenarios

Scenario	CAPEX & REPEX (note 1) (€M)	OPEX (note 1) (€M)	Max subsidy (note 2) (€M)	Heat Sale Price (€/MWh)	NPV (€M)	NPV w/o subsidy (€M)	NPV incl. social costs (€M)
BAU	0.02	(10.3)	0	220	(0.09)	(0.09)	(1.36)
GSHP	3.63	(8.3)	(0.80)	164	(3.07)	(3.81)	(3.32)
ASHP	1.44	(9.4)	(0.23)	187	(1.64)	(1.86)	(1.9)
Biomass	1.14	(16.6)	(0.89)	327	(1.35)	(1.83)	(12.21)

Note 1: Based on 25-year TEM

Note 2: Subsidy based on SSRH, see section 7.6

8.1.2 TEM scenario outputs, financial

Figure 27 shows the project NPV of the three modelled scenarios over a 25-year period. This figure shows the NPV both including and excluding social cost of carbon. In all scenarios, the NPV is negative. **The impact of the social costs of carbon are clearly visible when comparing the standard 25-year NPV against that which incorporates the social costs.**

Figure 27: 25-year NPV. This figure shows the NPV when including and excluding the social costs of carbon.

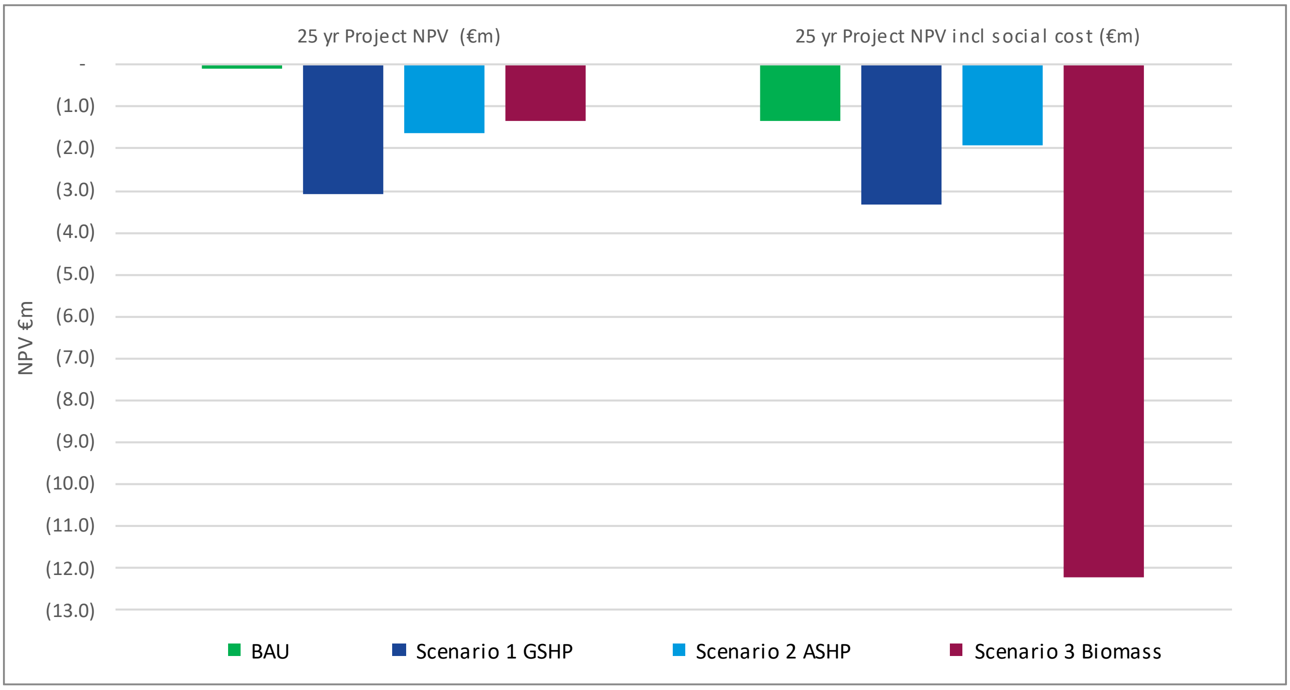
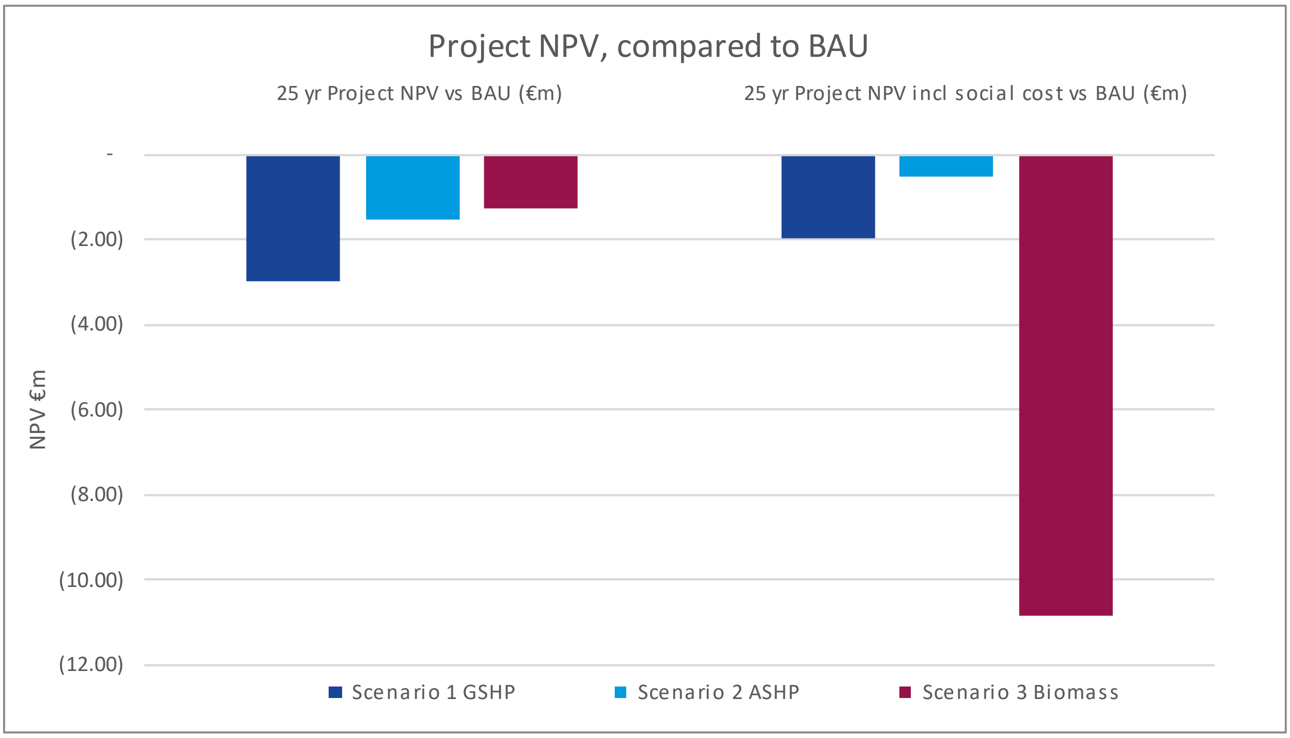


Figure 28 shows the 25-year NPV against the BAU. **Both of the heat pump scenarios have improved NPVs when the social costs are included, whereas biomass performs significantly poorer. The ASHP scenario performs the "best" overall in almost all categories (excluding the BAU).** The data from Figure 27 and Figure 28 is presented in Table 28.

Figure 28: 25-year NPV. This figure shows the NPV versus the BAU and shows this with and without social costs included.



The 25-year NPV analysis is shown in is Table 28. A positive NPV indicates that the projected earnings (cashflow) generated by the scenario (or project/investment)—discounted for their present value—exceed the anticipated costs. It is assumed that a scenario with a positive NPV will be profitable. An investment with a negative NPV will result in a net loss. We can see therefore, that all scenarios have negative values and don't represent traditional "investments". This is common across heat decarbonisation projects where both project costs (CAPEX, REPEX & OPEX) and utility prices (electricity or biomass) are more expensive than the counterfactual (natural gas boilers).

Table 28: Net present value of scenarios. This uses discounted lifecycle cashflows calculated for each year in the TEM to generate a 25-year NPV

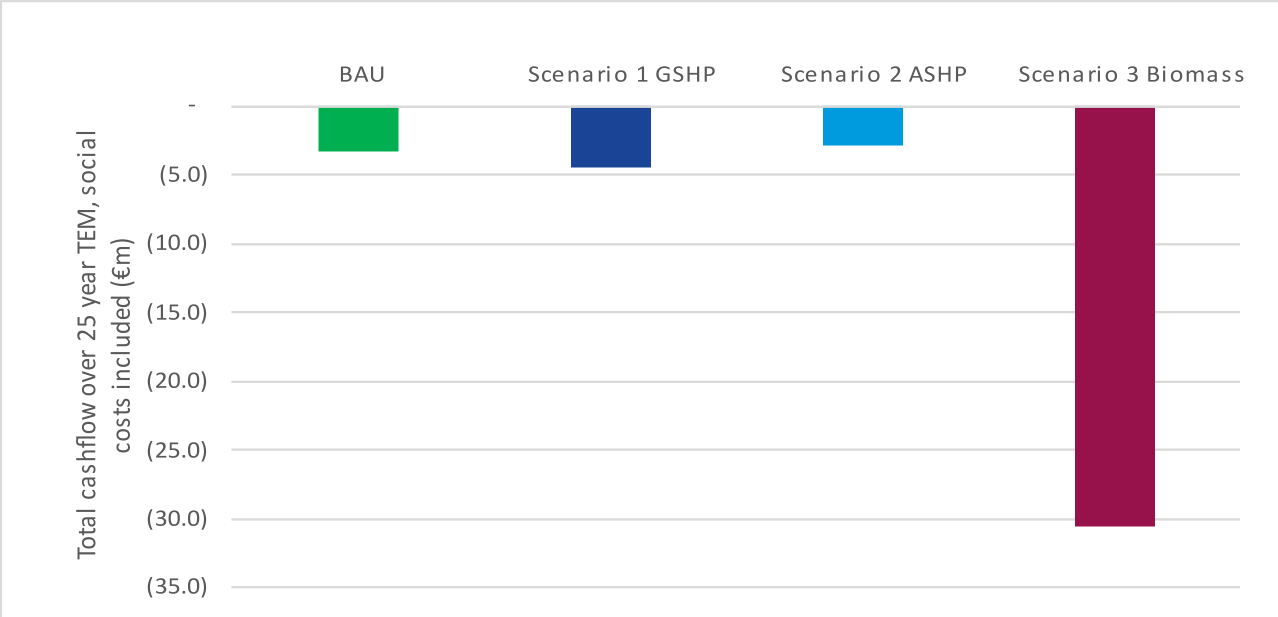
Net Present Value Measure	BAU	Scenario 1 GSHP	Scenario 2 ASHP	Scenario 3 Biomass
25 yr Project NPV (€m)	(0.09)	(3.07)	(1.64)	(1.35)
25 yr Project NPV vs BAU (€m)	-	(2.98)	(1.56)	(1.26)
25 yr Project NPV without grant (€m)	(0.09)	(3.81)	(1.86)	(1.35)
25 yr Project NPV without grant vs BAU (€m)	-	(3.54)	(1.74)	(1.09)
25 yr Project NPV incl. social cost (€m)	(1.36)	(3.32)	(1.90)	(12.21)
25 yr Project NPV incl. social cost vs BAU (€m)	-	(1.96)	(0.54)	(10.85)

Biomass has the "best" NPV when the social cost of carbon is not included in the analysis. This is due to the high heat sale price that has to be charged to offset the cost of fuel. This heat sale price (32.7c/kWh, Table 17) is higher than the homeowners currently pay in our BAU scenario[52] meaning that although favourable under these conditions from the perspective of the network O&M provider – the conditions would not be favourable for residents on the heat network, **and this high heat sale price does not meet the objectives of this study.**

The associated total cashflow (this includes all CAPEX, REPEX & OPEX and income from heat sales) over time for each scenario is provided in Figure 29 – this figure includes the social cost of carbon – hence the BAU has a negative cashflow.

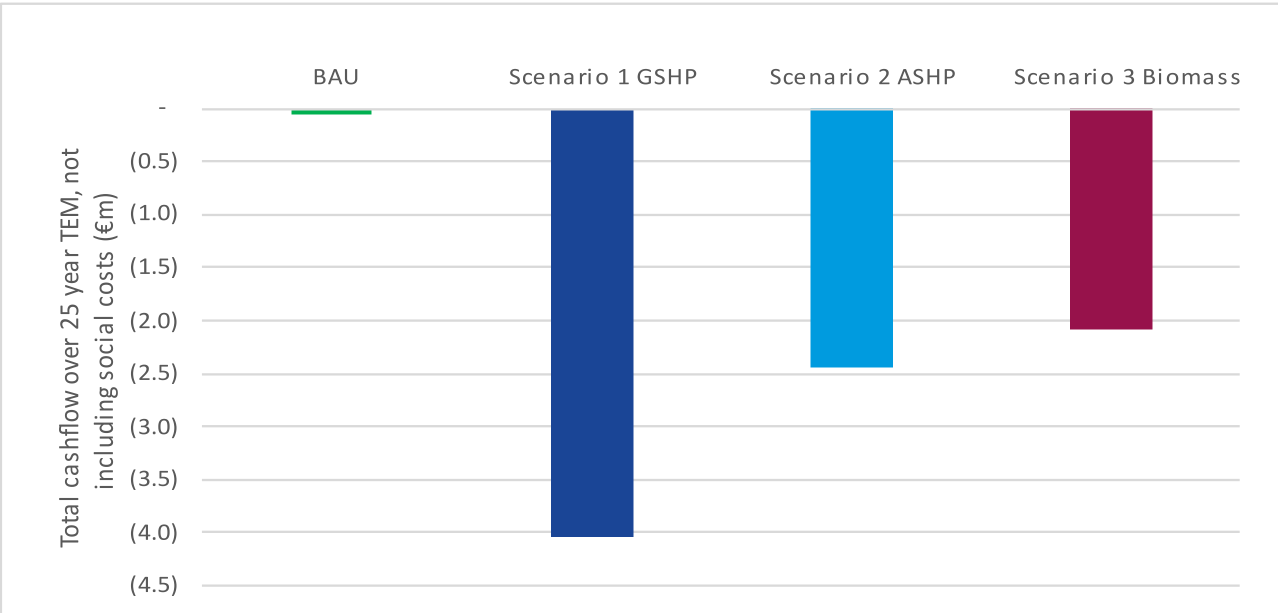
[52] As heat sale prices fluctuate based on the efficiency of the system, they change month to month. The heat sale price used in the BAU was based on discussions with the heat network operator but were as high as 42p/kWh when the project started in late 2022.

