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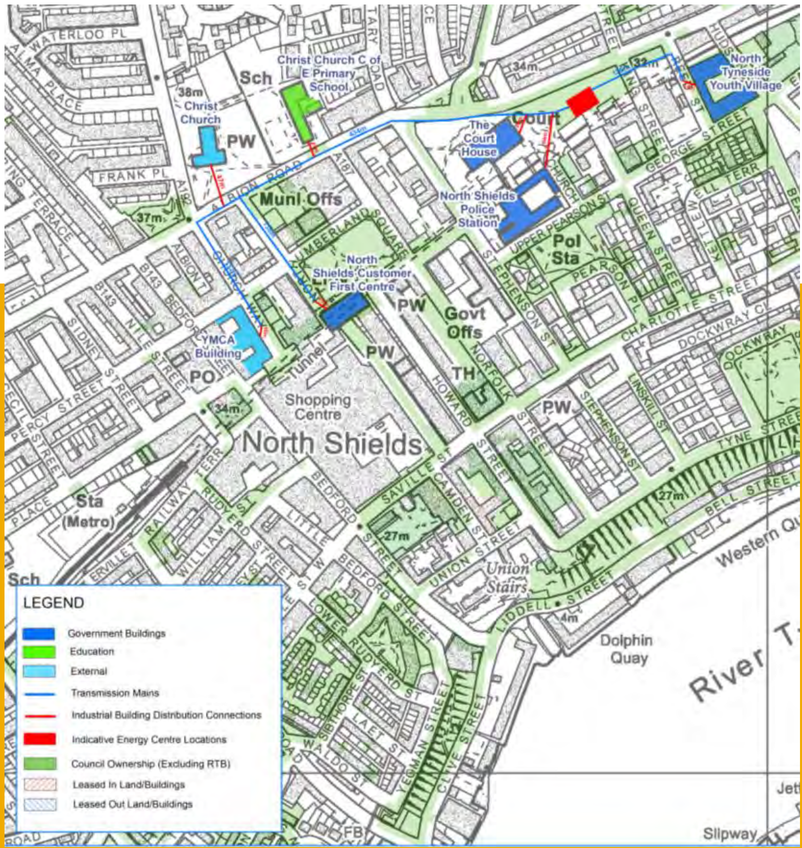

Project:
DECC HNDU Energy Master-Planning & District Heating Feasibility Study for North Tyneside Council (2015/16)

Energy Master-Planning Report

Revision draft for review - October 2016

Quality Management

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1.0 Executive Summary

1.1 Background to the Master-Plan

Following North Tyneside Council's success in securing grant funding from the Department of Energy and Climate Change (DECC) under their Heat Network Development Unit Programme (HNDU) a Heat Mapping exercise was undertaken by Capita on behalf of the Council as a preliminary stage prior to this Energy Master-Planning study. The key output of the Heat Mapping stage (NTC Heat Mapping report: EMDH-HM:V1.1 2016) was the identification of six areas (heat clusters) within the borough of North Tyneside which could potentially support a district heating network, as highlighted by figure 1 below.

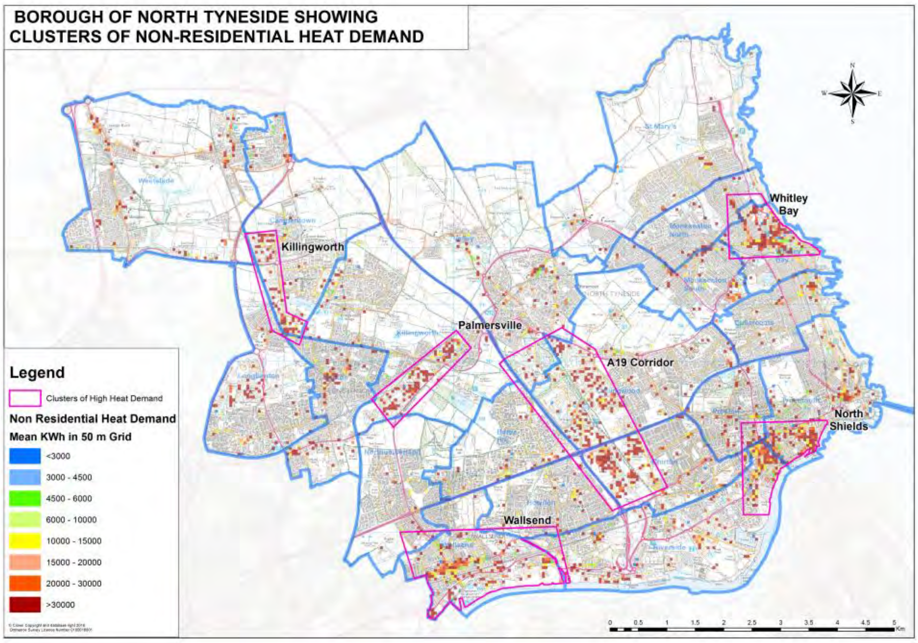

Figure 1: Clusters of non-residential heat demand density in North Tyneside

1.2 Assessing the Options

In undertaking the Energy Master-Planning, a further detailed analysis of the clusters identified above has been completed, prior to undertaking a review of zero and low-carbon technology options relevant to the North Tyneside borough. Based on the outcomes of this cluster analysis and technology review a range of heat network models have been developed to generate network proposals for the cluster areas identified. This modelling has identified high-level system capital (Capex) requirements, along with indicative revenue and operational (Opex) costs. A subsequent Techno-economic assessment was undertaken to provide a prefeasibility analysis of these heat network proposals across a number of technology options. The financial performance of these modelled networks was then assessed against a range of agreed appraisal criteria to provide an analysis of each system proposal.

1.3 Master-Planning Findings & Recommendations

Of the six model networks assessed, whilst a number were not robust enough to pass a range of feasibility tests, three were found to present viable proposals (as highlighted in table 1).

Table 1: Recommended Systems for Feasibility Analysis

System	Technology	Cost (£)	25 Year NPV (£)	IRR %	40 Year NPV (£)	IRR %	Capital Offset required (£)	Load Risk	Annual CO2 abatement (tonnes)
A19 North	Gas CHP & TU PW	2,408,391	1,156,003	11	1,811,237	12	-	66% High Load Risk 4 of 6 Buildings non-NTC	1,320
	Gas-Bio PW	2,803,494	1,221,781	11	1,960,791	12	-		1,654
A19 South (Phase 1)	Gas CHP & TU PW	730,556	16,822	6	151,763	8	-	0% No Load Risk 0 of 5 Buildings non-NTC	305
	Gas-Bio PW	994,098	-10,366	6	166,898	7	-		474
Killingworth	Gas CHP & TU PW	2,022,047	452,933	8	904,094	10	-	17% Low Load Risk 1 of 6 Buildings non-NTC	948
	Gas-Bio PW	2,338,495	344,416	8	831,894	9	-		1,092

Note: **A separate report supplement document provides technical and financial detail with supporting graphics to accompany the proposal analysis sections. The supplement is intended to be read in conjunction with the main report to provide further detail to support the narrative where necessary to avoid having to scan back and forth through multiple pages.**

Although further detail is provided for each modelled proposal in the recommendations section towards the end of this report, each of the three shortlisted proposals identified in table 1 meet the key financial appraisal requirements defined in the brief in terms of NPV and IRR targets. They also meet with the associated risk and carbon reduction aspirations.

A further stage of detailed analysis at a finer grain would be required before any final decisions on viability can be drawn. A subsequent stage of high-level feasibility analysis would allow the further testing of each proposal using more sophisticated financial and cost analysis techniques. It is our recommendation that the positive outcomes of this Master-Planning exercise in terms of the viable proposals identified are taken forward for further feasibility analysis.

We understand that budgetary constraints at the subsequent stage of this work restrict the Council to a detailed analysis of only two network proposals. On this basis we would recommend that the identified risks associated with the A19 North proposals are given serious consideration, with the recommendation that the Killingworth and A19 South (Phase 1) proposals are given preference in light of their deliverability. Although we appreciate that the final decision can only be taken by the Council in consideration of each of the proposals on their own merits

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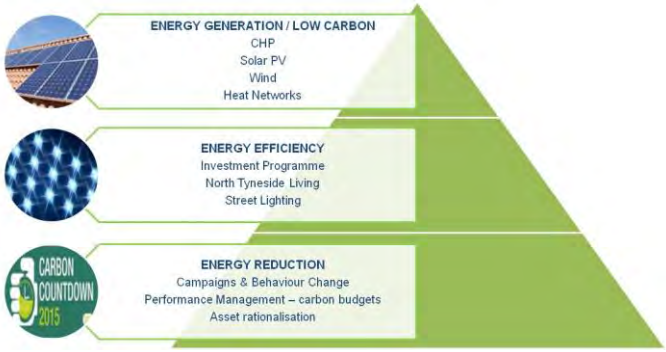
2.0 Introduction

The NTC Energy Hierarchy – energy reduction, energy efficiency, energy generation.



The NTC Carbon Reduction Target

The Council has adopted the National Government carbon reduction target for this plan;

50% carbon footprint reduction by 2027 against the 2010/11 baseline.

This is an ambitious target and whilst challenging, it will continue to motivate and influence the Council and its partners. The Council recognises that both external and internal factors will influence our trajectory towards the target and we will regularly monitor progress and apply performance management and governance through the Council's Environment Board.

The NTC Vision

In order to focus actions of the Council and its partners to achieve this challenging target through action planning and delivery between 2016 and 2027, the Council has agreed to adopt the simple vision which is;

"To build on the principles of good energy management, by developing a range of low and zero carbon energy projects which reduce our carbon footprint and maximise income generation opportunities."

NTC Low Carbon Plan Strategic Objectives:

- **Strategic Objective 1**: Energy Reduction
- **Strategic Objective 2** Energy Efficiency
- **Strategic Objective 3:** Energy Generation and Income
- **Strategic Objective 4:** Fuel Poverty

Figure 2: Key aspects of North Tyneside Councils Low Carbon Plan 2016-2027

The excerpts in figure 2, taken from the Council's Low Carbon Plan 2016-2027, highlight the public commitment the organisation has made to leading Carbon reduction efforts across the North Tyneside Borough. Capita welcome the opportunity to support the Council in the production of this Energy Master-Planning Study as part of the Authorities wider Low-Carbon Objectives.

North Tyneside is one of five metropolitan districts within the Tyne and Wear conurbation, with an area of approximately 82 square kilometres. It has the North Sea to the east, the River Tyne to the south, and Newcastle City to the west. Northumberland County forms the northern boundary. The Borough has no single main centre. Instead it includes the four town centres of Wallsend, North Shields, Whitley Bay and Killingworth. There are a number of District Centres associated with residential areas. Within the Borough the out-of-centre retail is focused on the Silverlink Retail Park and also at Royal Quays, close to the Port of Tyne. Residential areas form a broad 'U' shaped pattern in the Borough, bordering Newcastle to the west, running east/west north of the River Tyne and north/south along the Coast. In the northern area of the Borough are a number of former mining villages and the most recent areas of major new housing growth at Shiremoor and Backworth.

District heating networks served by a diversity of different low-carbon heat sources, including combined heat and power systems, present a potential solution to a number of existing and emerging issues in the built environment such as dramatically escalating energy costs, carbon emissions and sustainability concerns, as well as fuel poverty and energy security issues. Despite the success of a number of large Northern-European, and some British district heating networks, their implementation in the UK remains limited.

A number of factors such as the potentially prohibitively high cost of establishing networks, the length of return on the significant capital investment, and the considerable complexities involved in planning, engineering and delivering these networks, are often cited as the reasons why there are limited examples of schemes in the UK. Regardless of these complexities, current energy strategy still promotes the implementation of district heating in dense urban areas, and most metropolitan Local Authorities are currently at different stages in exploring district heating opportunities in their boroughs.

To encourage the wider implementation of large-scale district heating networks in the UK, decentralised energy planning must be addressed at the local level in-line with the urban planning framework, and ideally, should become a core function of the spatial planning process.

The aim of this document is to both provide a framework to assist in this local-level analysis and also to undertake a high-level pre-feasibility analysis of the potential district heating opportunities identified during the previous heat-mapping stage.

3.0 Methodology

3.1 Stakeholder Engagement - Internal

Internal engagement sessions were held with a range of potential internal stakeholders from across the Authority including representatives from NTC Planning, Housing, Highways Engineering, Property Services, Leisure Services, and Commercial Services teams both at the Heat Mapping and Master Planning stages. Subsequent outputs at both stages were distributed to this group for consultation. More regular and ongoing dialogue has been held with the Planning, Property, and Highways teams to ensure input has been sought on pre-feasibility proposals.