Figure 29: Total cashflow per scenario (CAPEX, REPEX & OPEX and heat sale income) over 25- year period – **including** social cost of carbon



Clearly, including the social costs of carbon and air pollution shows the cashflow of the biomass scenario to be very poorly performing. As these are non-cashflow items, Figure 30 shows the real-cashflow of the scenarios (note that BAU has very low cash-flow highlighting that the utility costs and heat sale prices largely even one another out over the course of the TEM timeframe).

Figure 30: Total cashflow per scenario (CAPEX, REPEX & OPEX and heat sale income) over 25- year period – **not including** social cost of carbon



The 25-year operational expenditure - for each scenario is shown in Table 29. Operational expenditure is calculated based on utility rates, existing network O&M, and new technology O&M rates. **This shows that over the course of the 25-year period analysed the GSHP has the best OPEX**. This is due to the superior sCOP that results in lower utility costs as well as lower generation O&M costs. Both the ASHP and the GSHP perform better than the BAU and biomass scenario (which is significantly the poorest performing).

Table 29: Operational expenditure, 25 years.

	BAU	Scenario 1 - GSHP	Scenario 2 - ASHP	Scenario 3 - Biomass
	(€m)	(€m)	(€m)	(€m)
Operational Expenditure (25 year)	(10.34)	(8.29)	(9.44)	(16.55)
Compared to BAU	-	2.05	0.9	(6.22)

Figure 31 shows the cumulative cashflow over the 25-year TEM period. These figures again include the social cost of carbon which are non-cash items.

Figure 31: Cumulative cashflow over 25-year period in TEM. Social costs of carbon are included in this figure.

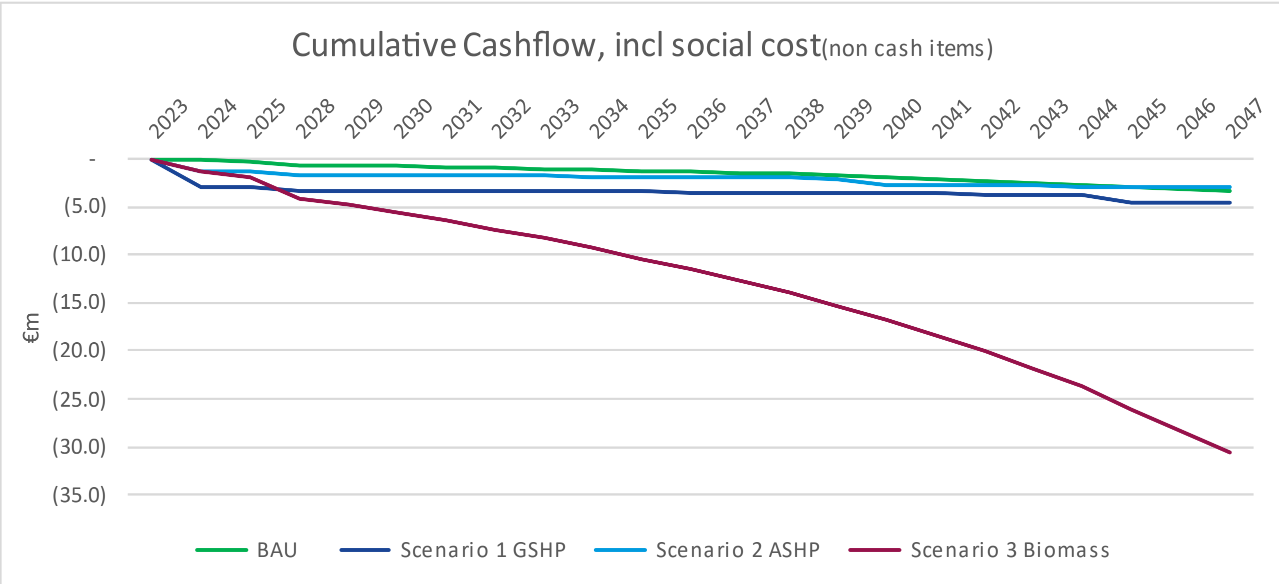
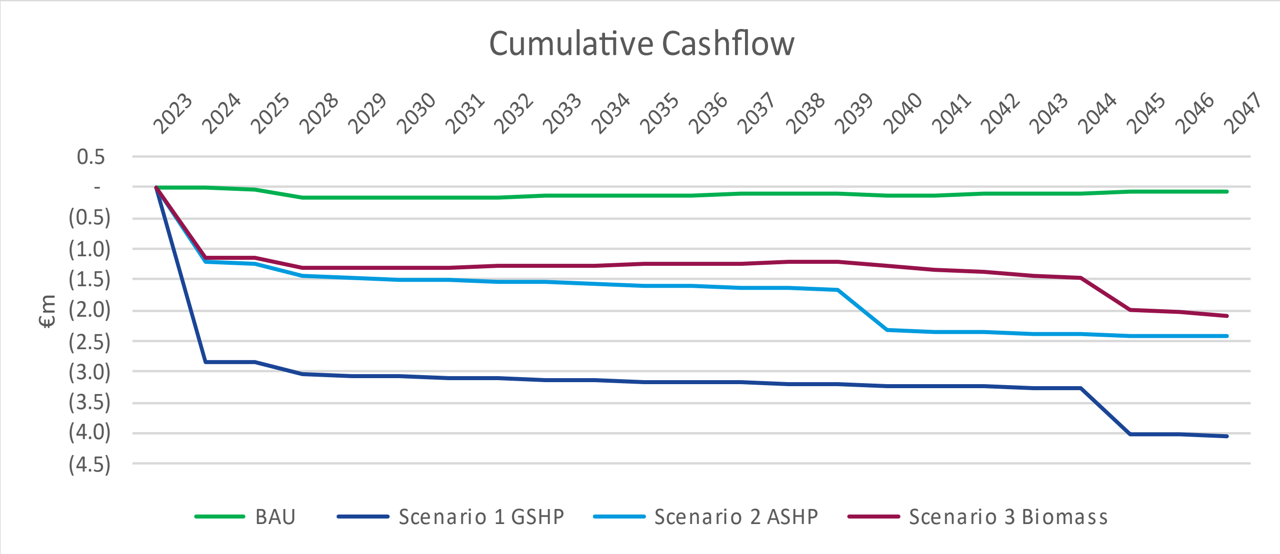


Figure 32 shows the cumulative cashflow without these social costs included. Note the difference in the scale compared to Figure 31 due to the cumulative negative cashflow.

Figure 32: Cumulative cashflow over 25- year TEM period. Social costs of carbon are not included in this figure. Heat sale prices used are those presented in Table 17



The trajectories and major CAPEX and REPEX can be seen in the cumulative cashflow totals (undiscounted), Figure 32. The cumulative cashflow for the BAU stays neutral due to the current charging mechanism for heat sales.

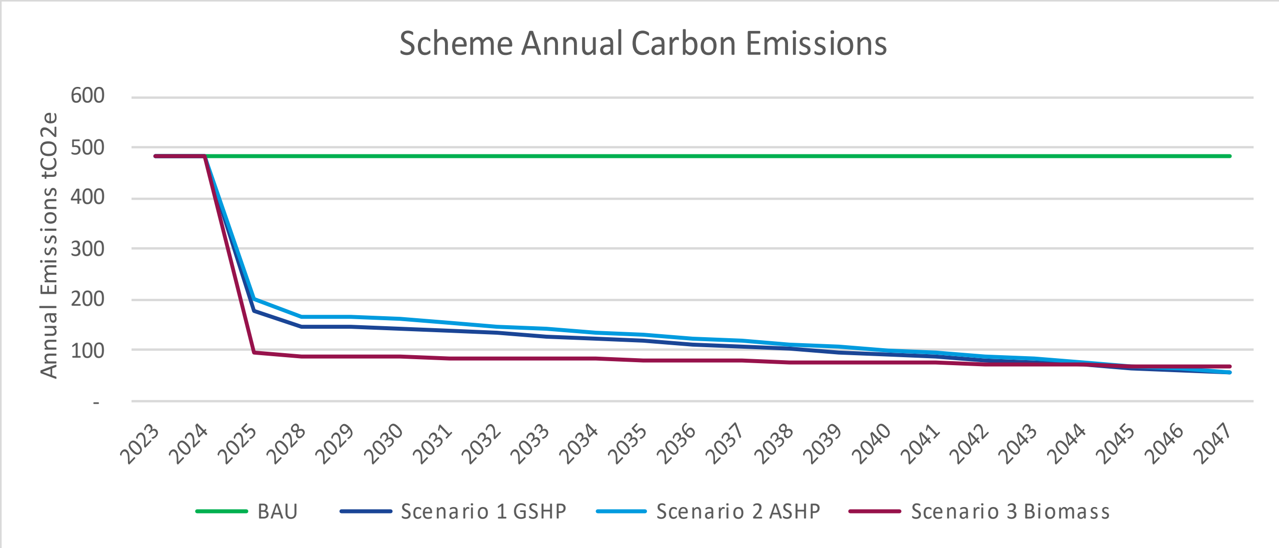
- Replacement boilers in BAU scenario implemented in 2028 – this is a moderately low cost estimated at €132k and so it is difficult to visualise on the figure due to scale
- Drop in cumulative cashflow in 2024 is the CAPEX of the scenarios
- Drop in 2039 & 2045 from the REPEX of major plant items (15-year replacement service for ASHP, 20 years for GSHP and biomass generators)

8.1.3 TEM scenario outputs, carbon

The associated carbon emissions trajectories are shown in Figure 33 and Table 30. Residual grid emissions are based on a marginal abatement cost curve methodology[53].

[53] Public Spending Code – Supplementary Guidance (https://assets.gov.ie/45078/b7dbf515ad694c3e8b2c37f1094b7dca.pdf)

Figure 33: Annual carbon emissions



There is an immediate, sharp reduction in carbon emissions due to the low carbon alternatives suggested in each scenario. The residual emissions for each scenario are due to low grid/biomass emission factors and the residual gas peaking plant that is retained. Note that the emissions reduce in all scenarios as the grid electricity factor decreases. Electricity is used for fuel into the heat pumps (scenarios 1 & 2) and to power the energy centre (all scenarios) after the CHP is removed (i.e., CHP retained in BAU and so scheme emissions remain steady in the BAU).

It is clear that decarbonising the Carlinn Hall heat network can achieve carbon emission reductions of ~80% (~284-428 tonnes CO_2 saving (based on year 1 emission factors) per year). This is equivalent to 190 - 285 new passenger cars/year[54]) compared to the BAU for any of the decarbonisation solutions. The residual emissions are due to gas-back-up plant being retained, this could be replaced with an electrode boiler to achieve further carbon emission reduction, this would impact lifecycle CAPEX and OPEX[55].

Table 30: Scheme carbon emissions

Scenario	Total emissions (25 yrs) (tCO2e)	Change in Emissions to BAU (25 yrs) (tCO2e)	Change in Emissions to BAU (25 yrs) (%)
BAU	12,139	-	-
Scenario 1 GSHP	3,557	(8,582)	(70.7)%
Scenario 2 ASHP	3,828	(8,310)	(68.5)%
Scenario 3 Biomass (pellets)	2,822	(9,317)	(76.8)%

The total carbon emissions are calculated each year based on the fuel mix (i.e., electricity (both heat pump scenarios), biomass and natural gas for peaking plant), system efficiency (combustion efficiency for natural gas and biomass), COP/sCOP for heat pumps) and annual emissions factors; note for natural gas and biomass we have a fixed carbon emission factor, whereas for electricity we have a variable factor due to on-going grid decarbonisation, see Table 16, page 57.

[54] Based on emissions of 120.1g/km for a new car and an average annual mileage of 12,200 km
[55] We would assume a cost of approximately €80 / kW for an electrode boiler

8.2 SENSITIVITY ANALYSIS

A number of sensitivities have been undertaken, predominantly using the TEM, and are presented below. Note that the soft copy TEM has been provided with this report, allowing the user to undertake their own sensitivity on parameters of particular interest.

8.2.1 With higher sCOP from GSHP

The TEM was run with a higher sCOP for the GSHP system, the results are shown in Table 31.

Table 31: Sensitivity: higher sCOP for GSHP scenario

Item	Original	Higher sCOP	Difference	% improvement
sCOP	3.5	4.0	0.5	14%
25 yr Project NPV (€m)	(4.82)	(4.55)	0.27	6%
Estimated borehole array requirement (metres)	33,000	35,400	(2,400)	(7%)
Borehole array CAPEX (€m)	1.36	1.45	(0.09)	(7%)
Network heat demand	1,832		N/A	N/A
Electricity consumed by heat pump (MWh)	474	415	59	10%
OPEX (25-year); (€m)	(8.29)	(7.65)	0.64	8%
Utility costs (part of OPEX, 25 year) (€m)	(7.61)	(6.99)	0.62	8%

Increasing the sCOP of the system means more heat is being extracted from the ground increases and a larger borehole array being required to satisfy that load (unless other factors reduce the overall heat load at the same time). We have estimated in the example above that an additional 16 boreholes are required. This could impact where the arrays are located and re-iterates that a full dynamic simulation of the potential system is required.

As the heat load delivered by the heat pump remains the same, the improved sCOP reduces the electricity consumed by the heat pump for that same load by ~10% which in turn reduces OPEX costs by 8%.

8.2.2 Without air pollution and cost of carbon

Our TEM allows for these “non-cash” costs to be included in the analysis, which have been included in the analysis following discussions with SEAI. A sensitivity analysis that has removed these non-cash items has been undertaken, the results from this are shown in Table 32 (note this information is also contained in Table 27 and Table 28). With the social costs of carbon omitted, the biomass scenario has the greatest NPV - as outlined this is due to the high heat sale price required to be set by the network O&M provider.

Table 32: NPV analysis for all scenarios with social costs removed from the cashflow

Net Present Value Measure – no societal costs included	BAU	Scenario 1 GSHP	Scenario 2 ASHP	Scenario 3 biomass
25 yr Project NPV (€m)	(0.09)	(3.07)	(1.64)	(1.35)
25 yr Project NPV vs BAU (€m)	-	(2.98)	(1.56)	(1.26)

8.2.3 Impact of HIU maintenance on heat price

We have assumed that HIU maintenance is a net-neutral cost on the overall heat network (i.e., we are assuming that this is currently paid by the homeowners, so to shift that onto the heat network operator is not incurring a whole new cost, it is just changing who pays for this service). However, we acknowledge the risk that this is not undertaken across all households and could be an additional cost to be borne by the network operator, and ultimately the end customer via an uplift in the heat sale price.

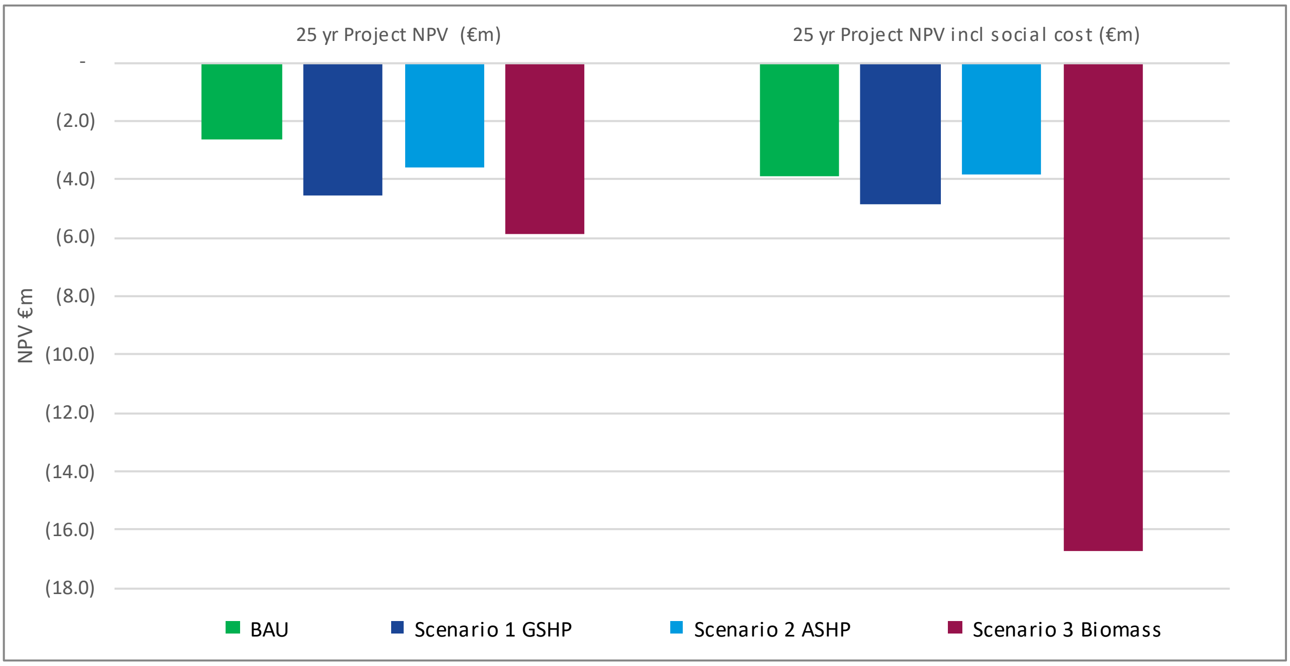
Assuming annual maintenance of the HIUs is €90 / year, and that there are 178 to maintain, this results in additional costs of €16,020 / year. Our annual heat sales are 1,269 MWh meaning that an uplift of 12.6 Euro / MWh would be required to maintain the same year-end financial status for the network operator. This uplift is not scenario dependent and would be applied to all scenarios.

8.2.4 Heat sale price

Our heat sale price varies in our scenarios, similar to the way in which heat is currently charged by the network operator. A sensitivity has been run that uses an assumed heat sale price similar to what a household may be paying if it was heated by a natural gas boiler. Using the SEAI domestic fuel comparison (January 2023)[56] and natural gas Band D2 (>5,556<55,556 kWh / year) rate of 8.47c/kWh and an average boiler efficiency of 85% this gives an equivalent heat sale price of €99.6 / MWh. This is considerably lower than the heat sale price currently paid (€220) and our required heat sale prices for each scenario provided in Table 17, page 60. All scenarios, including the BAU are negatively affected.

This shows that the shift to a centralised low-carbon heating source will be very hard to justify on a cost-perspective alone, when not considering any social cost element. Interestingly when, considering social costs, the NPV for the BAU, GSHP & ASHP scenarios are all relatively similar (though note they are all much poorer than when heat sale prices are derived to balance the income and expenditure. In all of these scenarios the network O&M provider would be operating at a considerable loss at this reduced heat sale price but existing utility price structure.

Figure 34: NPV for scenarios when using a fixed heat sale price of €99.6 / MWh



[56] https://www.seai.ie/publications/Domestic-Fuel-Cost-Comparison.pdf

8.2.5 Varying spark-spread / adjusting electricity costs

The utility prices for natural gas and electricity clearly have a significant impact on the financial analysis of the BAU and low-carbon heating scenarios.

We have run a number of sensitivities on varying difference between the electricity and natural gas price (often referred to the spark-spread). We have done this by fixing the natural gas unit price at €110/ MWh, and the heat sale price in each scenario but have varied the electricity utility price accordingly. Fixing the natural gas price means that in all cases the BAU remains the same.

Table 33: Sensitivity: Adjusting electricity prices, effect on NPV with fixed heat sale price

Sensitivity	New electricity price € / MWh	Electricity utility price divided by Natural gas utility price	Scenario 1 GSHP NPV, 25 years	Scenario 2 ASHP NPV, 25 years
Electricity utility price reduction, 10%	283.7	2.6	(2.90)	(1.45)
Electricity utility price reduction, 20%	264.4	2.4	(2.73)	(1.26)
Electricity utility price reduction, 30%	245.1	2.2	(2.57)	(1.06)
Electricity utility price increase, 10%	322.3	2.9	(3.23)	(1.84)
Electricity utility price increase, 20%	341.6	3.1	(3.40)	(2.03)
Electricity utility price increase, 30%	360.9	3.3	(3.57)	(2.23)

An alternative way to consider this, based on the way the heat charging is currently undertaken, would be to determine what heat sale price could be achieved with the new electricity utility prices as shown in Table 33. Noting that the TEM is set up such that the heat sales balance the other costs (Figure 26) – these heat sale prices result in similar NPVs[57] to the base model (Table 28). The benefit in this situation would be to the residents who would have lower heat sale prices - whereas in Table 33 – the reduced electricity price (and fixed heat sale price) would result in higher profit/overhead to the network operator.

Table 34: Adjusting electricity prices, effect on potential heat sale price with existing pricing structure (i.e., no profit taken by OMC)

Sensitivity	Scenario 1 - GSHP Potential heat sale price	Scenario 2 - ASHP Potential heat sale price
Electricity utility price reduction, 10%	142	161
Electricity utility price reduction, 20%	133	151
Electricity utility price reduction, 30%	124	140

There are clearly any number of configurations for the utility prices and heat sale costs that can be put into the TEM for analysis. What is clear from this particular analysis is that; a reducing electricity utility price (and thus reduced differential between electricity and gas prices) can result in lower heat sale prices to the residents,

[57] The NPVs are not exactly the same as the NPV analysis is indexed, meaning that 25-year cash-flow is inevitably different when different utility prices and heat sale costs are included in the model.

but these are still not in-line with domestic gas rates. Alternatively, of course, the reduced electricity prices can result in a system that has a better financial performance from the perspective of the network operator.

The change in spark gap needs to be relatively substantial in favour of reducing power prices (> 20% equivalent reduction) compared to gas to enable the electrified solutions to outperform the existing from an economic perspective.

9. RESULTS DISCUSSION

9.1 TECHNICAL RISKS

This section outlines the key technical risks for the existing and future decarbonised heat network.

Overall project risks

- Ongoing network performance issues.
    - The risk is that existing issues cannot be mitigated without substantially more investment. Detailed investigation is needed to establish required scope, combined with the HIU ownership issue noted below.
- Heat sale price.
    - Study did not get full breakdown of charging, so will not be perfectly aligned with the network O&M provider's actual costs.
        - TEM can be updated if the heat sale pricing strategy changes.
- SSRH not achieved.
    - Project should be justifiable without the need for public funding support.
- HIU ownership.
    - With the current user ownership / O&M model, operating network as designed is near impossible to achieve. Moving this liability over will have heat sale cost impact, for some users (i.e., those who are **not** currently maintaining the assets) there will be an additional cost.
        - Move HIU maintenance liability to O&M provider.
- Lack of more detailed demand data.
    - Decarbonisation solutions may be under-estimated and replacement equipment under-costed in modelling.
        - Ensure new BEMS has facility to record network flow and return temperatures (heat meters will need to be connected correctly).

ASHP specific

- Noise.
    - Location of external units may require acoustic mitigation factors that would need to be costed for appropriately.
        - Acoustic consultants may be required to run a dynamic model to evaluate noise impacts and correct mitigation measures.
- Suitably qualified personnel to properly maintain system (for GSHP too but maintenance requirements higher for ASHP).
    - Risk that this could add to O&M cost more than predicted depending on local supply chain.

GSHP specific

- Ground conditions are an approximation.
    - Potential for variation in end sCOP or installed cost.
        - Test borehole will allow for accurate quantification of heat supplied by borehole array.
- Land ownership (unknown).
    - Impact on the viability of areas chosen for potential borehole arrays.
- On-going maintenance.
    - Heat pump plus monitoring of boreholes – specialist requirement.

Biomass specific

- Planning – the following would form part of planning application, with requirements placed on the system by local planners.
    - New energy centre adjacent to existing - will require planning consent.

    - Noise impacts of both mechanical equipment installed and fuel delivery vehicles & equipment (delivery vehicles plus specialist equipment (i.e., blower deliveries).
    - Local air pollutants – minimum fuel quality (higher risk with poor quality fuel).
- Maintenance requirements.
    - Significantly higher than existing boilers or proposed air source or ground source heat pump systems.
- Availability of locally produced fuel.
    - Associated emissions of fuel higher than simulated.

9.2 RECOMMENDED TECHNOLOGY SOLUTION

The technology that is recommended as being the primary decarbonisation solution for the Carlinn Hall heat network is a **centralised air source heat pump**. A combination of the dynamic simulation and subsequent analysis in the techno-economic model outlined that this technology could be implemented at the site and would produce the most advantageous NPV for the network O&M provider. An ASHP solution **could** also result in lower heat sale prices compared to the BAU. The GSHP solution would result a system with a better overall sCOP than an ASHP – resulting in lower carbon emissions and utility/fuel costs for the network O&M provider The borehole array makes it a less financially attractive and higher capital project.

GSHPs on heat networks are a viable solution – this viability increases with aspects such as presence of cooling or a more varied heat demand profile – or where borehole arrays can be installed resulting in less disruption (i.e., during building phases of developments, or on adjacent land where drilling can be undertaken in a more efficient manner).

Biomass is not the recommended solution but arguably could be implemented and could operate at the current network system conditions without affecting the heat generation efficiency considerably.

9.3 CURRENT NETWORK CONSIDERATIONS

9.3.1 BAU

Our BAU model is used to compare scenarios against one another – however the commercial nature of this heat network means that, whilst there is social and political pressure on commercially owned heat network operators to ensure householders are not passed on commercial heat pricing, the heat network in its current status, whilst operating inefficiently in terms of heat delivery, is still delivering heat to all customers. If the price of gas was to drop to pre-2021 levels, then the price of heat to customers would also drop accordingly. From on-site discussions with the engineering manager of the network operator, we know that the OMC does not have vast amounts of revenue to invest in alternative, low-carbon alternatives – irrespective of grants, tariffs, or other financial mechanisms[58]. The contract between the OMC and the network O&M provider is governed by the MUD act[59] which limits the length of contract that can be entered into between the two parties. This inevitably creates conflict for long-term investment proposals for projects of this scale. Therefore, the BAU model is expected to be in-place for several years, at least until the boilers reach their end of life (from approx. 2028), unless there is external intervention.

9.3.2 Network operation

A key finding from this project was on the operation and maintenance of the HIUs on the network. Without intervention, more HIUs are likely to start performing poorly which will lead to further deterioration of the network.

[58] The OMC is regulated by the Multi-Unit developments (MUD) Act 2011 (https://www.citizensinformation.ie/en/housing/owning_a_home/home_owners/management_companies_for_apartment_blocks.html#lf7c65). The company may not enter into contracts with providers of goods and services which are to last for more than 3 years.

It is imperative that if a low-carbon heating solution is designed for this site, the first consideration should always be to ensure the network is operating as efficiently as possible.

The current operation strategy with householders having the responsibility for their own HIU should be reviewed with a view to the OMC taking control of the HIUs on the network via a one-off purchasing / adoption agreement (or similar). This could be a complex issue depending on how well received this is by homeowners.

This will allow the network to be better managed and improve the delta-T of the network to allow for future decarbonisation if this is progressed. If the network was operating at design temperatures i.e., with a 20 degC delta-T – the return temperature would be lower (60/40) then the heat losses from the return temperature would be lower (irrespective of the heat generation technology) Heat losses of approximately 69,000 kWh could be realised if the network operated at this output (reducing from 564 MWh to 495 MWh / year based on our hydraulic model). There would also be lower network pumping consumption as a result of this network modification.

These benefits relate to distribution and are irrespective of generation solution.