3.2 Stakeholder Engagement – External

Contact was also made with local District Network Operators (DNO), a meeting was held with representatives from Northern Power Grid (NPG). Whilst NPG were unable to provide any detailed guidance due to the outline nature of the proposals at this pre-feasibility stage, they were able to look at both the mapping outputs and the system proposals and were able to advise that there were no existing supply or export capacity constraints with the local network in any of the six proposal locations. With regards the gas DNO, Northern Gas Networks (NGN), in the absence of a formal connection request being able to be made, it was not possible to secure detailed input. Although, a phone call was able to confirm that on the basis that each of the system proposals involve the retrofit of networks to existing buildings already served by the local gas network. This should not present any constraints as there would be no major net increase to the capacity demand on the local network in those locations. Further engagement with each of the operators will be undertaken at the subsequent stages as further design level detail emerges, at which point more detailed discussions will be able to be held, and formal connection requests submitted where appropriate.

At the previous heat-mapping stage a Macro-level borough-wide analysis was undertaken (NTC Heat Mapping report: EMDH-HM:V1.1 2016) using data drawn from a number of sources to create a series of heat maps for the North Tyneside Council (NTC) administrative area which identify the geographical heat demand density across the borough. From the outset the project team were keen to use actual building consumption data wherever possible. This was no issue with regards to data for the Council's operational buildings, however obtaining actual building consumption data for private buildings within a heat-mapping study area is known to be difficult. Prior to commencing the heat mapping analysis the project team engaged with the NTC Economic Development service to send out a communication to a list of 60 of the largest companies within the borough as well as other public sector organisations that NTC is in regular contact with. This communication explained both the aims of this study and need for support from local enterprises in developing a robust consumption dataset, the communication was accompanied by a letter of authority to be completed and returned by cooperating parties to allow the project team to approach suppliers directly for data. Disappointingly, there was no response from any of the letters sent out, only the Northumbria

Police service provided half hourly data for their Cobalt building when they were contacted via existing networks.

3.3 Data Methodology

In absence of actual consumption data, work was commenced to create a hybrid/composite data-set using data drawn together from a number of sources. The data used for NTC's operational portfolio was constructed from a 3 year average of consumption data for NTC operational sites taken from the NTC Energy Management System (TEAM-Sigma), this was augmented by the Half-hourly data available for NTC AMR sites. All of NTC's gas supplies are now half hourly metered, however, only Profile Classes 1 & 2 for electricity supplies are half-hourly metered.

> *Note:* **The key output of the heat mapping exercise was the identification of six areas (heat clusters) where the density of heating demand was above an indicative benchmark density which could potentially support a district heating network.**

In undertaking this subsequent energy master-planning study to further evaluate potential network opportunities, we must first revisit the heat mapping outputs (clusters identified) to examine the point level or building level data. This further analysis aims to identify individual buildings with both significant heat demand and a reasonably constant demand profile which could potentially act as anchor heat customers to underpin a heat network.

Once these clusters have been assessed further and potential anchor buildings identified, pre-feasibility system modelling will be undertaken to explore the different technology options that are suitable for each network proposal. This Techno-economic system modelling will identify high-level system capital requirements, along with indicative revenue and operational (opex) costs. A further analysis will be undertaken to assess the financial performance of each modelled network proposal across a range of agreed appraisal metrics.

The outcomes of the pre-feasibility system modelling and financial analysis will be used to evaluate each network proposal with recommendations being made for further high-level feasibility analysis of the most robust network options.

3.4 Future Development Sites

In terms of historical development throughout North Tyneside the borough has seen significant residential development in the years from 2000 onwards, although recent non-residential development has been more limited. Whilst the borough could not be considered a dense urban area, benefiting from considerable green open space in the Northern wards, the former industrial areas along the Northern banks of the river Tyne provide higher development density. Recent non-residential, including retail & commercial office, development has concentrated along the Northern end of the A19 corridor (Silver-link & Cobalt developments), with some light industrial development at the Southern end of the A19 corridor (Tyne Tunnel Trading Estate).

3.4.1 Residential development

To assess the future residential load within the borough the Strategic Housing Land Availability Assessment (SHLAA) was interrogated and a shortlist created of 61 housing sites where full permission had been granted, within these sites the number of dwellings being delivered over next five years and 6-10 years were recorded (figure 3). This approach was agreed on the basis that only sites with full planning permission, and only the number of dwelling units being delivered over the next 10 years would provide the level of certainty required for a network feasibility study.

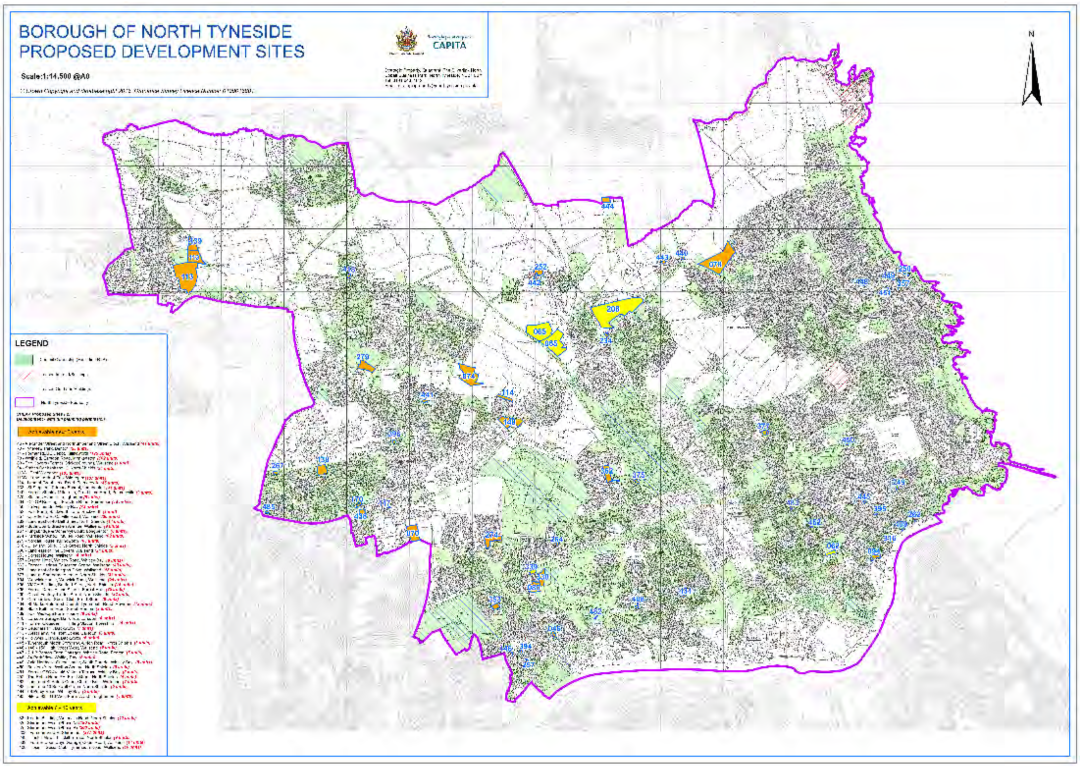


Figure 3: initial shortlist of NTC residential development sites

Following a survey of planning applications submitted for these sites it was clear that only the larger sites with higher dwelling numbers provided space standards for the proposed dwellings which would allow likely heating loads to be derived using heating benchmarks . The NTC Planning team advised that developers often employ bespoke architectural design on smaller-scale residential developments whereas the volume house-builders who bring forward larger sites have off-the-shelf housing types which are delivered across multiple sites. On this basis the list was narrowed down to sites delivering over 40 dwelling units bringing the list of sites down from 61 to 14 sites (figure 4).

There is a further logic to this approach in that developers of sites with less than 40 units may not be willing to consider district heating as an option for a site of that size.

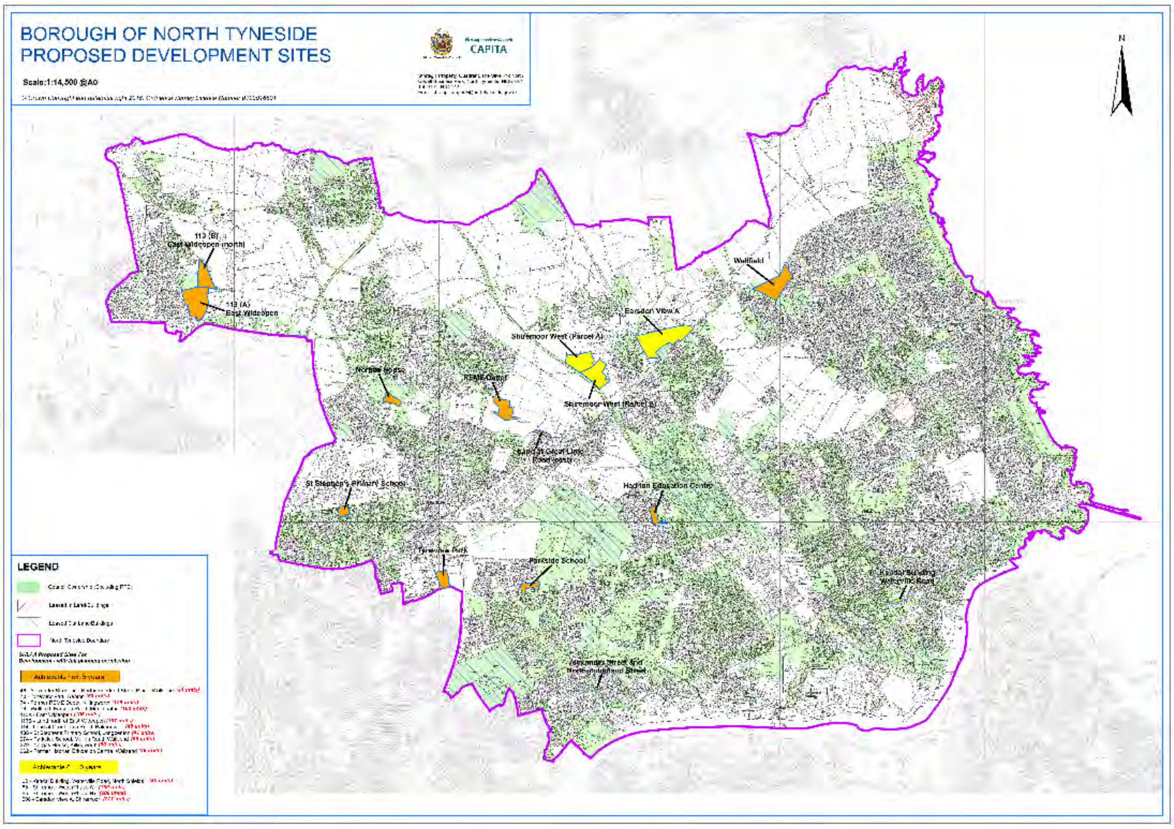


Figure 4: Shortlisted NTC residential development sites

Of the 14 remaining sites the site master-plan and accommodation schedules were interrogated to ascertain an overall square meter figure for the various dwelling units being delivered. The Building Regulations Part L (2013) Target Fabric Energy Efficiency rate (TFEE) for dwellings (54.26 kWh/m2 per year) was then applied to derive the future annual heating load (Table 2).

Table 2: NTC Residential development sites

Site Name	next 5 years	6 to 10 years	Total	GIA (m2)	Site modelled Heat requirement (Part L 2013 TFEE: 54.26kWh/m2/year)
Alexander Street & Northumberland Street Block, Wallsend	41	0	41	3051	165,547
Shiremoor West (Phase A)	120	60	180	22495.54069	1,220,608
Shiremoor West (Phase B)	120	80	200	22104	1,199,363
Tyneview Park, Benton	53	0	53	5946.05	322,633
Former REME Depot (Killingworth Stores), West Lane, Killingworth	125	0	125	14026.69	761,088
Wellfield, Earsdon Road, Monkseaton	162	0	162	25725.26	1,395,853
East Wideopen	105	0	105	9433.807135	511,878
Land north of East Wideopen	107	0	107	Dwelling unit sizes not provided - under query with developer*	
Land at Great Lime Road (east), Palmersville	45	0	45	6210.38	336,975
St Stephen's Primary School, Bardsey Place, Longbenton	41	0	41	Dwelling unit sizes not provided - under query with developer*	
Earsdon View A , Land north of Shiremoor	240	37	277	21804.03	1,183,087
Parkside School, Mullen Road, Wallsend	69	0	69	Dwelling unit sizes not provided - under query with developer*	
Norgas House, Killingworth	63	0	63	5036.25	273,267
Hadrian Education Centre, Addington Drive, Wallsend	49	0	49	4924.33	267,194

**note 3 of the 14 sites did not state dwelling unit sizes within the planning application, this is under query with the developer and figures will be provided once they have been made available.*

In terms of residential development beyond these sites the Council's planning function are currently working to have their local plan adopted by early 2017. Two of the key developments within this plan are the large housing sites at Killingworth and Murton (Killingworth Moor up to 2000 dwellings, and Murton Gap up to 3000 dwellings). The Council's planning team are presently working with a consortium of developers to bring these sites forward with a full planning application anticipated mid to late 2017, with delivery commencing from 2018 onwards. Whilst there is insufficient detail available to undertake a detailed analysis of these opportunities at present, a high-level analysis has been included in the relevant proposal sections.