9.4 TECHNOLOGIES

9.4.1 Heat pumps

In order to operate a heat pump at its designed efficiency, a year-round delta-T is necessary and a lower operating temperature on the network is desirable. The model used in our analysis uses the existing operating temperature, with a slight uplift on the delta-T from controls upgrades. Ensuring a year-round delta-T should be a major focus for any decarbonised solution.

We have not modelled a significant drop in flow temperature for our base scenarios; in order to operate the network at a lower operating temperature the network would require substantial reconfiguration.

To consider this opportunity, we modelled an alternative scenario using the GSHP strategy whereby a lower mean network temperature on the existing network was used in our hydraulic model – the temperatures used were 55/45 degC. This in turn resulted in lower annual heat losses on the network and in turn an increase in heat pump efficiency was realised. Heat losses from the network pipework dropped by ~ 30% over the course of the year, due to the lower operating fluid temperatures, and this resulted in an assumed COP uplift from 3.5 to 3.7[60]. The effect of this meant that a GSHP could save approximately €23-24,000 per year in electrical input costs from the COP increase. To allow a heat pump to operate at these conditions, the internal heat emitter systems would need to be upgraded to allow for lower system flow temperatures – it was highlighted during the site visit that at least some of the properties have underfloor heating systems which suit heat pump systems – those with radiator emitters might need to have these emitters upgraded or oversized. Alternatives to the existing DHW system(s) would need to be in-place as the supply temperature would need to be boosted in some form to produce DHW for use in the properties.

Unfortunately, we were unable to visit any of the properties whilst on site in November 2022 and so space for additional DHW plant could not be easily determined. Assuming though that each property would need some form of emitter upgrade at a high-level estimate of ~ €1,500 and DHW upgrade of €1,000 this would result in household upgrades of ~ €445,000 (for 178 households) to allow for a lower network operating temperature.

A more detailed study of the heat network that incorporates identification of the heating systems across the various archetype properties on the network and assessment of HIU performance – with a view to improve engagement between residents and the network O&M provider. Data from the new BEMS system that is expected to be installed should be made available or logged in advance of any future survey.

Heat pumps (air and ground-source) will suffer operationally from poor network conditions if the return temperature on the network remains high and this could cause cycling of the compressor which could lead to increased maintenance requirements and ultimately component failure. They still offer a route to decarbonisation with the network flow temperatures (they would operate with better COP with lower

[60] Guidance and typical output graphs are shown in CIBSE TM51 – Ground Source Heat Pumps, which show the typical COP with varying heat output temperatures (available from https://www.cibse.org/knowledge-research/knowledge-portal/tm51-ground-source-heat-pumps)

temperatures) but the overall delta-T on the network would need managed and operated correctly before any decision on future heat pump technology could be made.

Significant network modifications would be required to allow for this lower mean temperature as the delta-T was reduced to 10 degC for this analysis. As designed for a delta-T of 20 degC this means that the existing pipework would be undersized for this reduced temperature differential (larger pipes would be required to deliver the same volume of heat). **This extensive network reconfiguration has not been included in our dynamic simulation or TEM modelling – but the costs of this upgrade based on our hydraulic model cost breakdown is in the region of €3.5 – 4 M.**

The main point of contention will arise when considering a heat pump solution to satisfy DHW demands on the existing network. We have assumed that there is no DHW storage within the properties (from on-site discussions) meaning that the risk of legionnaires disease is reduced. The temperature out of a hot water tap will be no hotter than ~50 degC to reduce the risk of scalding – however water should not be stored at this temperature. Consideration for DHW systems would need to be made at the design stage of any solution to mitigate against storage risks. When assessed, the network was operating at flow temperatures of ~58 degC, which a heat pump system could meet at close to design COP.[61]

9.4.1.1 Air vs ground source system

<u>GSHP</u>

There are advantages for both types of system; **a ground-based system will consume less electricity due to the higher sCOP, produce more consistent temperatures that will lead to improved overall reliability**. A ground-based system is significantly quieter than an air-based system, as there is no requirement for large fans to pass air over the condensers and evaporators.

The assumed rates for on-going and **annual maintenance of the GSHP are also lower than the ASHP solution** (note that both are considerably lower than biomass).

The drawbacks for the GSHP system are clearly the **significantly higher upfront CAPEX and uncertainty over ground conditions for achieving the heating requirements of the network.**

<u>Potential ground related complexity in a GSHP system</u>

Drilling a multi-borehole array (~ 220 boreholes at 150m depth) in a relatively new housing estate could cause significant disruption to homeowners, in relation to noise, time to complete, ground uncertainty and array configuration. Whilst we assume that there is physically enough space to install a borehole array that can satisfy the network loads, implementing may be challenging. The area is not a single contiguous area which could complicate the design and installation works and would likely result in increased costs compared to a similar ground array on a single location.

The duration and disruption of borehole drilling works would need considering. Given the number of boreholes is likely to be in the order of 220 boreholes, with 400 being required in some configurations, the duration of drilling works is worth considering[62].

This represents many months of works which are unavoidably noisy and disruptive. Close engagement with the residents is likely to be required to ensure they are aware in advance, however it may be difficult to mitigate the noise and disruption in a way which residents find acceptable, given the areas are in close proximity to housing. Drilling would need to be planned accordingly between typical working days - 09:00-17:00, Monday – Friday to accommodate due to the location.

Land can revert to original use but access to well-heads is preferred in case of operating problems or damage at a later date (e.g., works on other services that later damages pipework) – thus unless absolutely necessary the area beneath the carpark should be considered the least suitable location of those highlighted for a borehole array.

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[61] Note the limit to the temperature that a heat pump can achieve is governed by thermodynamics but ultimately a heat pump can produce temperatures > 60degC, but this will start to produce poorer unit COPs and so it is advisable to reduce the frequency to which a heat pump system has to produce these high temperatures.

[62] Borehole drilling estimated at approximately 1 borehole/day (depending on depth)

A GSHP can offer lower heat sale prices – however integrating into an existing network – in particular the design and install of any borehole heat exchange system requires substantial space & planning. The ideal time to invest and investigate ground-based systems is when buildings/networks are being designed, to minimise the disruption of constructing the ground-source system. Whilst not impossible to implement at Carlinn Hall, it is perhaps unfeasible to assume that all available space identified could be used for a borehole array – noting that one of the spaces we identified (Area C, Figure 20) is underneath a car park – drilling boreholes in this area would clearly be undesirable and would require significant levels of cooperation and patience from homeowners. Sufficient space should be available in areas A, B & D which would avoid the requirement to drill in the car park.

It is unclear who owns the land within the estate which could add further level of potential complexity if a ground-based system was progressed.

<u>ASHP</u>

An air source heat pump system would be able to be integrated into the existing network over a much shorter period i.e., no source design, test or install is required). Our overall assessment is that an air-source heat pump option is the most likely decarbonisation solution at this location due a number of reasons:

- Low CAPEX.
- Lower-disruption/installation requirements (relative to a GSHP or biomass system).
- Reduced land ownership hurdles compared to the ground array.
- Lower overall project risk due to reduced ground risk.

These advantages are relatively marginal in the context of the size of capital budget needed. Should it prove easier to raise capital funding for a ground source, this may outweigh some of these advantages.

Noise considerations are a major consideration if a centralised ASHP system was to be installed – this can be mitigated with an acoustic enclosure, however the external components of the system would be 20-35m from the nearest house (depending on which side of the existing energy centre (Figure 17, page 38) the components were sited. Noise outputs from an ASHP will vary depending on capacity (number of compressors and fans) and whether the model is a low-noise variant – sound power levels are typically up to around 90 -100 dB for units 50-200 kW.

<u>Heat pumps versus biomass</u>

Both heat pump solutions enjoy the following advantages over biomass:

- No local air-pollution (compared to biomass).
- Relatively low-footprint (would need some space from surrounding area for equipment (less than the biomass solution).

9.4.2 Biomass

Although a biomass system can be eligible for ~ €45,000 income / year from the SSRH – it has the highest operational costs from high fuel and maintenance costs. Biomass requires significant maintenance to ensure the system operates successfully without long down periods or at lower than design efficiency. Fuel handling and transportation of fuel to the site is also a key consideration, which would need fuel deliveries to be made into the housing estate, which would likely be time constrained for 09:00-17:00 Monday – Friday. It is expected that weekly deliveries would be required in winter. Biomass has the benefit over a heat pump system that it can produce higher temperatures without having a significant knock-on impact on to the efficiency of the system, and the poor network performance would not negatively affect the biomass operation in the same way that it would a heat pump system.

Biomass systems also produce localised air pollutants (particulates, nitrous oxides (NOXs), sulphur oxides (SOXs) and other volatile organic compounds (VOCs)) that will require significant flue-abatement technology to minimise the impact of emitting these (these cannot be removed entirely as a product of combustion). Given that biomass was reputably (but never evidenced) installed at the site and removed, then the barriers to this achieving the desired project outcomes could be significant. Smoke from un-combusted fuel contains higher levels of pollutants and smoke levels often increase with poorer quality (higher moisture content) fuels.

Biomass has not been the technology recommended in this report; however, it remains an implementable solution – in particular if cheap/local wood fuel could be used at the site which would result in low utility and thus low heat sale prices being possible – this does not appear to be possible with existing fuel prices.

10. CONCLUSIONS AND STRATEGY

10.1 COMMERCIAL CONSIDERATIONS

10.1.1 Ownership model

Currently the heat network is owned by the OMC and managed and maintained by the network operator. The HIUs, as previously outlined, are the responsibility of the homeowner to maintain. It is clear from the heat meter data shared during the project, that this model has led to poorly performing HIUs which has a big knock-on effect on the overall network performance.

In terms of ownership model for any decarbonised heating solution, it is expected that an Energy Supply Company (ESCO) is the most likely way to fund and manage the new heating solution, not unlike the current set-up, with homeowners/customers paying for heat delivered to their property, and the ESCO having operation and maintenance responsibility for the heat generation source, heat network, HIUs and overall responsibility for continuity of heat supply.

10.1.2 Integration into wider Dundalk Strategy

A decarbonised heat network, operating at the existing system temperatures could, in theory, be a suitable candidate for connecting into a larger district heating scheme in the future, if suitable tie in-points were created. This assumes that any future larger district heating scheme operated at similar temperatures (i.e., was not designed for low temperature applications such as new-build housing).

This would have knock-on implications for the balance of the network and, perhaps more importantly, the ownership, operation & management of the Carlin Hall network. Integrating the Carlinn Hall heat network into a larger system would require some form of ownership transfer/renegotiation which could in-turn be beneficial to the overall network performance if this led to increased monitoring and performance reviews of the existing network.

As Dundalk has been designated a decarbonising zone by Louth County Council, this is expected to accelerate decarbonisation studies and optioneering throughout the town of Dundalk. Whilst there are no current plans to design and install a large heat network, we know that this was an option that had been investigated in the "Dundalk 2020"[63] programme. The neighbouring Crowne Plaza hotel installed district heating pipework underneath the carpark when constructed to allow for future integration with a wider heat network.

10.1.3 Procurement and Funding Options

As the heat network is privately owned and managed, procuring and paying for any heat decarbonisation solutions would not be met with public sector procurement rules.

If the SEAI or any other publicly funded Irish company was to use this system as a case study for future decarbonisation, then standard procurement rules would need to be followed.

As outlined in section 7.6, we have included funding from the SSRH in both the biomass and the heat pump scenarios. Note that our TEM allows for comparisons between options that remove existing grant funding or allow for variations in SSRH tariff structure to be undertaken which would produce different outputs if modified.

[63] https://www.askaboutireland.ie/enfo/sustainable-living/sustainable-living/casestudies/

10.2 STRATEGY

10.2.1 All heat networks

Whilst the scope of this study is to look at decarbonising existing heat networks, there are clearly some lessons learned during the project. All these topics are addressed in detail in CIBSE Code of Practice CP1, and networks that are developed in line with this guidance should be able to avoid some of these issues.

1. This network suffers from inappropriately high heat losses due to low load density. This contributes to excessively high heat sale prices.
    a. Investigating heat density and network losses at early stages, using method such as linear heat density followed by full calculation of pipe heat losses. This may show that a network is not appropriate for an area or would only be feasible operating at much lower temperatures and higher levels of insulation.
    b. A robust techno-economic model is required at feasibility stage, and a financial model at business case stage, to ensure that the network is financially sound. This should have clear illustration of how heat price is calculated, and how it is indexed in the future.
2. This network does not meet its design delta-T, and the ownership model of the HIUs prevents this from being easily addressed.
    a. The business case should not have been signed-off without clear ownership model that supported the long-term O&M approach.
3. Heat network customers do not enjoy the consumer protection other regulated utilities do. Once the network is in operation, there is limited oversight and ability to enforce adequate operation.
    a. Approach to consumer protection standards for Ireland to be considered, building on the experience of other countries with varying models of heat network ownership.
    b. Heat network licensing could be considered, ensuring minimum standards via the mechanism of ongoing state regulation.

10.2.2 Carlinn Hall heat network Short-term – efficiency first

The key objective of this study was to look at decarbonised heating solutions for communal heating systems in Ireland, using Carlinn Hall as the case study location, whilst keeping the heat sale price lower than has been faced in recent years. These two aspects do not typically go hand-in-hand which is why the discounted lifecycle costs for all solutions are negative.

The heat sale price is flexible and is controlled monthly by the OMC/network operator. The heat sale price was based on balancing the network operating costs. It shows that, if we remove CAPEX from the equation, both heat pump options offer solutions that result in heat sale prices that are lower than the existing network operation, but biomass requires a higher heat sale price.

Therefore, although the biomass solution offered good NPV (when social costs are removed) and a viable decarbonised heat source, it would not meet the objective of reducing household costs for heat.

Of the heat pump solutions assessed, an air-based system performs slightly better in terms of lifecycle costs than a ground system and has significantly reduced risk and installation requirements, and so is our chosen decarbonisation solution. See section 9.1 for outline on project risks and mitigation.