3.1.2 Future Non-Residential development

Whilst the Council are working towards having their local plan adopted in early 2017 there is a limited amount of non-residential development coming forward. In terms of sites with full permission granted there are only currently 3 sites scheduled for development over the near future (Table 3). It is anticipated that a number of additional sites will come forward as the Local Plan approaches adoption, but in its absence there is little further detail available that is of use to this study.

Table 3: NTC Non-residential development

Area	Site Name	GIA (m2)	Site modelled Gas Consum kWh (CIBSE Guide F)	Site modelled Elec Consum kWh (CIBSE Guide F)
Silverlink retail	Unit 1	4,830	937,020.00	1,144,710.00
	Unit 2	1,672	324,368.00	396,264.00
	Unit 3	1,672	324,368.00	396,264.00
	Unit 4	1,672	324,368.00	396,264.00
Killingworth retail	Lidl	2470	494,000.00	2,260,050.00
longbenton retail	Aldi	1,592	318,400.00	1,456,680.00

4.0 Recap on Clusters identified during Heat Mapping and further analysis

Following on from the Macro-level borough-wide analysis undertaken at the heat mapping stage (NTC Heat Mapping report: EMDH-HM:V1.1 2016) a further look at the individual point-data or building level data is necessary to confirm that the clusters identified during heat mapping remain relevant.

The map below provides an overview of the six clusters previously identified. Only non-residential demand has been assessed on the basis that residential demand is unlikely to act as an anchor to kick-start a district heating network in the way that a close geographic groupings of high demand non-residential consumers might.

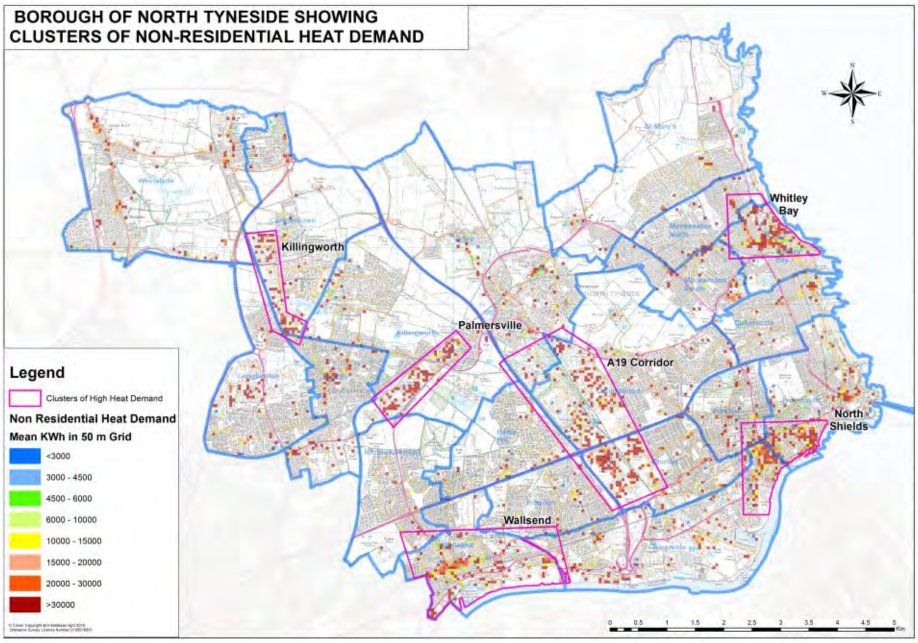


Figure 5: Clusters of non-residential heat demand density in North Tyneside

Table 4: Key Statistics from Cluster level analysis

Cluster	Cluster size (m2)	Heat Demand (kWh)	CO2 (Tonnes p/a)	Overall density (kWh/m2)
A19 Corridor	4,280,195	157,999,207	29,143	36.91
Killingworth	895,451	27,418,646	5,057	30.62
North Shields	1,441,465	33,210,692	6,126	23.04
Palmersville	996,050	20,287,053	3,742	20.37
Wallsend	3,031,996	30,408,774	5,609	10.03
Whitley Bay	1,155,754	24,682,483	4,553	21.36

Table 5: Demand density of building types within identified clusters

	Building Type density kWh/m2									
Cluster	**Commercial Offices**	**Education**	**Health**	**Hotels**	**Industrial**	**Other**	**Recreational**	**Transport**	**Retail**	**Govt. Buildings**
A19 Corridor	9.92	0.05	0.39	1.07	13.04	0.01	0.09	8.78	7.62	0.06
Killingworth	2.56	0.68	0.11	0.22	28.41	0.04	0.20	10.66	5.28	0.78
North Shields	3.40	0.25	0.78	2.92	3.91	0.98	1.60	0.50	7.02	1.68
Palmersville	0.29	0.00	0.00	0.06	7.28	0.02	0.74	6.01	5.97	0.00
Wallsend	0.86	0.95	0.40	0.37	2.13	0.15	0.78	0.73	2.85	0.81
Whitley Bay	1.70	0.40	0.70	6.70	0.36	0.57	2.27	0.11	8.33	0.22

Tables 4 and 5 provide an overview of the key statistics for the six clusters identified, for each cluster the overall heat demand has been calculated and the demand density derived using the measurement of the cluster area. Annual CO2 emissions have also been derived using approved carbon conversion factors.

Analysis of the heat demand density suggests that the A19 Corridor and Killingworth cluster are clear candidates for further exploration with demand densities of 36.91 kWh/m2 and 30.62 kWh/m2 respectively, followed by the North Shields cluster with a density of 23.04 kWh/m2. Both the Palmersville and Whitley Bay clusters are fairly close to the North Shields cluster in terms of demand density, whereas the Wallsend cluster has significantly lower density than the other clusters.

There are a number of other location specific factors to consider at the cluster level, and as such each cluster has been individually assessed on its own merits over the following sections.

4.1 A19 Cluster

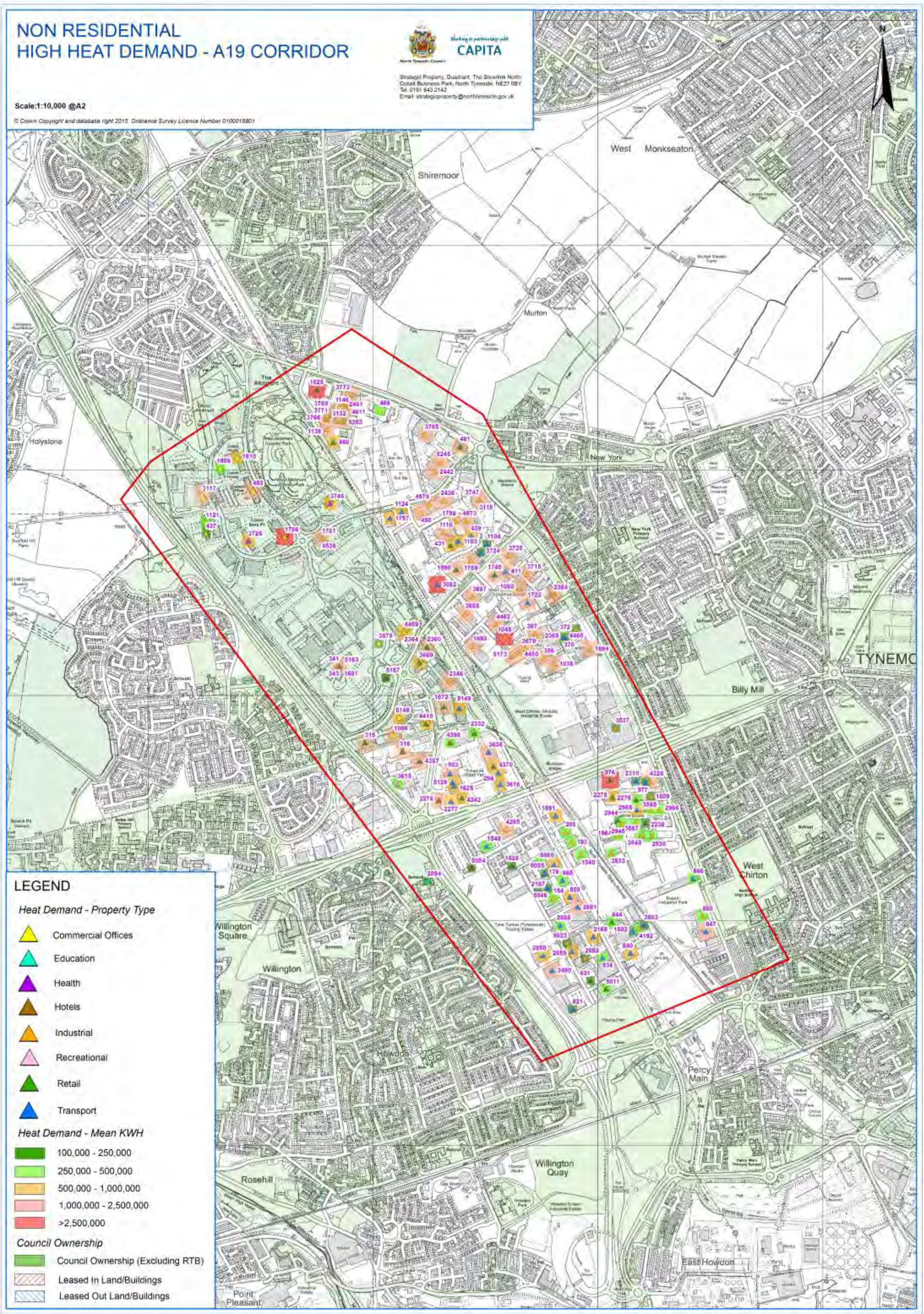


Figure 6: Non Residential High Heat Demand - A19 Corridor

With the highest overall load and density, the A19 cluster (figure 6) covers the largest geographical area of all the clusters identified, and it is also strategically placed towards the centre of the borough, which is worth consideration in terms of future growth potential for a larger scale network.

The A19 cluster is constrained to the west by the A19 which is a major traffic artery for the borough, another major traffic route, the Coast Road (A1058), dissects the cluster to the South, although there is a vehicle underpass which links the Silver-link retail park to the North of the Coast Road to the Tyne Tunnel Trading Estate to the South. With the Highest CO2 emissions of the six areas this cluster also offers the highest CO2 abatement potential. Whilst there is no residential demand within the cluster, it is surrounded by areas of high residential demand to the North and East as well as areas of medium to high residential demand to the West.

A further key location factor is that the cluster is situated adjacent to the Murton Gap housing development site. Whilst the planning detail is yet to be finalised for this site the addition of residential demand to what is predominantly an industrial and commercial cluster load could be beneficial in terms of viability.

Potential NTC anchor buildings within the cluster include the two Quadrant buildings which comprise the Council's head office towards the Northern end of the cluster within the Cobalt Business Park. Surrounding these buildings are two other similar large public sector office buildings occupied by the Northumbria NHS Trust and the Job Centre, adjacent to the NHS site are two large office buildings which provide the regional headquarters for Procter and Gamble. To the very North of the cluster there is a large hotel with a wet leisure facility which is anecdotally understood to have a very high occupancy rate in comparison to other hotels of a similar size/offer. Towards the North East of the cluster is a concentration of smaller light-industrial sites, some with medium sized loads, however caution should be exercised here given potential inaccuracies within the Centre for Sustainable Energy (CSE) dataset. As was discovered during the Heat Mapping Stage, the CSE dataset relies heavily on modelled heat demand derived from benchmarks driven by valuation office measurements (many of which might include measurements for external, unheated space). On this basis, attentions at this stage have been focussed on known NTC operational building loads, and large external buildings have only been included where measurements can be accurately checked using Display Energy Certificate (DEC), Energy Performance Certificate (EPC) data (where available), or Geographic Information System (GIS) measurement.

In terms of potential constraints, it needs to be clarified that the cobalt office buildings are most likely to be leased on long term (20 year+) agreements from institutional landlords. This is certainly the case for the two Quadrant office buildings and for the Proctor and Gamble buildings. Whilst the length of the lease is not necessarily restrictive, under the terms of this type of lease major capital works can only be undertaken with the consent of the landlord. In common with most other new-build offices, all of these buildings are serviced by roof-top plant-rooms (to minimise the loss of lettable ground-floor space). Whilst this shouldn't present any real physical constraint (subject to adequate riser space within each building), this could involve significant additional cost in terms of connection costs, and could present an additional layer of considerable complexity when designing a network around these potential anchor buildings.

As the land ownership key on the previous map identifies, a significant constraint in the Cobalt Park area at the northern end of the cluster is the shortage of land availability. Whilst all of this land sits within NTC ownership, the land immediately surrounding the potential anchor buildings is leased out to the business park developer Highbridge on a 125 year lease. Whilst the estate roads and footpaths will be adopted and access to install heating mains can be achieved, finding a suitable location for an energy centre could be a considerable challenge. It is highly unlikely that any of these sites will be willing to surrender valuable car parking space, and the only remaining non-leased NTC owned land in close proximity is the West Allotment Country Park which is subject to open space restrictions.

The A19 cluster is the closest cluster geographically to the source of potential waste heat identified at the Northumbria Water Ltd. (NWL) Howdon treatment plant to the South of the area, and whilst a final decision has yet to be made, the council are also considering a site to the South of the A19 cluster for its new depot location, which is in reasonable proximity to the Howdon site.

Within a distance of approximately 2km from the proposed depot site are a cluster of council buildings which offer good anchor potential including three primary schools, a mixed-use children's centre, and a dry leisure centre. To the South of this cluster a handful of larger external leisure buildings including a bowling alley, a wet leisure centre, a large indoor 5-aside football centre, and a small discount hotel serving the ferry port. There is a good level of NTC land ownership within the immediate area to aid network routing, and a number of landscaped verges and green-space areas offer good soft-dig opportunities to keep infrastructure costs down.

Whilst it would not be economically viable initially to link the two A19 clusters identified, this could technically be achieved via the embankment to a railway line which runs from the north to the south of the cluster and is currently not heavily used. Although the capital requirement could be considerable, this extension would make the network accessible to both the Tyne tunnel trading estate, and the Silver-link retail park, and as such, this could present a longer-term network growth opportunity

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4.2 Killingworth Cluster

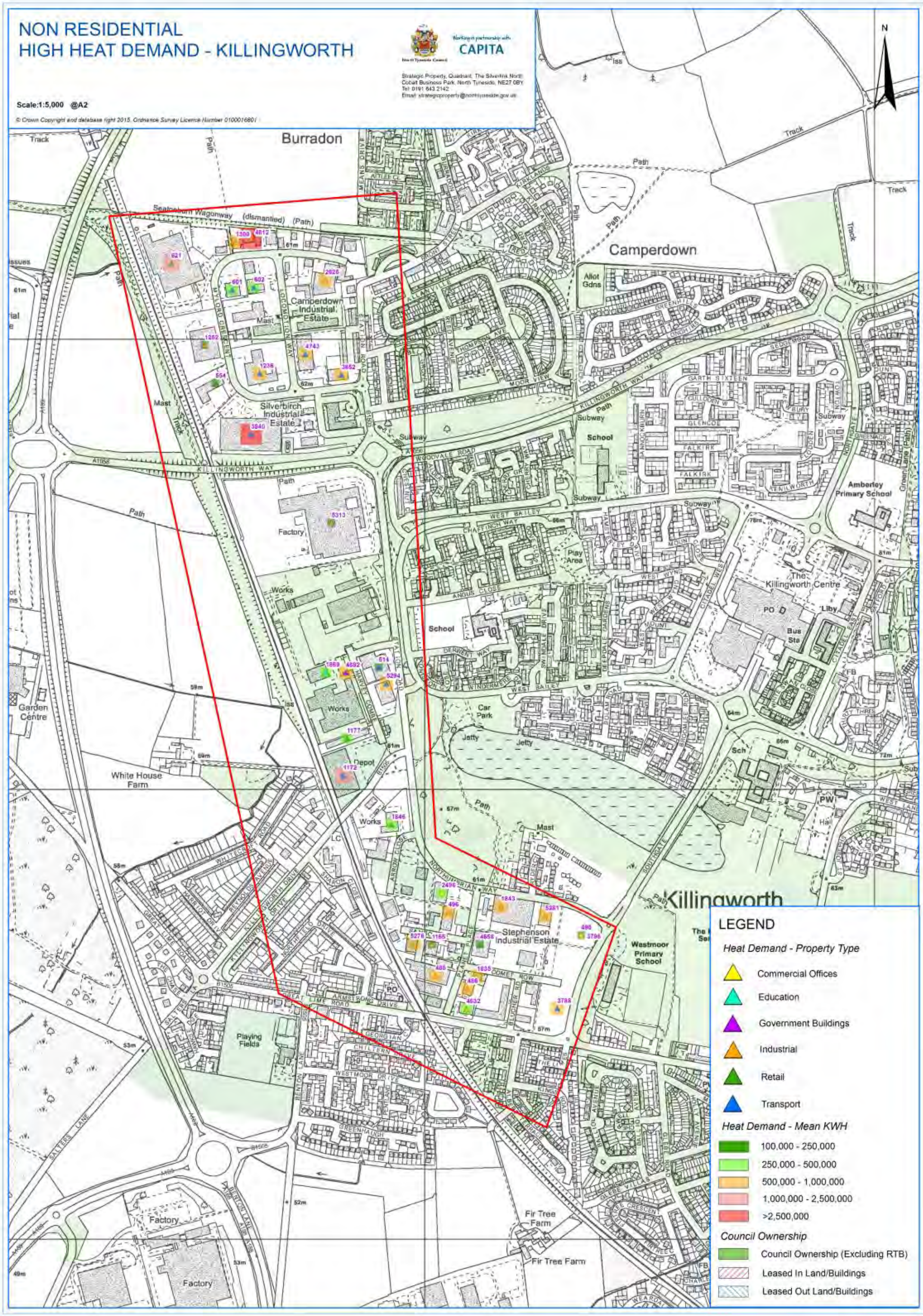

Figure 7: Non Residential Heat Demand - Killingworth

With the second highest overall density the Killingworth cluster (figure 7) is actually one of the smallest clusters in terms of overall size at 895,451m2. In theory, the high density in comparison to the small geographical size is a positive factor in a network context on the basis that the capital costs will be lower for a network covering less distance.

When the heat demand for the Killingworth cluster is examined at the point data level the high demand density identified during the heat mapping phase appears to be a misleading anomaly resulting from the smaller cluster size. As the map opposite demonstrates, when the data is filtered for sites above a 100,000 kWh deminimis annual consumption (below which the site would not be considered to have significant demand to act as a network anchor) there appear to be few sites that would qualify as potential anchors.

Towards the southern end of the cluster are a handful of medium demand industrial sites, with two larger demand sites to the very north of the cluster, again caution should be exercised here given potential inaccuracies within the CSE dataset. The challenges around working with multiple external stakeholders to secure long-term commitment to network proposals must also be taken into account.

On this basis if the focus is shifted west of the identified cluster a number of potential NTC anchor buildings are available including a wet leisure centre (Hadrian Leisure), a large customer service centre and office with a library (The White Swan Centre), a large Morrison's supermarket and covered shopping arcade, and a large secondary school adjacent to the leisure centre (George Stephenson High). There are also two smaller primary schools to the northern (Amberley Primary), and southern (Westmoor Primary) extents of the anchor buildings identified.

There are relatively few physical constraints within this cluster with good NTC land ownership in terms of potential network routing.

In terms of network development opportunities there are areas of fairly dense residential demand surrounding both the identified cluster and the proposed town centre focus which could provide future extension opportunities once an initial network is in place. Future residential connections would certainly improve the financial profile of the network, as provided there is sufficient system capacity the demand profiles of residential properties would be complimentary. However, given the risk around individual residential connections it is not advisable to include this potential demand within the initial feasibility modelling.

4.3 North Shields Cluster

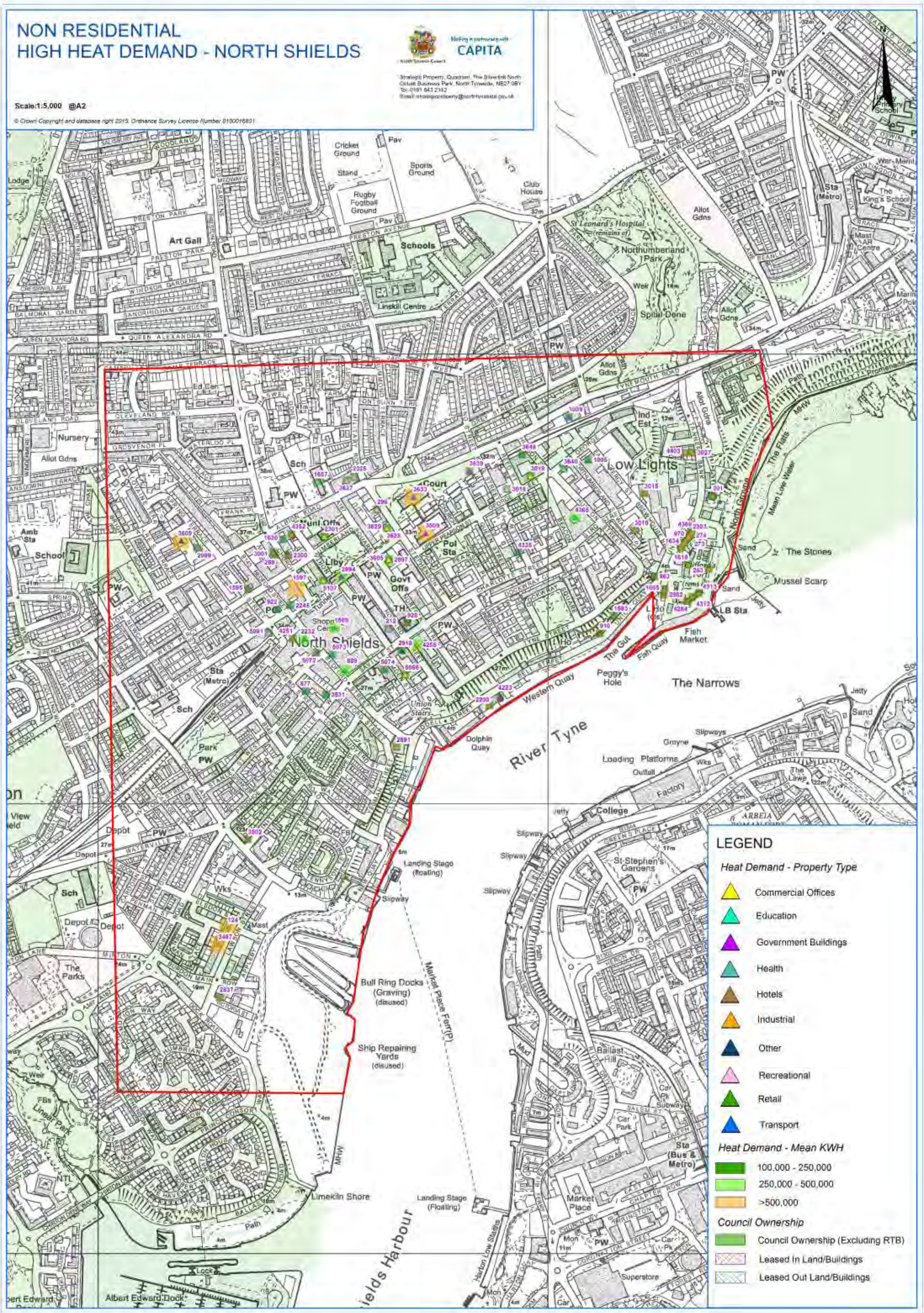

Figure 8: Non Residential High Heat Demand - North Shields

The North Shields cluster (figure 8) has the second highest overall heat demand, but due to its larger size at 1,441,465m2 its density is considerably lower than the A19 and Killingworth clusters at 23.04 kWh/m2, although given its higher consumption/demand its CO_2 abatement potential is higher than that of the Killingworth cluster at 6,126 tonnes/pa.

In terms of constraints this is one of the more densely developed areas within the borough with lower NTC landownership, as such network capital costs are likely to be higher given the higher intensity of existing utilities crossing potential network routes and associated higher dig costs.

The clusters location in relation to the river Tyne is theoretically an opportunity in terms of potential river-sourced heat, however there are considerable topographical/physical challenges associated with this given the steepness of the river banks. On this basis it is advised that river sourced heat opportunities are only explored if the capital infrastructure costs of any network proposals are easily met by the level of demand from reliable anchor buildings. Without this demand the higher capital and operational costs involved in following this approach are unlikely to warrant detailed analysis.

As the map opposite demonstrates, when the point data is examined with smaller demand sites filtered out to identify potential anchor buildings, there are only a handful of sites with medium demand which offer good potential. There is a geographic clustering of these sites around the town centre which includes a large NTC Customer Service Centre/central library as well as the district Magistrates court and adjoining Police station. To the east is an NTC mixed use building, with a Primary school (Christ Church C of E Primary) and church to the north, and a large mixed use YMCA building to the west.

In terms of future development and extension options there is medium to high residential heat demand within the cluster itself along with higher residential demand to the North of the cluster and medium to high residential demand to the South. Once the network is in-place, the potential for future residential connection would most-likely benefit the networks financial performance.