A key element that needs to be addressed is in the upkeep and maintenance of the HIUs. Having this centrally undertaken would allow for more in-depth heat networking trouble-shooting and operational maintenance to be undertaken to increase the delta-T on the network. Improving the overall efficiency of the network should in turn result in a system that operates closer to design conditions, and this should lead to reduced losses on the network – in turn reducing the heat sale price. **This could in turn improve the operating COP of a heat pump solution installed to produce heat.**

The existing model of maintenance means that the heat network operator does not typically gain access into a house on the network (heat meter readings are taken via radio networking). Having the HIUs under the guise and operation of the heat network operator therefore will not be as simple as “purchasing” the HIU or purchasing the operation and maintenance contract for each HIU as the homeowner may simply refuse. Therefore, a strategy to take control of the HIUs across a longer period is likely to be required. Clearly all homeowners would benefit if the network operated efficiently as the heat sale price could be kept lower especially in the summer when there is lower demand.

We recommend that the overall operation and maintenance of the HIUs is undertaken by the heat network operator – irrespective of whether or not a future heat decarbonised solution is installed – but this clearly has implications on the heat network operator, their staffing and experience.

10.2.3 Medium-Long term

While the primary scenario to be assessed in this study was a shallow geothermal ground sourced system, we do not recommend a ground-based system as the main decarbonisation solution for Carlinn Hall as outlined in Sections 8 and 9.

The heat network at Carlinn Hall (and any other fossil fuelled heat networks in Ireland) will need to be decarbonised so that Ireland can meet the 2050 net-zero commitment. In our scenarios we have assumed that construction (all scenarios) would be completed by the end of 2024. We have assumed that the existing boilers would be replaced (and retained for back-up/peaking) in 2028. When the boilers are due for replacement - this would be an ideal time to install a decarbonised solution on the network if nothing has progressed in 2023-24. If these boilers are replaced on a like- for- like basis, without planning or considering for a future heat decarbonised solution, then this will be a missed opportunity to decarbonise this heat network.

Clearly the price of fuels will need to be taken into consideration – some form of taxation on fossil fuels is likely to be one of the major mechanisms for initiating shifts to decarbonised alternatives and so although currently volatile – we expect that the cost of natural gas will continue to increase overtime (we have conservatively allowed for this increase as a 0.25% uplift over existing indexing). As this happens, all alternatives that are not taxed this way will become increasingly attractive alternatives– it is expected, that there will become a point whereby a heat pump solution will be both the most attractive decarbonised heat solution in terms of carbon emissions but also in terms of cost of delivered heat[64]. Currently the price of electricity versus gas is close to being at this point. In the unit rates used in this report, electricity was 2.8 times more expensive than natural gas – when this multiplier drops to around 2 - 2.4 then heat pumps can be the most cost-effective option compared to natural gas, based on utility prices only (i.e., not factoring in the CAPEX required to install a HP system).

10.2.4 Overarching strategy

Primarily, the existing network must be maintained and optimised so that it can achieve the design conditions – this will take considerable input from the existing network O&M provider – and the limitations on the boundary where they are able to enforce changes or undertake maintenance is currently a real barrier. If these barriers to improved network maintenance and optimisation can't be realised, then a decarbonised solution that used heat pump technologies would be a high capital investment with significant risk. The risk is slightly diminished for a biomass-based solution as the performance heat generation would not be as adversely affected by the existing network conditions compared to heat pumps, but this was not the technology that has been recommended in this report.

Furthermore, in depth site visits and analysis of the network – with a focus on HIU maintenance and HIU performance is a pre-requisite. Bearing in mind that there are 178 properties on the network and access issues remain, the process of a) assessing HIU performance and b) implementing HIU modifications and monitoring the results will be time and resource intensive – but must be undertaken to result in a heat network where a decarbonised heating solution is a viable project for either the network operator or a third party.

The overarching strategy for the site is:

<u>SHORT TERM - Efficiency first</u>

- Install BEMS upgrades, monitor and adjust network and generation performance.

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[64] The unit costs of electricity and natural gas used in this report are close to this point. In the unit rates used in this report, electricity was 2.8 times more expensive than natural gas – when this multiplier drops to below ~2.4 then heat pumps will automatically be the most cost-effective option compared to natural gas. This ultimately depends on the performance (efficiency) of the existing fossil fuel boiler and that of a heat pump (sCOP).

    - Connect energy-centre heat meters into the BEMS (where possible) and record the network performance.
- Isolate and remove the CHP unit, which is not operational, continue to run site on single engine.
- OMC/network operator to run monthly performance checks on HIU performance when taking meter readings.
    - We know this data is available, but it requires analysis to lead through to performance improvements.
- Use meter reads to plan for increased HIU monitoring and performance adjustments.
    - This should be communicated to all homeowners on the heat network – clearly it is to improve the network performance and not specifically linked to individual households. Homeowners could be asked to provide their latest maintenance report for the HIU, and the OMC/network operator could offer to do this (either pro-bono or for a fixed maintenance fee) if no maintenance records could be provided.
- Monitor performance of network regularly, aim to improve network delta-T performance, reduce system flow temperatures where possible.
    - DHW considerations and systems are a primary factor – we know that the network O&M provider previously trialled reducing network temperatures and this caused some issues for DHW provision for some residents.

<u>MEDIUM TERM - Planning to decarbonise</u>

- Ensure any future updates to the SSRH are recorded and integrated into the TEM supplied with this report (note that this was updated in early 2023 and this update is incorporated into this report).
- Use any information available from the Dundalk Institute of Technology (DIT) when their test-borehole is constructed to verify the ground-conditions in the local area – it should be possible to more closely ascertain the figures used in Section 5 – this can be used to rule out ground-based systems entirely if not favourable (if not favourable, more boreholes would be needed to meet the heating demands). Alternatively, a test-borehole could be drilled and a TRT could be undertaken at Carlinn Hall to verify ground conditions.
- If not already ruled out through social or heat sale price reasons, determine if air quality concerns would rule out a biomass fuelled solution.
- Ensure wider-Dundalk heat strategies (i.e., design of any future heat networks in the local area) are assessed and incorporated.

<u>LONGER TERM - Low carbon alternative</u>

- Discuss options for decarbonisation via air-source heat pump with suitable installers and designers.
- Initiate a design and build contract with chosen installers.
    - Ensure system can be future-proofed – install tie in connections or ports/valves that could be used to integrate into wider district heating system if designed.
    - A new low voltage sub-station will need to be installed and so this will require consultation with ESB networks (this is a requirement for either heat pump option), and it is included as a separate CAPEX line-item, to be funded by the network operator.
- Install air-source heat pump and associated monitoring & controls equipment.
- Monitor performance, highly critical in particular in the first 6-12 months of operation.

APPENDICES

APPENDIX 1. CARLINN HALL CONSTRUCTION PHASES

2007 – pre-construction

2013 – post phase 1 construction (note not all phase 1 properties complete at this stage)

2017 – construction of phases 2-3 underway

2019 – all phases of house building complete

APPENDIX 2. CHP OPERATION

At the time of writing, electricity consumption data (for the energy centre) has not been made available, this includes current electricity utility unit rates.

There are two CHP units in the Energy Centre for Carlinn Hall, however one is not operational and is unlikely to be repaired. The operating unit is an EC Power XRGI 20 unit. Operational data from the unit was accessed during the site survey via its user interface, see Figure 35.

Figure 35: CHP electrical generation

The operational data accessed via the CHPs user interface reveals that the unit is currently operating at approximately 75% of its capacity with an electrical output of approximately 15kW. Another screen, see Figure 36, showed that the system was currently generating 32kW of heat. Based on this, it is assumed that the current gas input required to facilitate this output is 54kW. If this unit were to operate at maximum capacity, a maximum power output of 20kW and a maximum heat output of 40kW could be achieved.

Figure 36: CHP heat generation

The user interface also showed that the unit's electrical generation over the last 24 hours was relatively stable, at a near-constant 15kW output, see Figure 37. The heat network pumps in the Energy Centre appear to be operating at a fixed speed for the majority of the time. The unit is electrically-led and is set to generate a constant power output of 15kW. This power output is utilised for the plantroom pumps and no power is exported to the residents or the grid.

Figure 37: CHP power output over the last 24 hours

APPENDIX 3. CAPEX SHEETS

BAU

Construction end date	31/12/2024				I
BAU					
Item	**Qty**	**Unit**	**Rate**	**Sum**	**Replacement Period**
BEMS upgrade	1	Qty	15,000	15,000	25
Cost Summary					
Subtotal				€ 15,000	
Prelims	20.00 %			€ 3,000	
PM & Design	10.00 %			€ 1,500	
OH&P	12.00 %			€ 1,800	
Contingency	20.00 %			€ 3,000	
TOTAL CAPEX BAU				**€ 24,300**	
REPEX BAU					
Item	**Sum**	**Next Replacement Year**			**Replacement Period**
Existing Boilers	132,000	2028			20
CHP	25,000	2025			15

Scenario 1 – GSHP

Construction end date	31/12/2024				I
-					
Item	**Qty**	**Unit**	**Rate**	**Sum**	**Replacement Period**
GSHP, large system, 60 deg C incl mech piping	1	Qty	388,500	388,500	20
Thermal Store	1	Qty	115,000	115,000	40
EC Balance of Plant	1	Qty	17,500	17,500	50
EC Power & Controls	1	Qty	24,500	24,500	50
Civils / fencing to hard standing for external plant	1	Qty	34,500	34,500	50
Power Connections, substation, switchboard	1	Qty	300,000	300,000	50
CHP Removal	1	Qty	10,000	10,000	50
Borehole Array	1	Qty	1,351,350	1,351,350	50
Cost Summary					
Subtotal				€ 2,241,350	
Prelims	20.00 %			€ 448,270	
PM & Design	10.00 %			€ 224,135	
OH&P	12.00 %			€ 268,962	
Contingency	20.00 %			€ 448,270	
TOTAL CAPEX GSHP (boreholes)				**€ 3,630,987**	
REPEX for residual plant GSHP (boreholes)					
Item	**Sum**	**Next Replacement Year**			**Replacement Period**
Existing Boilers	132,000	2028			20
Controls	15,000	2023			40

Scenario 2 – ASHP

Construction end date	31/12/2024				
ASHP					
Item	**Qty**	**Unit**	**Rate**	**Sum**	**Replacement Period**
ASHP, large system, 60 deg C incl mech piping	1	Qty	388,500	388,500	15
Thermal Store	1	Qty	115,000	115,000	40
EC Balance of Plant	1	Qty	17,500	17,500	50
EC Power & Controls	1	Qty	24,500	24,500	50
Civils / fencing to hard standing for external plant	1	Qty	34,500	34,500	50
Power Connections, substation, switchboard	1	Qty	300,000	300,000	50
CHP Removal	1	Qty	10,000	10,000	50
Cost Summary					
Subtotal				€ 890,000	222,500
Prelims	20.00 %			€ 178,000	25.70 %
PM & Design	10.00 %			€ 89,000	
OH&P	12.00 %			€ 106,800	
Contingency	20.00 %			€ 178,000	
TOTAL CAPEX ASHP				**€ 1,441,800**	
REPEX for residual plant ASHP					
Item	**Sum**	**Next Replacement Year**			**Replacement Period**
Existing boilers	132,000	2028			20
Controls	15,000	2023			40

Scenario 3 – Biomass

Construction end date	31/12/2024				
Biomass					
Item	**Qty**	**Unit**	**Rate**	**Sum**	**Replacement Period**
Biomass boiler & associated kit	1	Qty	231,000	231,000	20
Thermal Store	1	Qty	115,000	115,000	40
EC Balance of Plant	1	Qty	17,500	17,500	50
EC Power & Controls	1	Qty	24,500	24,500	50
Energy Centre	1	Qty	230,000	230,000	50
Civils / fencing to hard standing for external plant	1	Qty	11,500	11,500	50
Fuel Store	1	Qty	66,000	66,000	50
CHP Removal	1	Qty	10,000	10,000	50
Cost Summary					
Subtotal				€ 705,500	
Prelims	20.00 %			€ 141,100	
PM & Design	10.00 %			€ 70,550	
OH&P	12.00 %			€ 84,660	
Contingency	20.00 %			€ 141,100	
TOTAL CAPEX Biomass				**€ 1,142,910**	
REPEX for residual plant Biomass					
Item	**Sum**	**Next Replacement Year**			**Replacement Period**
Existing boilers	132,000	2028			20
Controls	15,000	2023			40
energy centre // augers & screws etc	15,000	2039			15

APPENDIX 4. TECHNO-ECONOMIC MODELLING

Model Common Factors

Item	Constant
Model length, years	25
Indexation, general	3.00 %
Test Discount Rate[65]	4.0 %
Project Discount Rate	7.12 %

Day 1 Fuel price	€/MWh
Nat. Gas	110
Elec Tariff 1	303
Biomass	144

O&M Item	Cost	Unit
Central GSHP	8	€/MWh
Central ASHP	12	€/MWh
Biomass	15	€/MWh
Gas Boiler	5	€/MWh
Electric Boiler	5	€/MWh

SSRH: *Biomass tariff structure*

Tier	Lower limit MWh/yr	Upper limit MWh/yr	Biomass heating systems tariff c/kWh
1	-	300	5.66
2	300	1,000	3.02
3	1,000	2,400	0.50
4	2,400	10,000	0.50
5	10,000	50,000	0.37
6	50,000		-

Data Sets

Carbon Factors https://www.gov.ie/en/publication/public-spending-code/

(Public Spending Code Supplementary Guidance - Measuring & Valuing Changes in Greenhouse Gas Emissions in Economic Appraisals)

Societal cost of carbon (non-cash item) – based on the figures below for UK and converted to Euroshttps://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

[65] gov.ie - Project Evaluation/Appraisal: Applicable Rates (www.gov.ie)

APPENDIX 5. SITE IMAGES

To be included after final draft agreed.

APPENDIX 6. APROXIMATE PIPE TAKEOFFS

Based on the available drawings, approximate measurement and sizing of residual lengths not shown clearly on drawings, our modelling uses the following length of pipework:

Steel Pre-Insulated Pipework

Size, NB	Qty (m)
32 Flex	-
25	407
32	46
40	102
50	179
65	307
80	72
100	-

All quantities are trench length, and include flow & return pipelines

Plastic Pre-Insulated Pipework

Size, NB	Qty (m)
25	1,361
32	-
40	707
50	438
63	197
75	-
90	232
110	254

All quantities are trench length, and include flow & return pipelines

Building Pipework

Size, NB	Qty (m)
25	462
32	-
40	50
50	-
65	-
80	50
100	100

All quantities are trench length, and include flow & return pipelines

APPENDIX 7. GEOTHERMAL SUBSURFACE DESK STUDY

Produced by Geological Survey Ireland

SEAI Project: "Assess the Viability of Replacing Gas Fuel Sources in Communal Heating Systems with a Geothermal Energy Source."