4.4 Wallsend Cluster

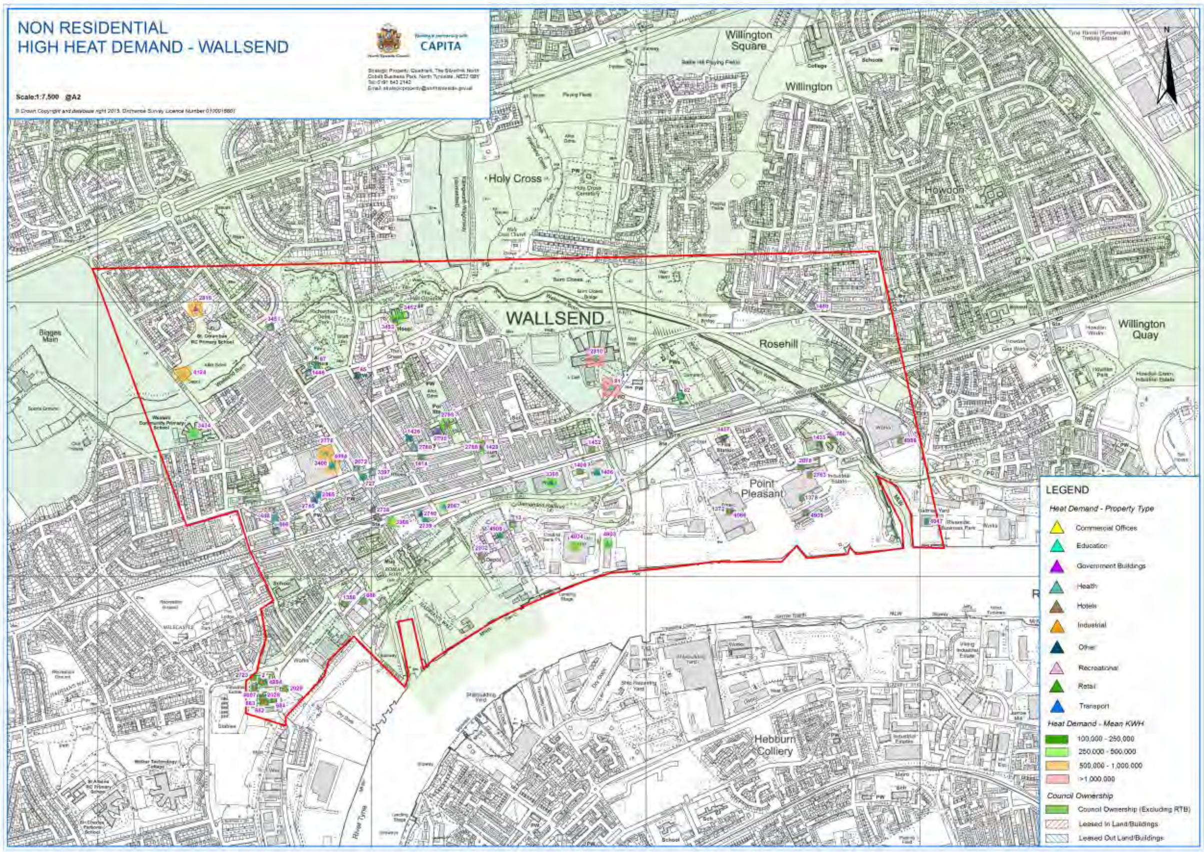

Figure 9: Non Residential High Heat Demand - Wallsend

The Wallsend cluster (figure 9) has the lowest overall density of all the clusters identified and, whilst it has the third highest load, its geographical size, at 3,031,996m2, dilutes the overall demand density of the cluster as a whole.

As the map above demonstrates this dense residential character and established town centre location, with lower NTC landownership, is likely to have an adverse impact with network capital costs likely to be higher than less dense areas. Potential sites for an energy centre location within the town centre appear constrained by the lack of NTC owned land, although there is land availability towards the eastern end of the cluster.

Heat demand within the cluster is mostly residential with predominantly medium demand and some areas of medium to high demand to the North of the cluster. With the non-residential demand filtered, a limited number of potential anchors remain.

There are a number of smaller industrial sites towards the South of the cluster along the Northern bank of the River Tyne, but beyond this there are limited opportunities for anchor loads across the cluster as a whole. In theory this location in relation to the River Tyne, in terms of potential river-sourced heat, could present an opportunity for a smaller scale network serving a small number of industrial along the North bank, but given the higher capital and operational costs associated with water source heat technologies, it is unlikely that there would be sufficient demand to support this. Further to this there are no NTC buildings in the immediate vicinity which could under-pin a network proposal.

To the eastern end of the cluster there is a large modern secondary school (Burnside College) and an adjacent wet leisure centre (Hadrian leisure) which could provide reasonable anchors for a smaller network. Across the road to the east is a primary school (Wallsend C of E Primary), with another primary (Richardson Dees Primary) school along the high street to the west. Further along the high street to the west is the town's main shopping centre with an adjoining building occupied by NTC's Wallsend Customer Service Centre and Library. As is evident from the map overleaf, Soft-dig opportunities are limited, and it is assumed that network mains would have to follow the busy high street in order to connect these potential anchors via the shortest route.

In terms of potential future growth there is significant surrounding residential load, but as described previously it would not be advisable to include this potential load within the initial techno-economic analysis.

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4.5 Palmersville Cluster

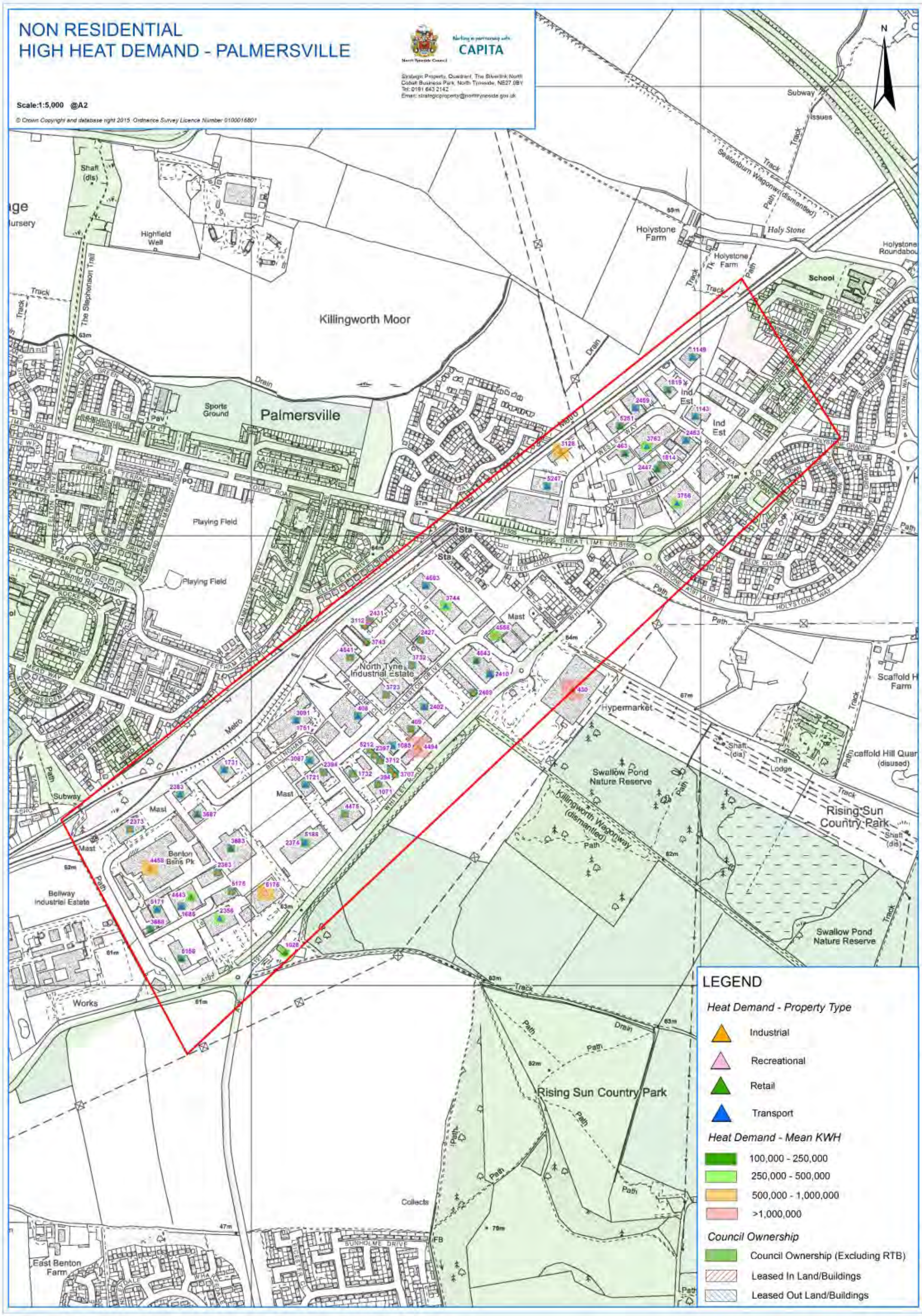

Figure 10: Non Residential High Heat Demand - Palmersville

The Palmersville cluster (figure 10) has a reasonable level of density as a result of its overall heat demand in relation to its smaller geographical size, but its CO2 abatement potential is lowest of all the clusters at 3,742 tonnes/pa. There is medium residential demand to the West and the East of the cluster. In terms of geography the cluster is fairly strategically located as it could potentially link the A19 and Killingworth clusters providing potential for future network growth, although this factor in isolation would not warrant the development of a network.

When the heat demand for the Palmersville cluster is examined at the point data level the demand density identified during the heat mapping phase appears to be misleading. This may be the result of a concentration of a large number of smaller consumption sites within a small cluster size. As the map opposite demonstrates, when the data is filtered for sites above a 100,000 kWh deminimis annual consumption (below which the site would not be considered to have significant demand to act as a network anchor) there appear to be few sites that would qualify as potential anchors.

Further to this there are no NTC buildings within the cluster which provide viable anchor opportunities. Further investigation identifies the Rising Sun countryside visitors centre located to the east of the cluster (figure 11), however, as the map below demonstrates this site is land-locked in terms of ownership and as such locating an energy centre on this site to serve the cluster may not be feasible.

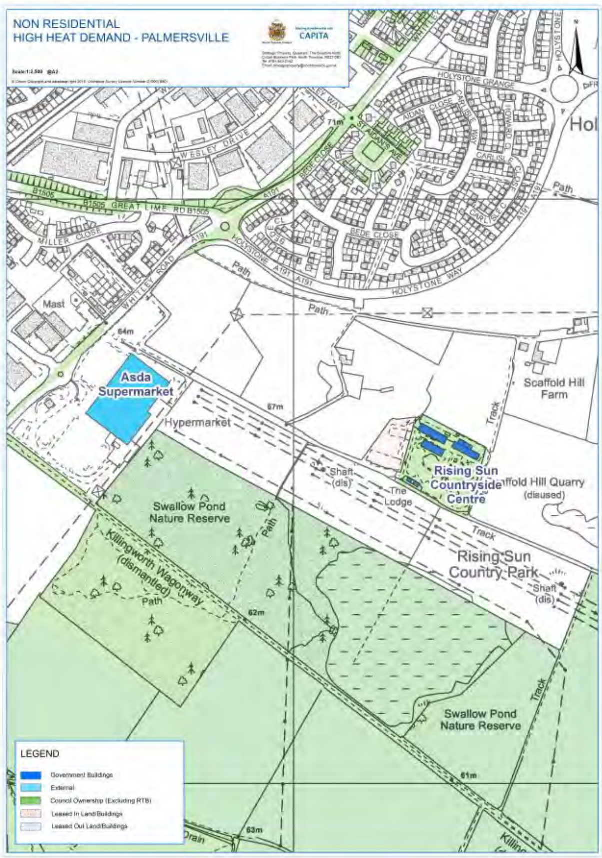

Figure 11: Non Residential High Heat Demand - Palmersville (2)

Apart from the lack of potential NTC buildings potential, potential external anchor buildings are also limited. A large Asda superstore sits within the centre of the cluster, but beyond this there are only four sites within the adjacent industrial estate with above medium consumption.

Given the lack of any NTC anchor buildings within the proposal area, and the level of risk associated with a network proposal relying purely on external private sector anchor buildings, it is recommended that the Palmersville cluster is discounted from the study and that no further analysis is undertaken on the basis that there is no realistically viable opportunity here.

As an alternative it is recommended that attentions are focussed instead on the second potential cluster/opportunity that has been identified towards the southern end of the A19 Cluster (A19 South).