Case study area: Carlinn Hall, Dundalk, Co. Louth

Geothermal subsurface desk study data provided to SEAI by Geological Survey Ireland

1. Geology

Carlinn Hall is underlain by the Clontail Formation, composed of Silurian calcareous red-mica greywackes (Figure 1). The formation has been described as green-grey, medium to thickly bedded, coarse and very fine-grained greywackes, with dark grey, thinly bedded, poorly graded, quartzose fine sandstone to siltstone units. Both lithologies contain distinctive brown-red coloured biotite. To the north of the site, the younger Carboniferous Dinantian Limestone Formation lies unconformably on the Clontail Formation. Figure 2 shows a cross section through Kingscourt, located southwest of Dundalk town (shown on Figure 3). The Clontail Formation here lies at the base of the cross section, with Carboniferous, Permian and Triassic rocks overlying the formation. The geology underlying the Clontail Formation is currently unknown.

The Clontail Formation mostly dips in a northerly direction and is very steep (70-90 degrees in different areas), suggesting it extends deep into the subsurface. There are no faults recorded by Geological Survey Ireland in the immediate area surrounding Carlinn Hall. Prominent NE-SW trending faults are present further south of Dundalk town towards Dromin (shown in Figure 3). These faults cut through Silurian and Ordovician rocks, suggesting they are younger than Silurian in age. Some NE-SW faults are also present to the west of the site near Kingscourt. A syncline of younger Carboniferous limestones is located further south of Dundalk in Ardee. Subsoil maps from Teagasc indicate that tills derived from Lower Palaeozoic rocks and shales underlie Carlinn Hall.

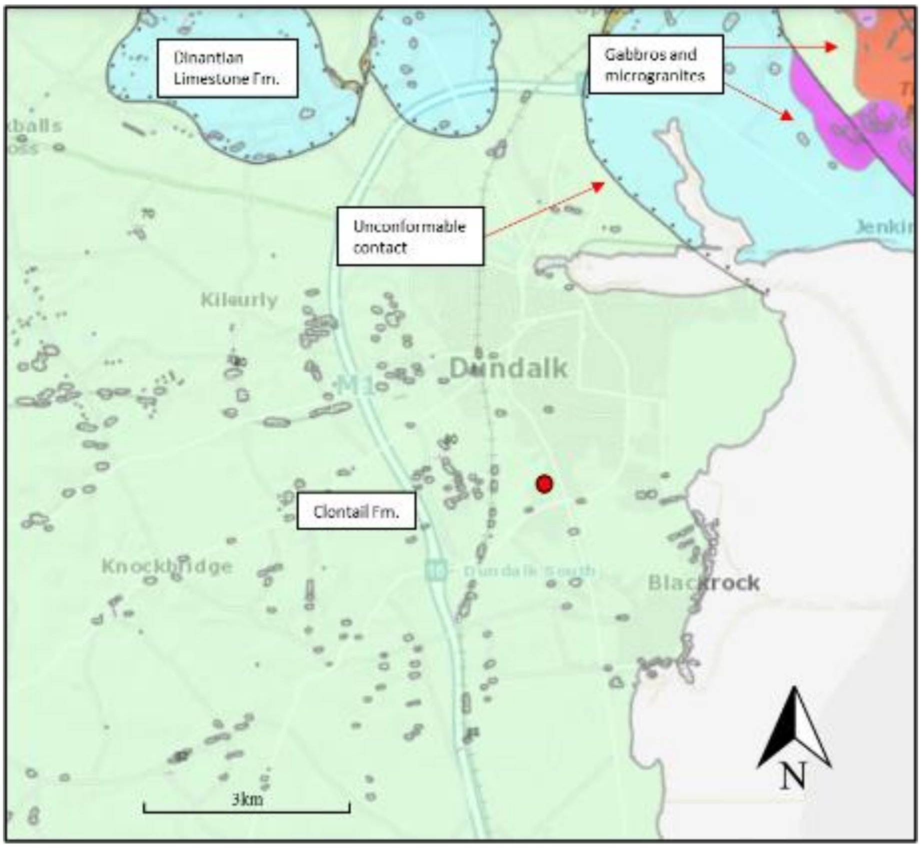

Figure 1. Bedrock geology map of Dundalk, showing Carlinn Hall in red (Source: GSI).

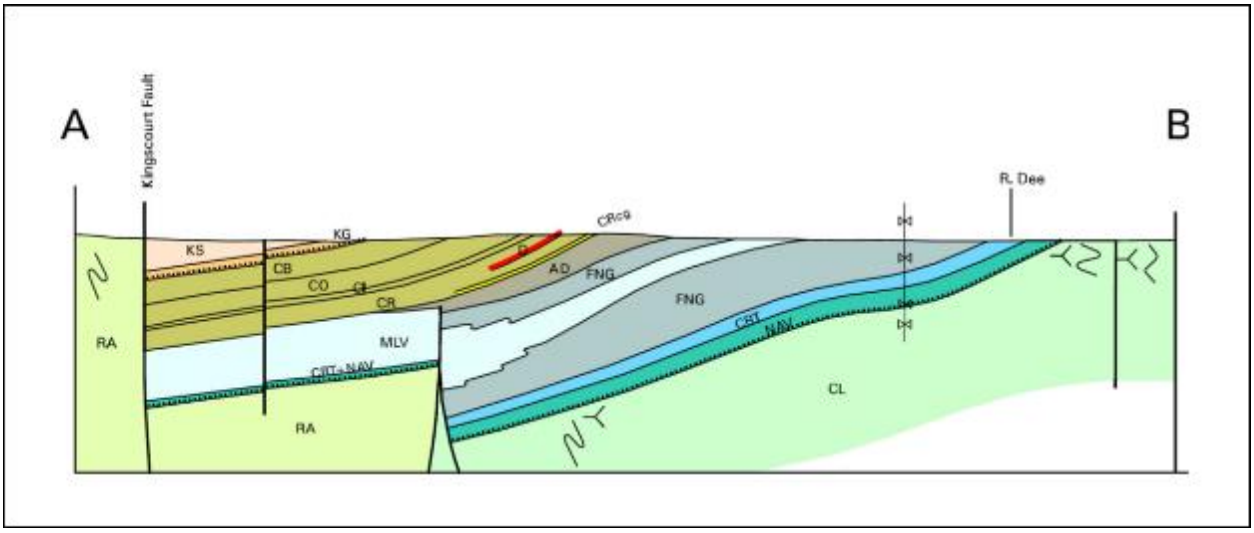

Figure 2. Cross section through various formations southwest of Carlinn Hall. Cross section does not intersect study site. Clontail Formation represented as "CL" in cross section underlying Carboniferous, Permian and Triassic rocks.

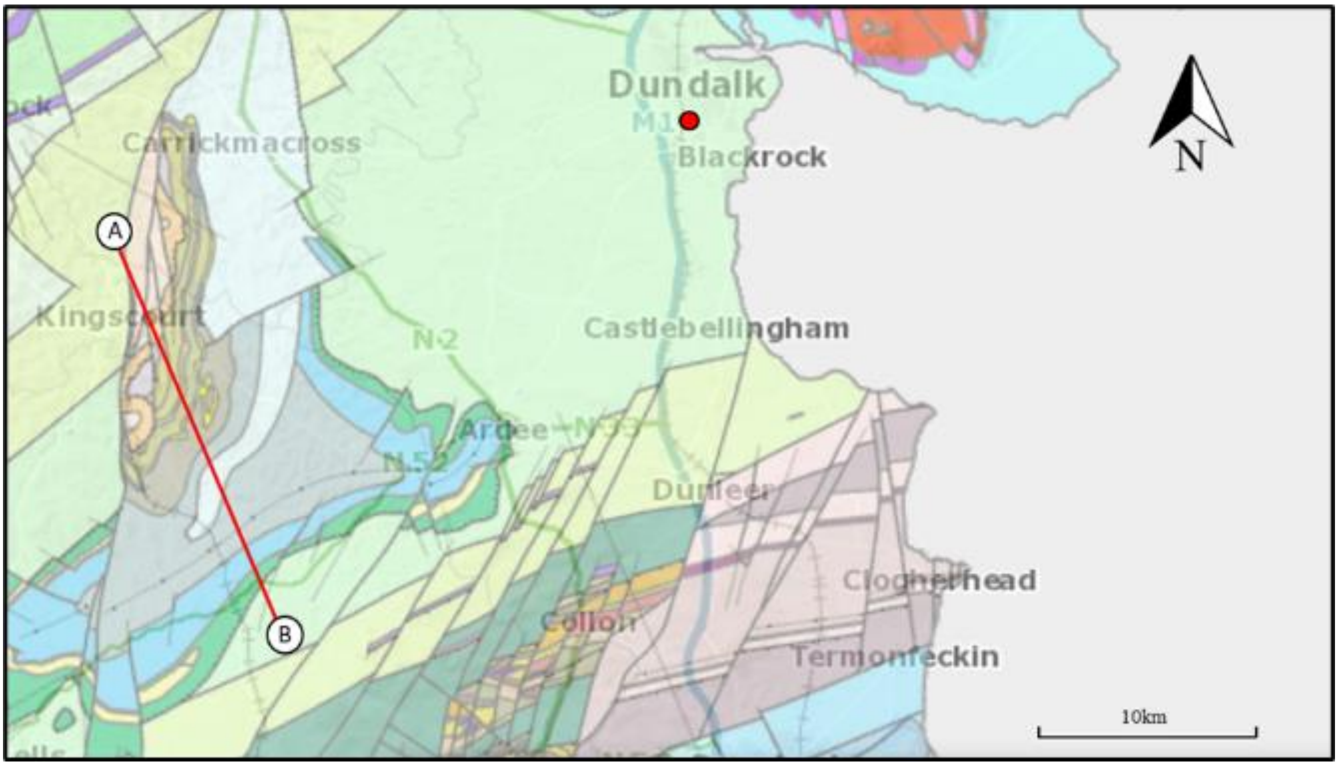

***Figure 3**. Bedrock geology map of Dundalk, showing cross section (A to B) as red line. Prominent NE-SW trending faults shown south of Dundalk town. Carlinn Hall shown in red (Source: GSI).*

Hydrogeology

The GSI have recorded 13 wells in close proximity to the proposed site (Figure 4). 10 wells were reportedly drilled during 1899, with the remaining 3 wells completed in 1998. Information including depth of each borehole, depth to bedrock and groundwater yields were obtained from several of the boreholes (Table 1). These records indicate that groundwater yield in the area is moderate to poor. A bedrock contour map and cross section of the subsurface beneath the site are shown in Figures 5 and 6.

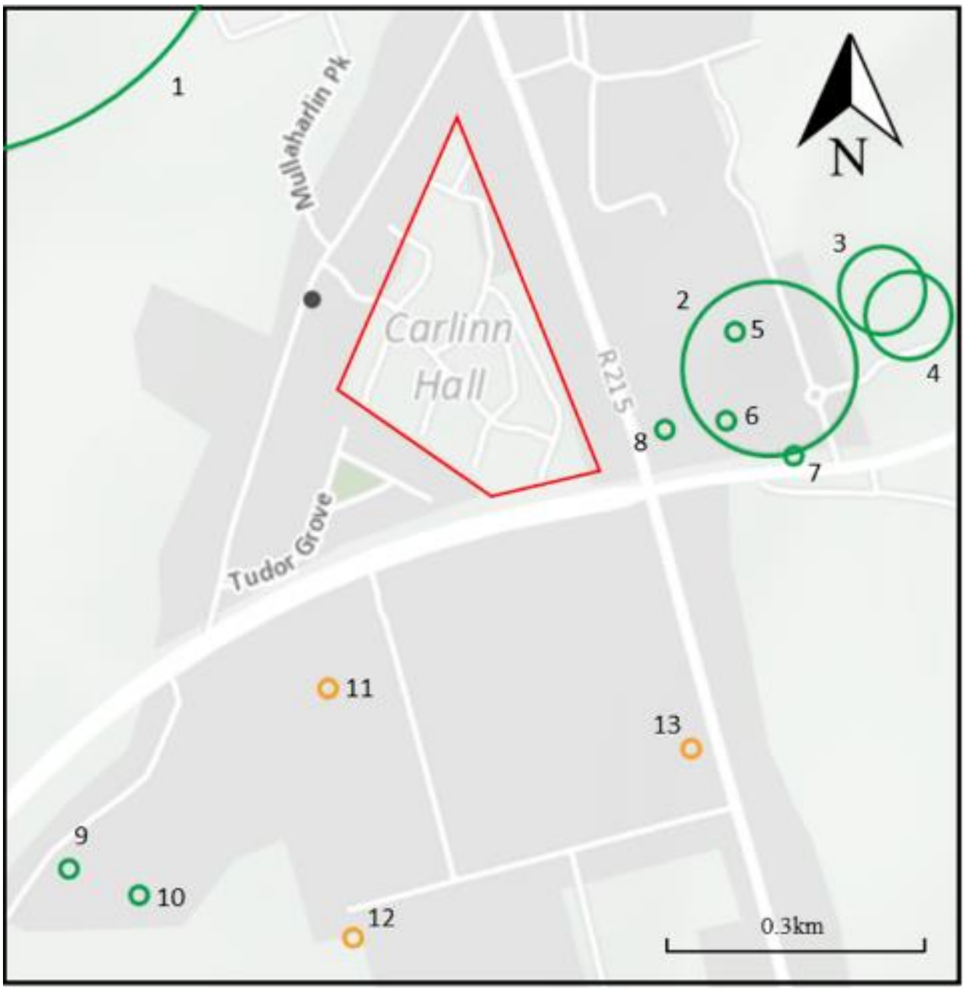

***Figure 4**. Map showing location of wells drilled in 1899 (green) and 1998 (orange). Carlinn Hall shown in red (Source: GSI).*