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4.6 Whitely Bay Cluster

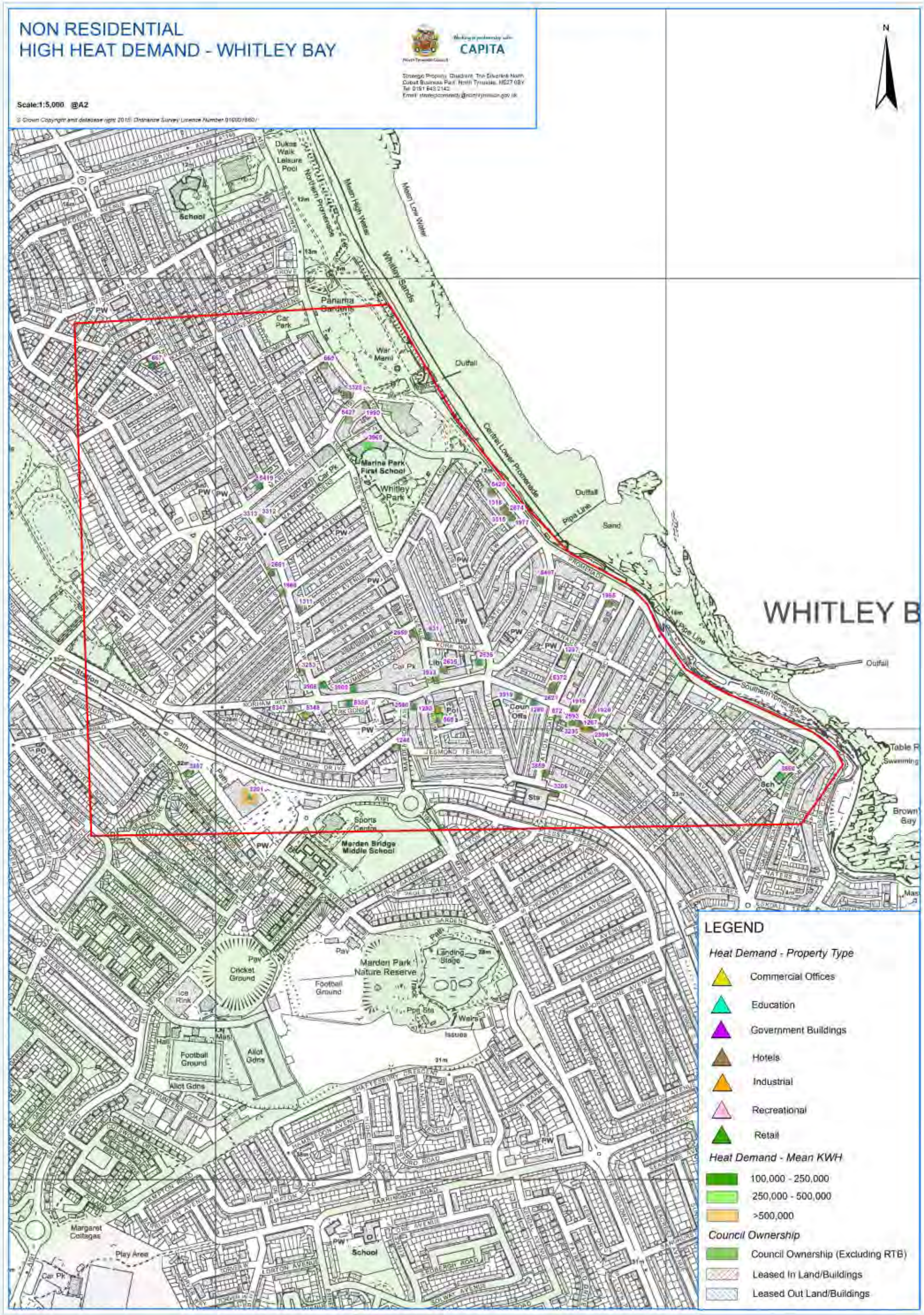

Figure 12: Non Residential High Heat Demand - Whitley Bay

With an overall demand density similar to the North Shields cluster the Whitley Bay cluster (figure 12) has a smaller geographical size, and a lower overall heat demand, with the second lowest CO2 abatement potential of 4,553 tonnes per annum. Whilst there is high residential demand density throughout the cluster Whitley Bay is not a recognised area of fuel poverty within the borough.

In terms of potential NTC anchors there is a wet leisure centre with an adjacent modern primary school outside of the cluster to the far North of the opposite map. Other than surrounding residential demand, there would be little potential for further growth for a network serving this site. There is another modern primary school towards the centre of the cluster, and beyond this there are a number of small to medium sized hotels and smaller retail units within the town centre, although generally there is a lack of individual sites of considerable scale.

If the focus is shifted towards the south there is a potential opportunity on the southern edge of the cluster which includes a dry leisure centre which shares the same site as a large middle school (Marden Bridge), a medium-sized Morrison's supermarket across the road from the school, and a large indoor ice rink further up the road. There is a vacant site next to the school within NTC ownership which would provide a suitable location for an energy centre

In terms of constraints Whitley Bay is also one of the more densely developed areas within the borough with lower NTC landownership so network capital costs are likely to be higher than less dense areas. There is a good level of NTC landownership surrounding the potential sites identified and all can be accessed via NTC owned land.

In terms of future growth potential there is limited potential in terms of large commercial sites, and as such, future growth potential would be limited to residential connections to individual dwellings, further to this Whitely Bay is the most isolated of all the clusters identified and as such the potential for future interconnection with other network proposals is low.

5.0 Low Carbon & Renewable District Heating Technologies

District heating networks provide the infrastructure to deliver heat to consumers efficiently and economically, many of the existing large-scale Northern European networks extend many kilometres beyond their heat generating plant serving heat customers via hundreds of kilometres of district heating mains. The span of networks can be boosted by adding heat sources along the way and existing heat generating equipment can be linked up to networks and thermal stores to provide further flexibility.

Heat can be supplied directly to conventional wet heating systems, or transferred indirectly via a heat exchanger maintaining separation of the two wet systems. Using this indirect technique district heating can be retro-fitted to existing building plumbing circuits avoiding the significant cost of internal replacement. A pre-assembled, packaged, unit known as a hydraulic interface unit (HIU) can be installed within the building connected to the heating main via a metered control valve. Heat exchanging equipment can be provided to an individual building or to a number of buildings via a substation depending on the system design. The heating system within the building is no different to a traditional system offering the same level of control and metering.

One of the most important aspects of these networks is that they don't discriminate in terms of heating source. The integration of diverse energy sources means that district heating customers do not depend on a single source of supply, which helps to guarantee reliability, continuity of service, and can introduce competition into the heat supply chain. District networks can also balance the supply and generation of heat across location and time as demand shifts throughout the day between residential and commercial customers, a heating network can provide for this shifting demand whilst maximising the operation of the plant.

It is this inherent flexibility which provides the opportunity to integrate and optimise emerging renewable technologies into the energy mix. No two district heating systems are the same, each system requires a bespoke solution which will be purpose designed and engineered to meet the scheme's unique intricacies. As a result, there are a range of different district heating technologies which support numerous different distribution configurations. Table 6 provides a summary of the various technologies covered in this section.

5.1 Waste Heat

By far the most efficient source of heat for a heating network is the capture of heat already generated via a primary process and the redistribution of that heat giving it a secondary use thereby maximising the benefit achieved from the CO2 which has been emitted. Low grade or waste heat which is at a temperature lower than that useful to industrial processes (typically below 90˚C), such as the heat rejected from power stations as a by-product of power generation, or waste heat produced via large-scale chemical processing is ideal for this application, subject to both its quantity and proximity to the district heating proposal. As a rule of thumb a source of 2MW of heat within reasonably close proximity is considered to be the lower limit for viability.

Whilst there are no power stations or large scale chemical processing installations within the North Tyneside Administrative area, there is an indicative source of approximately 2MW of heat from the Northumbrian Water Ltd. (NWL) sewage treatment works at Howdon which is within roughly 1km of the A19 South network cluster. The viability of the recovery of this heat was explored as part of the initial Master-Planning report submission but discounted due to non-viability, the analysis is provided in appendix 3.

5.2 Combined Heat and Power

In a Combined Heat and Power plant (CHP) the heat which is produced as a by-product of the generation of electricity is captured to be used locally, or distributed via a highly insulated 'heat main' for use throughout a heating network. The level of sophistication of CHP technologies means plants can exceed 80% efficiency at point of use, compared to traditional centralised power stations with the most efficient combined cycle gas turbine (CCGT) achieving 52% efficiency, and the less efficient coal fired plant achieving around 38% efficiency (CHPA, 2010). CHP plants are generally sited close to demand to meet local energy needs including heat, power, and more recently cooling via absorption cooling involving heat exchanging technologies. The local siting of CHP plants avoids further energy losses of approximately 7% which are incurred through the transmission and distribution of electricity via the National Grid and local distribution networks (CHPA, 2010).

5.2.1 Gas-fired Combined Heat and Power

Gas-fired CHP is by far the most common heat generating technology used in UK district heating systems, and whilst it is not a zero-carbon technology it is widely recognised as a lower carbon alternative to traditional centralised energy production and supply as a result of its ability to achieve the same ends via a more efficient process.

Gas-fired CHP is both a mature and cost effective technology with a well-developed supply chain throughout the UK. Although there are a number of different technical permutations in terms of CHP unit design, units deployed in smaller district heating systems invariably consist of an electrical generator/alternator driven by a gas powered combustion engine with heat recovered via multiple heat exchangers located in the engine jacket and oil cooling circuit with a further heat exchanger located in the engine exhaust manifold.

CHP units can be supplied in various different capacities in terms of both electrical and thermal output, and can be supplied as a packaged unit to be retrofitted to existing plant-rooms (subject to available space) and building heating distribution systems. The majority of current CHP units are also offered as containerised solutions which can be externally located where internal plant room space is restricted. All of these factors contribute to the value and flexibility of gas-fired CHP as a district heating solution.

5.2.2 Biomass Combined Heat and Power

Biomass CHP units operate on either a steam generation or gasification basis. Steam systems use solid biomass fuel to raise high-pressure steam to drive a turbine to generate power, like all steam technologies there are considerable economies/efficiencies of scale. Small scale biomass combustion (below 10MW) are considerably constrained by lower electrical output efficiency (often less than 20%), which is critical in a small network scenario where the value of the power generated can be as much as twice the value of the heat. Gasification systems break down solid biomass fuel into a form of synthetic gas which, when combined with oxygen under high pressure, produces a combustible gas which is used to drive a turbine. Again there are considerable issues of scale here, and whilst there are smaller gasification units available the technology is generally not considered commercially viable, with only a handful of systems currently being trialled in the UK.

As an emerging technology, early indications suggest that Biomass CHP only starts to become viable above 5MWe output. This size of unit is the smallest available commercially viable biomass CHP unit based on steam turbine technology. Other technologies (e.g. gasification, Organic Rankine Cycle and Stirling engines) which may have the potential at this scale or below are currently not commercially robust enough to be considered. This study therefore will only consider the option of biomass boilers, not Biomass CHP.

5.2.3 Biofuel Combined Heat and Power

CHP units are also available that can utilise liquid biomass, known as bio-fuels, which are considered to be low or even zero carbon fuels depending on the proportion of fossil fuel to bio-fuel oil content. As a liquid, bio-fuels are easier to deliver and store than solid biomass.

Under the current Renewable Heat incentive (RHI) programme, there is no financial incentive for bio-fuels used within the non-domestic market, and whilst financial incentives were available for the electricity generated under the Renewables Obligation programme, this support is set to cease from April 2016. Based on previous assessment we have found that a bio-fuel CHP will not provide a return on the investment without income from the Renewables Obligation.

Even with these standards, significant public uncertainty exists over the use of bio-fuels considering the lifecycle carbon content and their sustainability of production especially in overseas markets. Choosing a bio-fuel CHP is therefore considered a risky option as the financial viability will rely on a long term secure supply of OFGEM approved bio-fuels that meet stringent sustainability criteria. Furthermore, with the EU and UK Government target to increase the bio-fuel content of transport fuels under the Renewable Transport Fuel Obligation (RTFO) the costs of bio-fuel are susceptible to the transport fuel cost rises.

5.3 Energy from Waste

A number of the older district heating systems within the UK, such as the Byker system in Newcastle, and the systems serving the city centres of Nottingham and Sheffield, were established as a result of the construction of waste incinerators as part of municipal waste management strategies of the time. As policy directions have changed over the last 2-3 decades incineration has fallen out of favour, leading to the closure of many of the UK's local incinerators. (Please see Section 7.4 for narrative on recent developments in this regard).

There is currently no waste incineration facility within the borough of North Tyneside and whilst the Authority are currently considering options prior to the renewal of its waste management strategy it is understood that although it is unlikely that NTC would lead on the development of a local energy from waste incinerator plant, should a third party operator express interest in providing a facility, this could present an additional heat source for consideration.

5.4 Anaerobic Digestion

Anaerobic digestion (AD) is both a technology and technique used in the production of synthetic gas which can then be used under combustion to produce power (and heat by proxy) via a modified gas turbine. During the digestion process gas is released as a by-product of the decomposition of organic matter, which when combined with oxygen under high-pressure produces a combustible gas.

Almost any organic material can be used as a feedstock for a digestion unit, including food waste, agricultural and animal waste, arboricultural waste, and even purpose grown energy crops. As with Biomass technologies scale is a critical issue with significant volumes of feedstock required to produce even smaller capacity generation equipment. With the smallest commercially viable unit available at 1MWe scale requiring 40,000 tonnes per year of food waste, based on the national average food waste of 0.29 tonnes per household, the total annual food waste feedstock of 26,000 tonnes from approximately 90,000 North Tyneside households would not be sufficient to support this.

There is only one known anaerobic digestion plant within the North Tyneside borough. The Advanced AD pant at the NWL Howdon treatment works is known to produce around 130 MWh of biomethane per day. Whilst this would present a fantastic opportunity for a district heating proposal this synthetic gas is already spoken for under an existing gas network entry agreement with Northern Gas Networks, and following the registration of the scheme with the renewable heat incentive following commissioning in December 2014 NWL are receiving a tariff rate of around 7.6 pence per kWh of gas fed into the grid. This is more than double the rate at which gas can be purchased on a medium to large scale commercial contract and as such this would not be a viable option for any network proposal.