***Table 1**. Information from boreholes surrounding Carlinn Hall obtained from GSI databases.*

Borehole	Locational Accuracy	Drill date	Depth of hole (m)	Depth to bedrock (m)	GSI Yield Class	Yield (m^3/day)
1	Up to 1km	30/12/1899	1.8	1.2	-	-
2	To 200m	30/12/1899	36.9	7.9	Moderate	54.6
3	To 100m	30/12/1899	9.1	-	Good	218.2
4	To 100m	30/12/1899	25.6	8.5	Poor	21.8
5	To 20m	30/12/1899	10	9	Good	190.1
6	To 20m	30/12/1899	36	8	-	43.2
7	To 20m	30/12/1899	25	8	-	17.3
8	To 20m	30/12/1899	25	8	Poor	8.64
9	To 20m	30/12/1899	54.3	4.6	Poor	7.6
10	To 20m	30/12/1899	20	4.4	Failure	-
11	To 20m	21/08/1998	15	5.2	Failure	-
12	To 20m	18/08/1998	6	-	Good	200
13	To 20m	20/08/1998	10.5	6.2	Moderate	55

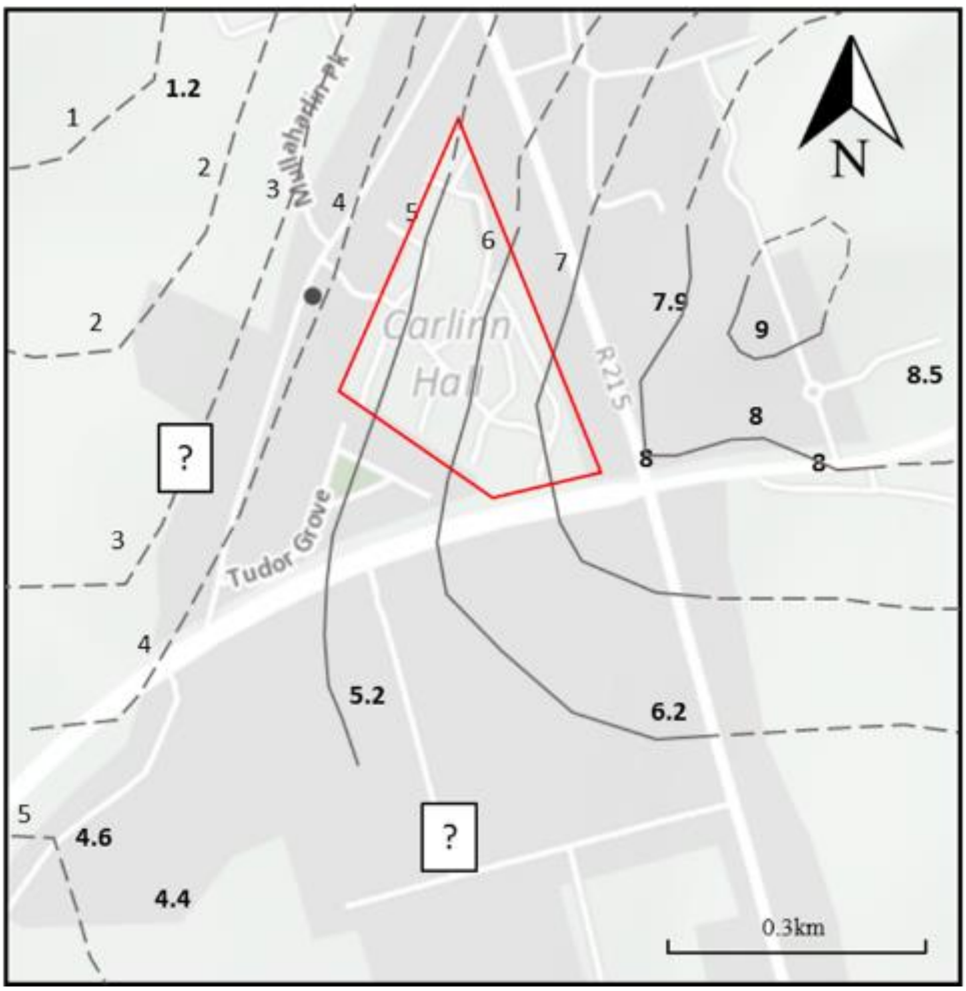

Figure 5. *Bedrock contour map of the surrounding site using depth to bedrock measurements from previous boreholes (in bold). Contours are in metres. Carlinn Hall shown in red (Source: GSI).*

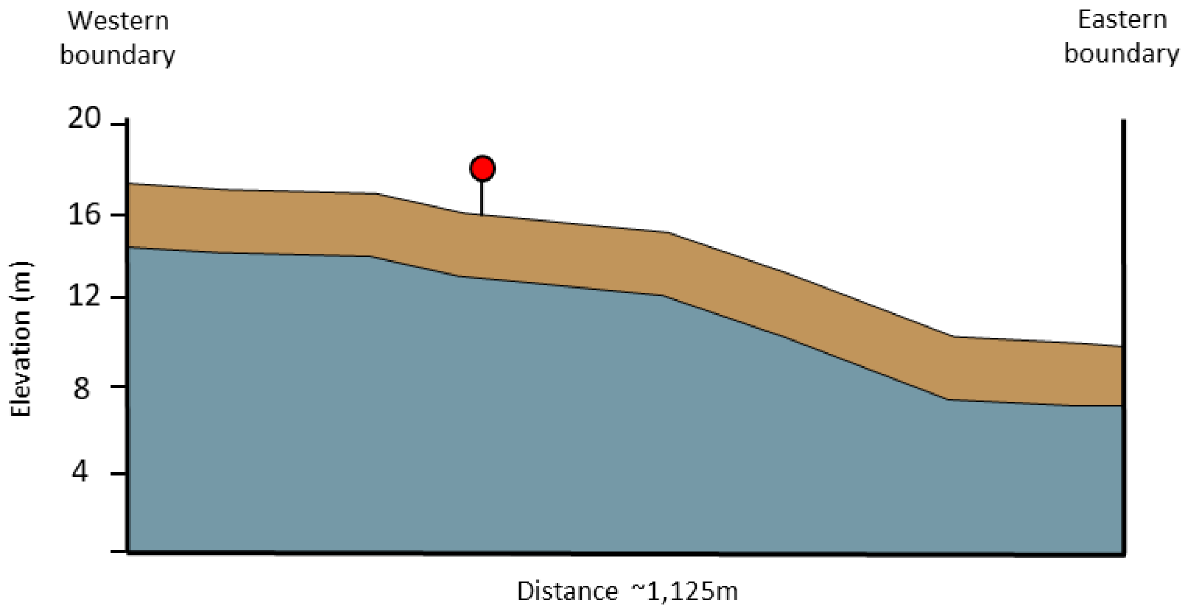

Figure 6. *Geological cross section showing subsoil (till) in brown and bedrock (Clontail Fm. greywacke) in grey. Western and eastern boundaries marked by the extent of Figure 3. Carlinn Hall shown in red.*

Aquifer Properties

The aquifer at this site is classified by Geological Survey Ireland as PI (Poor Aquifer - bedrock generally unproductive except for local zones). The unproductive nature of the aquifer is reflected in the poor yields obtained from some existing boreholes (Table 1). The aquifer to the north of the site is classified as Lg (Locally important gravel aquifer) (Figure 7). An aquifer classified as Lm (Locally Important Aquifer - Bedrock which is Generally Moderately Productive) also lies to the north of Dundalk town. At this location, surface water flows in a northerly direction, eventually discharging into Dundalk Bay (Figure 8). The main groundwater discharges are to the streams and rivers, lakes and any springs or seeps within the groundwater body. Baseflow proportion of the total streamflow is expected to be lower in the PI classified aquifer compared to the surrounding Lg and Lm aquifers. In the absence of inter-granular permeability, groundwater flow in the Clontail Formation is expected to be concentrated in fractured and weathered zones and in the vicinity of fault zones.

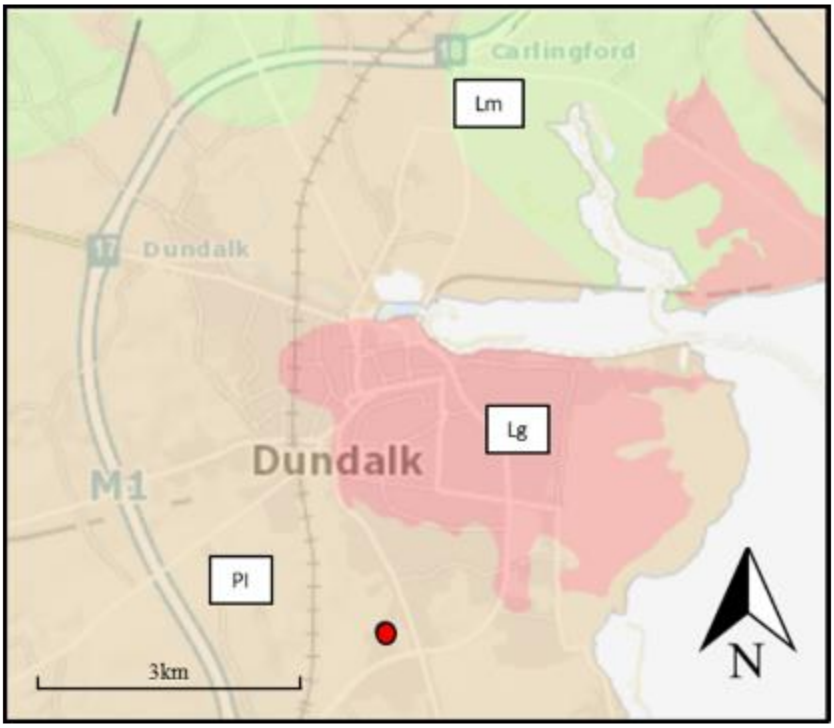

***Figure 7**. Map of aquifer classifications in the surrounding area. Carlinn Hall shown in red (Source: GSI).*

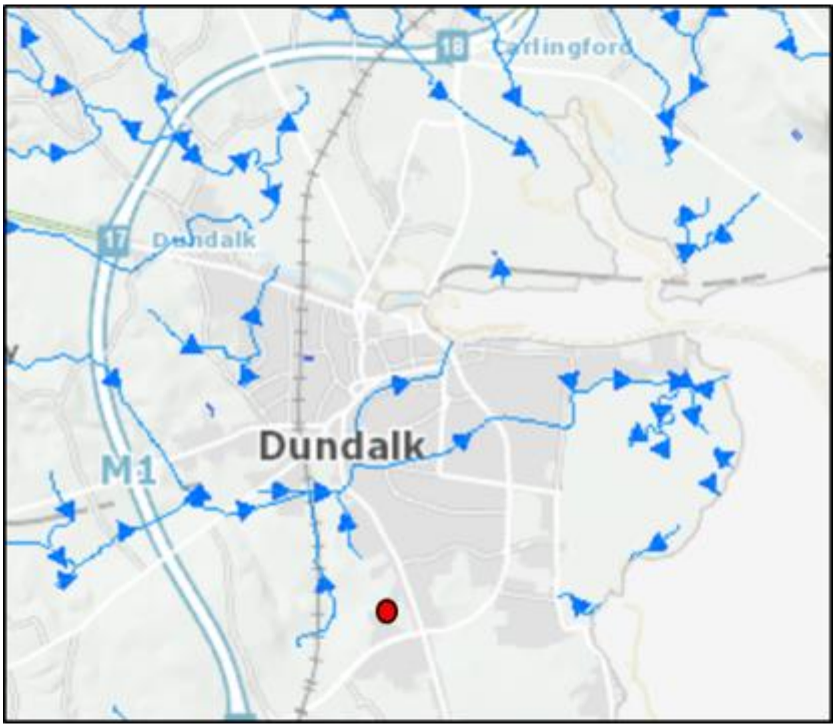

Figure 8. *Map of surface water flow in the surrounding area. Carlinn Hall shown in red (Source: GSI).*

Shallow geothermal properties

Geological Survey Ireland have compiled a map of Ireland that classifies areas based upon their suitability for the installation of closed and open-loop shallow geothermal systems. Carlinn Hall is deemed as "generally unsuitable" for open-loop shallow geothermal energy (Figure 9) due to its poor aquifer classification and deemed as "probably suitable" for closed-loop shallow geothermal systems (Figure 10). This classification indicates that while conditions appear to be favourable, further site-specific assessment is needed to fully ascertain the suitability of the site for closed-loop geothermal systems. Thermal conductivity values of the Clontail Formation are shown in Table 2. Figure 11 shows thermal conductivity values obtained from both bedrock and soil in the Dundalk surrounding area from the Irish Ground Thermal Properties Project.