5.5 Large Scale Heat Pumps

Whilst all variants of heat pump operate on essentially the same technology, via a reverse refrigeration cycle whereby heat at ambient temperatures is heavily compressed resulting the temperature being raised, the means by which the input heat is collected varies between the different applications. Both Air source and Ground source heat pumps are not suitable for district heating applications as the size of the heat collectors required, either surface coils for air source, or ground loops for ground source, to service the heat demand of multiple buildings is just not feasible to produce the volume of heat required. A ground source heat pump for example requires approximately 50m2 of trenched ground loop (slinky coils) to deliver 1kW of heating potential (heat pump with an assumed seasonal CoP of 2.5), on this basis the smaller back-up boiler requirement for the smallest of the six systems identified (Wallsend, 260 kWt) would need 3.2 acres, or 1.3 hectares of land to provide approximately 17% of the system's overall annual heat output.

Water source technologies do have potential where there is a sufficient body of flowing water available which can be directed through a chamber of heat exchangers suitably sized as to extract sufficient heat. In the UK an extraction licence, issued by the Environment Agency, is required for any extraction rate above 20m3/day equivalent to approximately 4kW. As identified during the heat mapping phase the water source heat potential layer of the National heat map suggests that the River Tyne has a potential heat capacity of 500-950kW.

The critical factor with all heat pump technologies is the seasonal adjusted coefficient of performance (CoPs). A heat pumps coefficient of performance highlights the performance ratio of input energy to output energy. With all heat pumps the input energy is the electrical power which is used to drive the compressor which raises the input temperature to the required output level. Whilst many heat pump manufacturers will claim CoP's of 3.0 and above, when this is adjusted for seasonality, as pumps have to work much harder (consuming more power) over the winter season to maintain the heat output, the seasonal adjusted CoP is often much closer to 2.0, or 2kWh Heat produced from 1kWh Electricity. The critical issue here is that when 1kWh of electricity costs around 12p and 1 kWh of heat is worth around 5.5p it is not cost effective to produce heat this way. This is perhaps an overly simplified example but it does highlight the important considerations when specifying heat pump technologies. Accurate and detailed design is critical for heat pump systems, especially at district heating scale.

Where system proposals are within feasible reach of water sourced heat resources their suitability within the technology mix will be assessed.

5.6 Large Scale Solar Thermal

Whilst Solar Thermal heat collectors provide an ideal source of heating in certain applications at the individual building level (predominantly swimming pools and leisure centres), their specification within the UK district heating context is constrained by a number of technical and financial challenges. In financial terms the amount, and subsequent cost, of land required to accommodate a solar thermal collector array large enough to meet the heat demands of even a small network would render most business cases non-viable. Further to financial challenges there are a number of key technical constraints such as the need to raise the output temperature of the solar collector (around 45°C based on UK seasonal averaged performance) to a higher temperature more suitable to the operation of existing building heating systems (around 80°C), the additional energy required to achieve this often outweighs the initial benefits of solar thermal as a technology option. In addition to the technical constraints in the district heating context, the recent DECC RHi consultation has announced plans to remove tariff support for Solar Thermal under the RHi framework.

Whilst there have been some successes with large scale solar thermal networks in other European countries the feasibility challenges within the UK district heating context are underlined by the fact that there are currently no solar thermal heated networks either in existence, or in the pipeline, in the UK.

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5.7 Technology Evaluation

Table 6: Technology Evaluation Summary

Technology	Suitability	Justification
Waste Heat	Potentially Suitable	Although potential sources are limited there is an opportunity for waste heat from the NWL treatment site to the south of the borough.
Gas-fired CHP	Potentially Suitable	Gas-fired CHP is a mature, scalable, and cost-effective technology which can achieve significant CO2 savings in a network scenario.
Biomass CHP	Not Suitable	The scale at which Biomass CHP becomes feasible is beyond any of the network proposals examined within this report
Biomass Boilers	Potentially Suitable	Suitable as a technology to provide back-up heat during seasonal demand peaks, would not be implemented as the primary heat generator as opportunity to sell more lucrative power would be lost
Biofuel CHP	Not Suitable	The scale at which Biofuel CHP becomes feasible is beyond any of the network proposals examined within this report
Energy from Waste	Not Suitable	There are no Energy from Waste facilities in the area
Anaerobic Digestion	Not Suitable	Although there is an Existing AD facility within the borough this is subject to an existing gas grid entry agreement and there is currently no additional capacity to support a network proposal. Initial calculations indicate that there is not sufficient feedstock generated by waste within the borough to support the development of a further AD facility
Large Scale Heat-pumps	Potentially Suitable	Potentially feasible as a heating technology in this context but economics are tight and specifications have to be considered on a case-by-case basis.
Solar Thermal	Not Suitable	Not suitable due to a combination of technical and financial constraints highlighted in the technology analysis

6.0 System Proposals

6.1 Network Modelling approach

To assist the Council in evaluating the district heating system opportunities identified following the heat mapping analysis, a Microsoft Excel based desktop model has been created to assist in the techno-economic analysis of system options. A simplified overview of the model is provided here, full detail of the model and identification and explanation of the assumptions it uses are provided in appendix 1.

6.1.1 Building Demand and plant Sizing

The model takes the annual gas consumption for the potential anchor buildings identified and applies a boiler efficiency correction to convert the buildings gas consumption into actual heat demand. The demand is then separated into heating demand and domestic hot water (DHW) demand based on the building type. The building type is then used to derive a monthly demand profile for each building. For NTC operational buildings the monthly profile is based on actual consumption in conjunction with the current programming schedules used in NTC's central building management system (BMS).

In the case of non-NTC buildings where it was not possible to obtain actual consumption data via engagement attempts both at the Heat Mapping and again at the Master-Planning stage the relevant CIBSE TM46 and CIBSE Guide F energy consumption benchmarks signposted in the DECC Heat Networks Code of Practice document (HNCoP) were applied to the Valuation Office Agency's measurement records to derive annual gas & electric consumption. Where available, EPC certificates were accessed via the DCLG/Landmark online portal and the reported consumption detail used in favour of modelled data for those buildings. The source of data used for each building is identified in each proposal section. Monthly and seasonal consumption profiles for non-NTC buildings have been derived from the BMS programming profiles used in NTC buildings with similar operational and occupational profiles (in keeping with HNCoP best practice, ref. 2.1).

There is relatively little air-conditioning deployed throughout the NTC operational estate, apart from the more recent customer service buildings, leisure centres, and some PFI schools, the vast majority of buildings have not had cooling plant retro-fitted. Whilst there is no actual consumption data for cooling loads within the NTC operational estate as cooling equipment is not sub-metered within the estate (nor logged on an ongoing basis on the central BMS system), cooling loads have been derived using CIBSE benchmarks where available (cooling benchmarks are not available for all CIBSE building categories).

Once the seasonal profile for each building for both heating and DHW has been extrapolated from the annual consumption the aggregate monthly demand profile across the cluster can be identified. Once derived the monthly demand profile across the cluster will inform a number of key metrics which are used to determine system specifications.

When an assumed (standard) 17hr per day CHP cycle is applied to the monthly heat demand across the cluster a monthly CHP size requirement is identified. Two different approaches can then be applied to the CHP sizing requirement.

Sizing the CHP to meet the base-load heat demand of the cluster will ensure that the CHP is not oversized, and that its efficient operation is optimised by minimising non-running time to ensure continuous power generation.

6.1.2 Thermal Storage

Sizing the CHP above base-load heat demand using a thermal store as a buffer to offset the effect of the seasonal drop in demand across warmer summer months is a further strategy to enhance operation. By specifying a thermal store and sizing the CHP unit to meet demand above base-load, a larger CHP unit can be specified. The higher volume of power generated by a larger unit will improve system economics, especially in a private wire system where the power generated is significantly more valuable than the heat produced.

The capital cost of thermal storage is considerable at around £843/m3 (DECC 2015) and it might not make economic sense to specify a store large enough to take the entirety of the summer excess heat generation. Space requirements for storage are also significant with around 22m3 required to store 1MWh of heat (Tyndall Centre 2013). Depending on the seasonality of demand from the different buildings within the cluster, even a small system serving only a handful of buildings could require thousands of cubic meters of storage to buffer the excess summer heat produced if the CHP unit was sized to meet higher than average demand. With associated costs running up to several million pounds, before land costs are taken into account, this approach could be prohibitive. On this basis a certain point between the base-load and average CHP capacity will prove most cost effective in terms of the storage economics, this approach has been trialled within the model for the various system proposals as part of the techno-economic analysis.

The inherent storage capacity of the network transmission mains has been factored in to each model scenario, as the highly insulated transmission mains essentially provide thermal storage. This capacity is identified in the report supplement document and is expressed in terms of m3 volume, MWh storage potential, and in terms of system run hours.

Beyond the inherent network capacity additional thermal storage capacity has been modelled for each proposal for both modular and base-load CHP configurations. The capacity of the additional storage is sized on the basis of extending daily system run-time by 3-5 hrs to assess the beneficial impact on systems revenues.

For all system approaches there will be a seasonal excess in heat demand which cannot be met by the CHP output. It is not viable to size a CHP unit for maximum demand in the way that heating systems are traditionally over-sized as it is not cost effective to modulate the output of individual CHP units. The back-up boiler capacity requirement is derived from the monthly excess heat requirement with an assumed 12hr per day boiler operating cycle factored in. Options for both traditional gas and biomass top-up boilers have been modelled, as well as large scale water source heat pumps where feasible.

6.1.3 Third Party Accommodation potential

Options for 3rd party back-up have also been modelled for each proposal on the basis that cost efficiencies would be achieved if the back-up capacity requirement was met by the existing heating plant within the various cluster buildings rather than the energy centre itself. Whilst this would require further detailed examination at the feasibility stage on a building by building basis cost efficiencies around energy centre and plant costs along with savings on operational overheads have been factored into the model. The reduction in associated heat sales has also been factored in to account for the reduction in revenues resulting from the lower volume of network delivered heat.

Options for potential third party hosting of the energy centre itself, thereby avoiding the cost of a dedicated energy centre, have been considered for each proposal. Site visits/survey undertaken however confirmed that none of the identified NTC operational buildings could offer sufficient space to accommodate this (table 7).

Table 7: NTC Operational Buildings: Available Plant Room Space

Building/Site	Plant Room Location	Approx. Available Space (m2)	Identified Constraints
Amberley Primary School	Ground Floor	2	Insufficient space
George Stephenson High School	Multiple ground Floor locations	12	Insufficient space
Lakeside Centre	Ground Floor	no space / access only	Limited space/access
White Swan Centre	Basement	3	Limited access
Riverside Centre	External Adjoining plant room	no space / access only	Limited access
The Parks	Multiple 1st Floor locations	n/a	Limited access
Riverside Primary School	Ground Floor (x2)	2	Insufficient space
Waterville Primary School	1st Floor (mezanine)	no space / access only	Limited space/access
Central Library	1st Floor	n/a	Limited access
Christ Church C of E Primary School	Basement	5	Limited access
Northumbria Youth Action Ltd / Youth Village	1st Floor	n/a	Limited access
Burnside College	Ground Floor	6	Insufficient space
Hadrian Leisure	Ground Floor	8	Insufficient space
Richardson Dees Primary School	Ground Floor	6	Insufficient space
Wallsend St Peters Primary School	Basement	no space / access only	Limited space/access
Marden Bridge Middle School	Basement	no space / access only	Limited space/access
Marden Bridge Sports Centre	1st Floor	n/a	Limited access

The CIBSE AM12 CHP model has been built into the pre-feasibility model to establish further CHP operational detail based on the model's CHP sizing outputs. This provides detail on how much heat will be generated for sale (adjusted for assumed network losses), and how much power will be generated for sale (adjusted for network parasitic electrical load).

6.1.4 Financial Detail

Table 8: Model Pricing Assumptions

Item	Price (p)	Unit
Electricity Private-wire sale	11.69	kWh
Electricity export	4.5	kWh
Heat Sale	5.2	kWh
Gas purchase	2.53	kWh
Biomass Purchase	4.6	kWh

Modelled system revenues (table 8) are derived using pricing assumptions driven by the CHP outputs for heat and power generation. An assumption of 11.69p per kWh is used for electricity sold by private wire, this is modelled at 95% of the DECC projected price scenario for 2018 (DECC Annex-f price growth assumptions 2013) on the basis that it is not likely that any proposals could be operational prior to 2018. It is assumed that this price will be both competitive against tariff rates at the point of launch, given the 5% reduction, and future-proofed going forward. Comparative export only revenues have been modelled based on an assumed grid export/power purchase price of 4.5p/kWh. A heat sale price of 5.2p/kWh has been assumed based on a comparative 2018 commercial gas unit rate of 3.7p/kWh with an additional uplift for the boiler maintenance & life-cycle replacement saving. This figure is lower than the benchmark mean average figure of 6.43p/kWh identified in DECC's *Assessment of the Costs, Performance, and Characteristics of UK Heat Networks* (2015) document and is assumed to be price-competitive against traditional heating approaches. Individual building standing charges have been derived based on each buildings size, this is in-keeping with current utilities provider methodology, and the disaggregation of standing charges from unit rates is both in-keeping with the approach of current utilities providers, and serves to keep unit rates comparatively low.