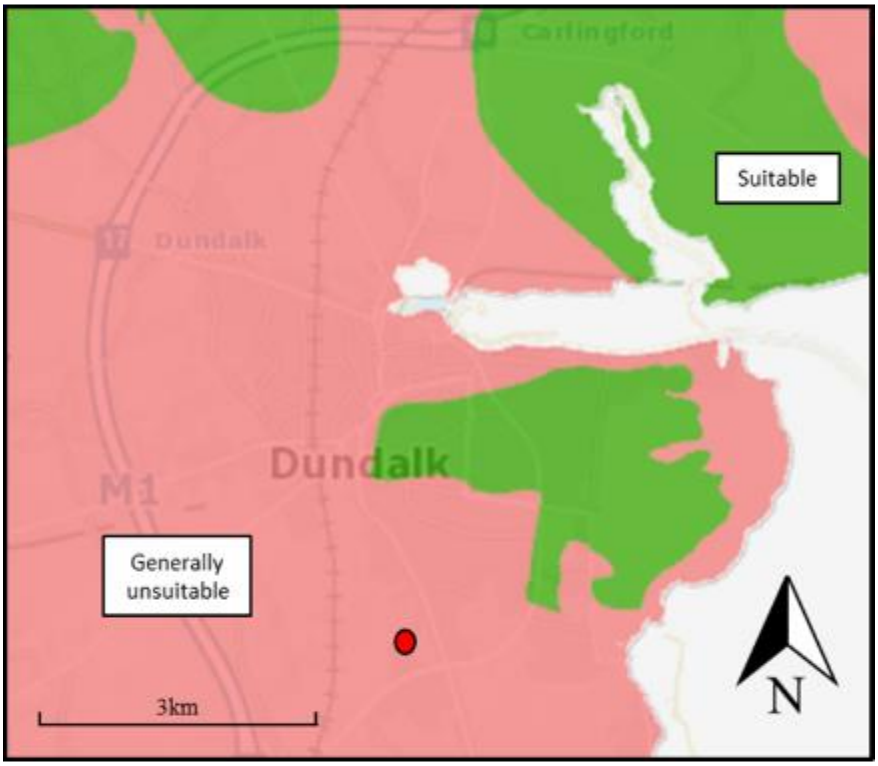

Figure 9*. Map showing suitability of open-loop geothermal systems in the surrounding area. Carlinn Hall shown in red (Source: GSI).*

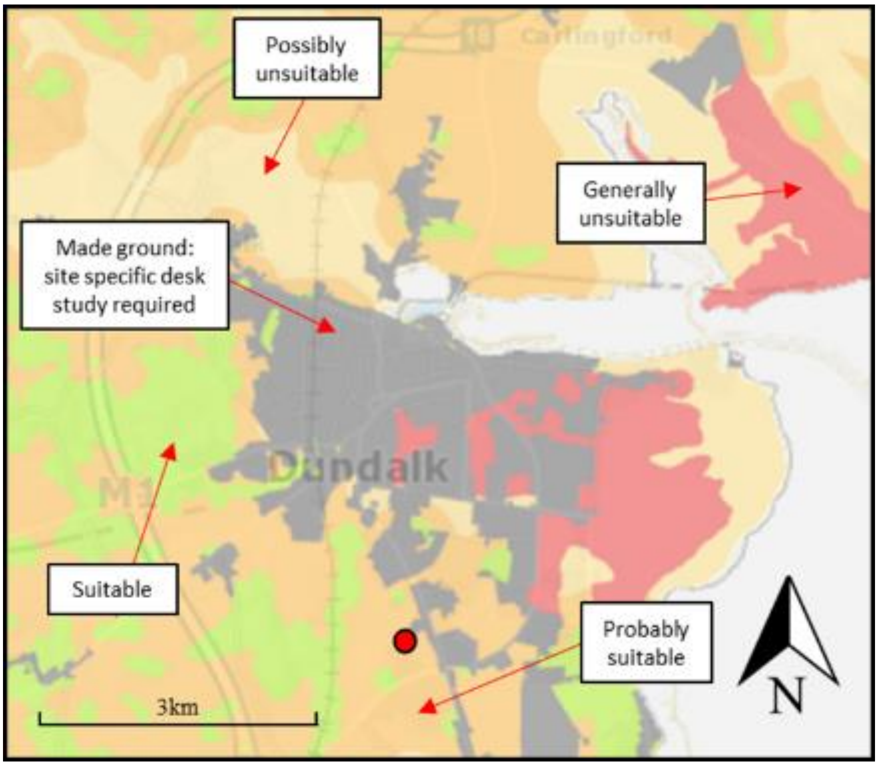

Figure 10*. Map showing suitability of closed-loop geothermal systems in the surrounding area. Carlinn Hall shown in red (Source: GSI).*

***Table 2**. Thermal Conductivity (TC) values of the Clontail Fm.*

Formation name	Rock type	Location	IGTP class	Saturated TC (W/mK)	Easting	Northing
Clontail Formation	Calcareous red-mica greywacke	Aghnaskeagh	Sandstone	1.40 – 2.10	307,144	313521

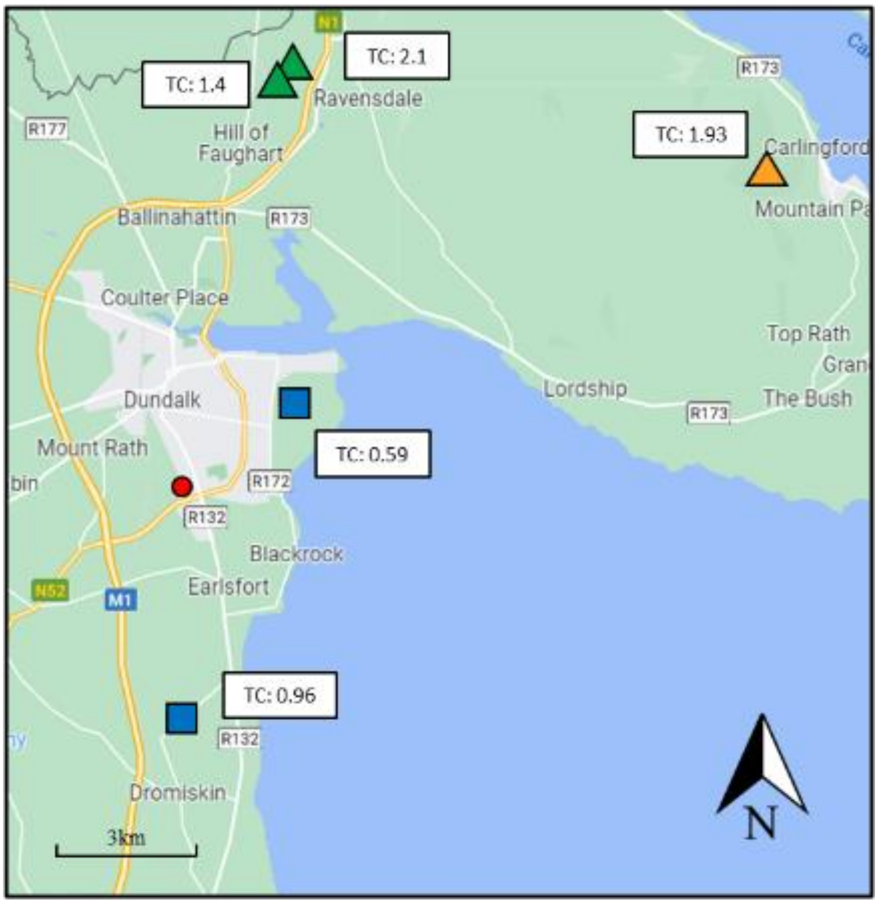

***Figure 11.** Map showing compilation of thermal conductivity (TC) data from different Irish Bedrock formations and Quaternary lithologies. Bedrock thermal conductivity values are shown as triangles, obtained from IGTP3 (green), IGTP2 (blue) and IGTP1 (orange). Squares represent soil thermal conductivity values obtained from IGTP3. IGTP 1, 2 and 3 refers to phases of the overall IGTP Project. Carlinn Hall shown in red (Source:* http://irishgroundtherm.com/results/*).*

As Carlinn Hall is located within a greywacke sandstone formation and previous investigations have suggested poor groundwater yields, it is likely that a closed-loop shallow geothermal system would perform better than an open-loop system. An exploratory borehole should be drilled on site to allow more accurate hydrogeological and geothermal parameters to be measured.

Deep geothermal potential

This feasibility study will assess only the shallow geothermal potential of the site (in this case shallow is defined as surface to approximately 400 m below ground level). Geothermal gradients in Ireland are generally poorly constrained, however, a recently completed 1 km borehole in Dublin City yielded a bottom hole temperature of 38 ˚C, giving an average geothermal gradient of 28 ˚C/km. Geological Survey Ireland have published a suite of deep temperature maps of the Irish crust (GSI, 2021). Figure 12 shows approximate temperatures at a depth of 2.5 km beneath the surface. These maps are based upon a probabilistic thermal model of the Irish crust and as such, there is a degree of uncertainty inherent in the dataset (see Mather et al., 2018; Mather & Fullea, 2019). The temperature values mapped here should be viewed as guideline only and not as absolute values. The actual temperature at depth may vary from the temperatures shown in these maps. Nevertheless, the dataset is the most up-to-date and realistic representation of Irish crustal temperatures that is currently available. Figure 12 clearly demonstrates the elevated deep geothermal potential in Northern Ireland and Co. Louth as a result of past igneous activity. It is unclear whether this elevated potential exists at shallow depths also (0 – 400 m).

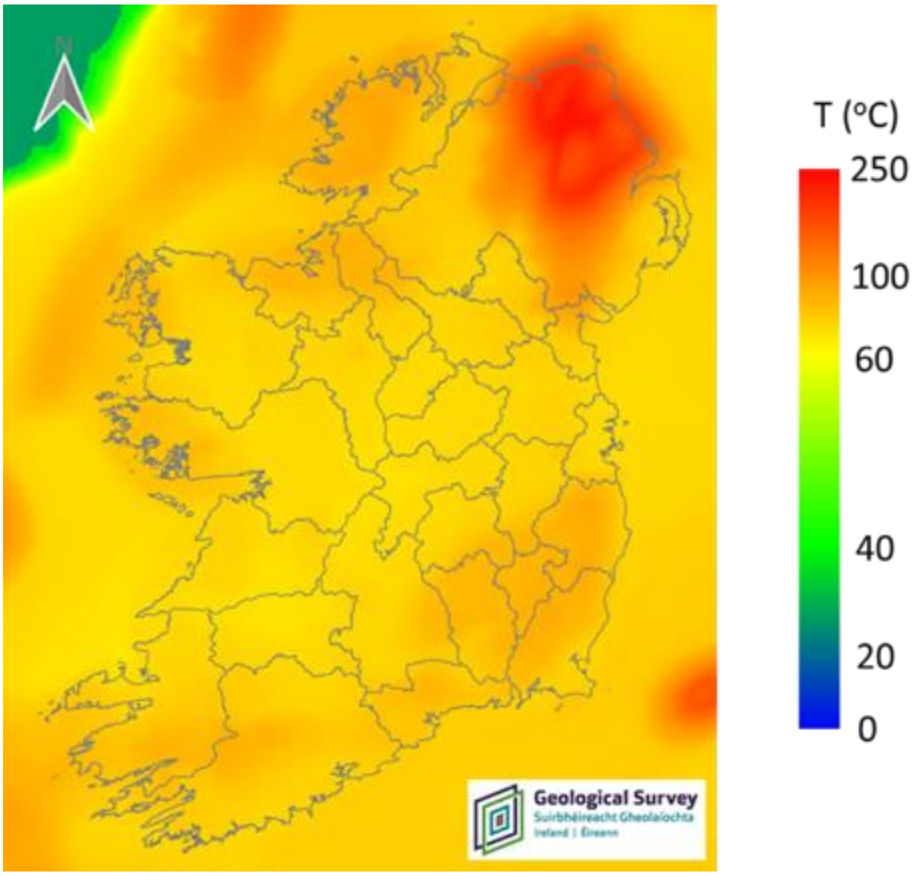

***Figure 12**. Modelled deep temperatures at 2.5 km beneath the surface. From GSI (2021).*

***Table 3**. Subsurface temperatures in the Carlinn Hall area based on a conservative gradient of 28 ˚C/km. The gradient in Dundalk may be higher due to increased heat flow in the north of Ireland.*

Depth below surface	Temperature (^{o}C)
5000m	150
2500m	80
1000m	38
500m	24
100m	13
10m	9 – 11*

*average temperature of shallow groundwater in Ireland.

APPENDIX 8. AIR POLLUTION CALCULATIONS

The following emission parameters have been included in our air pollution calculations:

- PM2.5
- NOX
- NMVOC
- SOX

Emissions factors used in the calculations are shown in Table 35. These are based on dry-bottom boiler combustion and for biomass it is based on wood and wood waste (clean wood waste) – these are detailed in the emission database which is downloaded the National Atmospheric Emissions Inventory from: https://naei.beis.gov.uk/data/ef-all. Note that whilst the information has been downloaded from NAEI, the combustion data is not region specific and can be applied to the Irish context.

Table 35: Air quality – pollutants used in the air quality costs. The units are shown as g/GJ and t/MWh for

Fuel	PM2.5	NOX	NMVOC	SOX	Unit
Natural Gas	0.89	89	2.6	0.281	g/GJ
Biomass	133	81	7.31	10.8	g/GJ
Natural Gas	0.00000024722	0.00002472222	0.00000072222	0.00000007806	t/MWh
Biomass	0.00003694444	0.00002250000	0.00000203056	0.00000300000	t/MWh

These values have been translated into c/kWh figures by using the "Valuing Greenhouse Gas Emissions in the Public Spending Code" document prepared by the Irish Government Economic and Evaluation Service (IGEES)[66]. This is a 2019 document that provides estimated damage costs of non-greenhouse gas pollutants. These are shown in Table 36.

Table 36: Non-greenhouse gas pollutant estimated damage costs

	PM2.5 (note1)	NOX	NMVOC	SOX	Unit
Rural (note 2)	16,512	5,688	1,398	6,959	Euro/tonne
Suburban (note 2)	47,420	5,688	1,398	6,959	Euro/tonne
Urban (note 2)	194,660	5,688	1,398	6,959	Euro/tonne

[66] https://assets.gov.ie/19749/77936e6f1cb144d68c1553c3f9ddb197.pdf

Note 1: The PM2.5 values are disaggregated by rural, suburban, and urban exposure, to reflect the increased damage costs in more densely populated areas where human exposure is higher.

Note 2:Urban relates to towns/settlements greater than 50,000 population, suburban relates to towns/settlements between 1,500 and 49,999 population and rural relates to areas with less than 1,500 population. For Dundalk, the suburban category is used.

The data in Table 36 can then be combined with that in Table 35 to produce c/kWh of fuels that have then been used in the air pollution calculations in the TEM. The values in Table 37 and Table 38 are based on 2019 figures (as this is when the IGEES document is dated) – these values are index linked in the TEM (i.e., the 2023 figures are higher)

Table 37: Air pollution costs used in the TEM for natural gas

Natural Gas	c/kWh				
	PM2.5	NOX	NMVOC	SOX	SUM
Rural	0.04	1.41	0.01	0.01	1.46
Suburban	**0.12**	**1.41**	**0.01**	**0.01**	**1.54**
Urban	0.48	1.41	0.01	0.01	1.90

Table 38: Air pollution costs used in the TEM for biomass

Biomass	c/kWh				
	PM2.5	NOX	NMVOC	SOX	SUM
Rural	6.10	1.28	0.03	0.21	7.62
Suburban	**17.52**	**1.28**	**0.03**	**0.21**	**19.04**
Urban	71.92	1.28	0.03	0.21	73.43

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