The cost of the input fuel required to operate the network is modelled at 2.53p/kWh for gas based on price indications received from independent energy brokers for gas purchase agreements at this volume (this is in-keeping with DECC's 2015 Fossil Fuel Price Assumptions) . Prices for biomass are modelled at 4.6p/kWh based on price indications from biomass suppliers for 20% moisture content biomass pellet supply at this scale.

In the case of biomass and WSHP top-up options the renewable heat incentive (RHi) payments have been modelled based on the current (2016 DECC Consultation) RHi tariff for Biomass systems. The income from these payments are included within the income section of the model to offset the higher capital costs of Biomass heating plant rather than passed straight through to the network customers by discounting the heat sale price.

Operational costs have been modelled using DECC benchmarks (DECC 2015) for network maintenance (including network, HIU, and heat meter maintenance), Bureaux costs (including metering, billing, and revenue collection), and business rates. (Further breakdown of costs identified in appendix 1)

Capital system costs have been drawn from indicative costs provided by CHP and Biomass providers with balance of system (BOS) costs and network infrastructure having been provided by Capita's internal M&E design function based on experience from previous projects. Design parameters for thermal storage requirements have been taken from a 2013 Tyndall Centre publication on thermal storage for district heating systems produced as part of an Engineering and Physical Sciences Research Council Programme, with cost detail drawn from DECC's *Assessment of the Costs, Performance, and Characteristics of UK Heat Networks* (2015)

Each system proposal is modelled for both private wire & grid export income for electricity generated. Top-up heat demand is also modelled for both gas CHP & gas top-up, and biomass boilers to allow the additional capital cost of biomass plant to be assessed.

As the following sections will demonstrate, a number of the biomass systems return favourable financial performance despite the higher capital costs involved when compared with traditional gas CHP & gas top-up technologies. It is important to note that this favourable performance is underpinned by the additional income received via the RHi tariff mechanism, not as a result of a superior technology or system design.

All assumptions used within the model are detailed in appendix 1 for further consideration.

6.1.5 Hydraulic modelling Approach

It is not possible to undertake full hydraulic analysis and modelling at this pre-feasibility stage, due to the lack of available detail for the external buildings within each proposal and the resulting lack of technical design inputs for the network proposals themselves.

As we do not yet have consistent half hourly consumption data for each building it is not possible at this stage to undertake detailed demand profiling for each building to undertake detailed assessment of base-load heat and maximum heat demands. The absence of this detail prevents the assessment of hourly load duration curves as well as delta T and pressure differential analysis required to produce detailed network and plant specifications based on modelled network heat loss. This will be undertaken as part of the detailed technical analysis in subsequent stages.

In the absence of this detail assumptions at this stage based on a standard assumed network flow temperature of 90°C with return at 70°C. This based on traditional heating system requirements for flow at 80°C with upward adjustment to account for network heat loss of 10% (88°C rounded to 90°C). On the basis that each of the system proposals involve retrofit to existing buildings rather than supply to new developments, as there are no new developments in the immediate vicinity of any proposals (or insufficient available detail in the case of the Murton Gap development), it is assumed that there is no value in exploring low temperature heat network options. At the proposed network flow temperature of 90°C with return at 70°C it would be possible to configure a low temperature connection for a new building via the lower 70°C return leg via a HIU with thermal buffering, essentially obtaining a secondary income for heat that has already been sold.

On this basis the prefeasibility modelling has been undertaken using cost and network performance metrics based on an assumed specification of standard 300mm EN253 compliant pre-insulated steel pipe. This specification of pipe is available from a number of UK suppliers in standard 6m, 12m, and 16m lengths, and is commonly used throughout UK district heating applications. The maximum heat capacity of this pipe is around 5.5MW and with the largest capacity network proposal modelled at approximately 2.6MW this ensures there is significant growth potential within all proposals and relatively little risk of mains overloading from future connections. As the detail of the proposals develop at the feasibility stage a proper sizing analysis will be undertaken as part of the network optimisation process.

6.1.6 Financial Analysis

In order to evaluate the economic viability of the district heating network options it is necessary to understand the return on the capital investment associated with each system. When appraising long term capital investment projects, it is necessary to review the scheme over the lifetime of the project. In the case of district network heating systems this is typically 25 and 40 years.

Discount cash flow methods allow cash-flows received at various stages of the project to be compared.

The most common of discounted cash flow methods are:

- Net Present Value (NPV) - assumes a discount factor (DCF) aligned to the cost of borrowing, against which capital investment is evaluated using future cash flows (cost and revenue) over a defined time period. This analysis has used a DCF of 6% in line with the cost of borrowing for public sector capital investment projects. A positive NPV demonstrates that a project is profitable. A negative NPV indicates how much gap funding must be sourced to make the project viable.

- Internal rate of return (IRR) – demonstrates the interest rate at which the net present value of future cash-flows from a project equal zero. If the IRR is below the cost of borrowing it is unlikely to be profitable. A negative IRR value suggests that the sum of post investment cash flows is less than the initial capital investment. IRR works best when future cash flows are positive against an initial capital investment. A negative IRR is somewhat meaningless as a financial assessment and only serve to confuse the reader.

Negative IRR results have therefore been omitted from subsequent financial summary tables.

A sensitivity analysis has been conducted to demonstrate at what DCF the NPV turns negative (not profitable) or positive (profitable).

6.2 A19 North System proposal

Figure 13: A19 North System proposal map

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6.2.1 A19 North System – Anchor Buildings and Energy Centre Location:

Table 9: A19 North Anchor Building Properties

Building	Size m2	Annual Heat demand (MWh)	Annual Power demand (MWh)	Annual Cooling demand (MWh)	Data Source	Comments
Quadrant East (NTC Office)	13,683	1,205	2,836	274	Actual consumption data from NTC EM System	Large Modern office with continuous DHW load, seasonal cooling load, and no heating load in July & August.
Quadrant West (NTC Office)	7,189	436	1,095	144	Actual consumption data from NTC EM System	Large Modern office with continuous DHW load, seasonal cooling load, and no heating load in July & August.
Job Centre Office	9,839	945	2,302	197	Modelled on CIBSE TM46 using EPC & GIS measurement	Large Modern office with continuous DHW load, seasonal cooling load, and no heating load in July & August.
NHS Office	5,235	451	1,225	105	Modelled on CIBSE TM46 using EPC & GIS measurement	Large Modern office with continuous DHW load, seasonal cooling load, and no heating load in July & August.
Village Hotel	8,457	3,890	1,269	846	Modelled on CIBSE TM46 using GIS measurement	Large Modern Hotel with continuous DHW load, seasonal cooling load, and no heating load in July & August.
P&G	16,027	1,923	3,750	321	Modelled on CIBSE TM46 using GIS measurement	Large Modern office with continuous DHW load, seasonal cooling load, and no heating load in July & August.

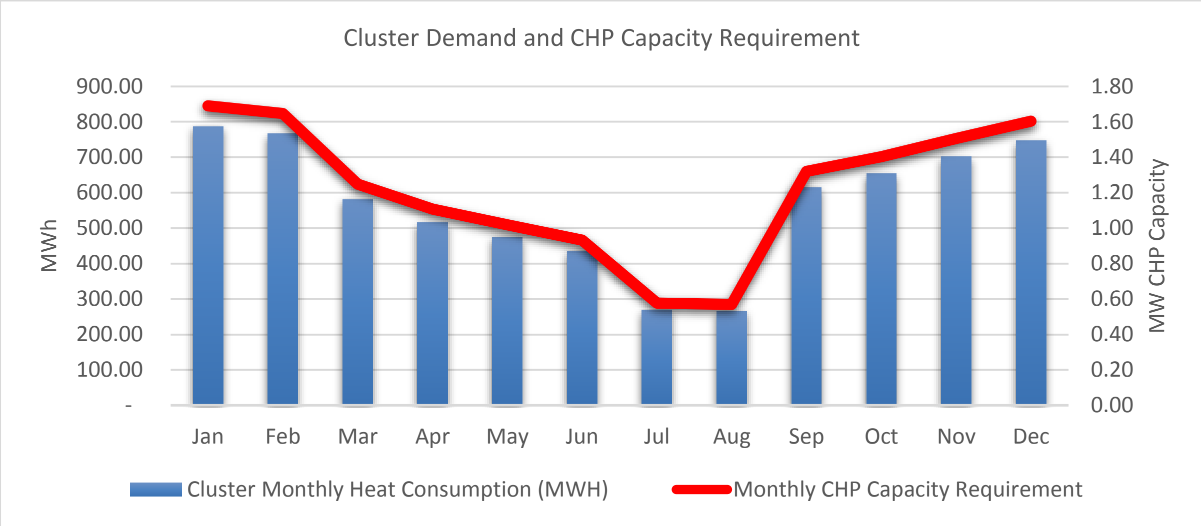

Figure 14: A19 North - Monthly Heat Demand& CHP Capacity Requirement

The A19 North cluster does not offer a great deal in the way of diversity in terms of the buildings identified. With all but one of the buildings demonstrating a standard seasonal office heat demand profile, the smoother demand profile provided by the Village Hotel (with wet leisure centre) helps to smooth the profile of the overall cluster, although the a considerable drop in demand from June to September is noticeable (figure 14). The higher demands are provided by the Hotel, the Proctor & Gamble buildings, and Quadrant East, and, although the Quadrant buildings are leased on a long-term basis by NTC, each of these buildings are non-NTC owned, and as such, the network is dependent on their long-term commitment as anchor buildings (table 9).

Only two of the six buildings within the cluster are NTC operational buildings with actual half hourly consumption data available, with the remaining four buildings reliant on benchmark modelled data. Each of the non-NTC buildings would be significant anchors within the network so further attention at the feasibility stage will be required to test the benchmark outputs.

Figure 15: A19 North - Aerial Satellite View

As identified on the proposal map (Figure 13), whilst all of the land within the immediate vicinity is within NTC ownership, as the map demonstrates the vast majority of this is leased out on a long-term basis (125 years) to the business park's developer Highbridge Properties. This presents a number of land and access constraints as, whilst the land is owned by NTC, a number of legal consents would have to be sought under the terms of the lease. Further to this, and of critical importance, is the ownership of the anchor buildings themselves, which are most -likely to owned by institutional investors and occupied on long-term tenancies. Whilst this does not present an insurmountable constraint in its own right, it would provide an additional level of complexity in securing commitment from the potential anchor buildings.

As Figure 17 indicates, the adjacent Murton Gap development site presents an opportunity for a further phase of development for this system. Although firm proposals for this site are yet to be finalised, a separate energy master-planning initiative specific to this site is currently underway. As identified within the Hydraulic Modelling section there is significant additional heat capacity built into the modelled system mains infrastructure to cater for future network expansion. Within this network specifically, approximately 2.5 MW of additional heat capacity can be accommodated by the mains specified which should be sufficient to facilitate the future interconnection of the two systems subject to the final development plans for the site.

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6.2.2 Energy Centre Location – Justification & Rationalisation

In terms of potential energy centre locations, as both the map (Figure 13) and the satellite image (Figure 15 & 16) identify, the options are clearly limited. The only viable sites with suitable vehicle access lie to the far north of the cluster area in proximity to the Village Hotel. Both of these sites lie within the leased out area and their use would be reliant on the negotiated surrender of the lease covering these sites, which may require a significant inducement payment to the leaseholder.

There is site at the Northern end of the cluster of approximately 900m2 that is not within NTC ownership but is currently un-developed (figure 16). The site could comfortably accommodate the maximum energy centre requirement of 300m2 along with any additional requirement for biomass or thermal storage. Whilst the apparent green-field appearance of the site should be beneficial in terms of development costs, a further check should be undertaken at feasibility stage to ensure the site is not encumbered by any open space or village green constraints. Although the site is not centrally located within the cluster, given the land ownership constraints within the immediate area, this is the only suitable site available within reasonable proximity to the proposed network.

Further assessment of proposed Energy Centre sites; including; Air Quality Assessment, Noise Disturbance Assessment, Visual Impact Assessment, and Planning Risk, will be undertaken at subsequent stages.

Figure 16: A19 North - Aerial Satellite View (2)

Consultation with the NTC Asset Management and NTC Energy Management function have confirmed that the two NTC operational buildings within the cluster are heated by traditional medium temperature wet heating systems operating at approximately 80°C flow with 70°C return. Domestic hot water is supplied by with calorifiers operating at 60°C flow and 50°C return. Further detail on the non-NTC buildings will have to be sought at the feasibility stage however, it is assumed that all buildings are suitable for connection to a district heating network and that none of the buildings identified present insurmountable constraints in terms of the proposal.

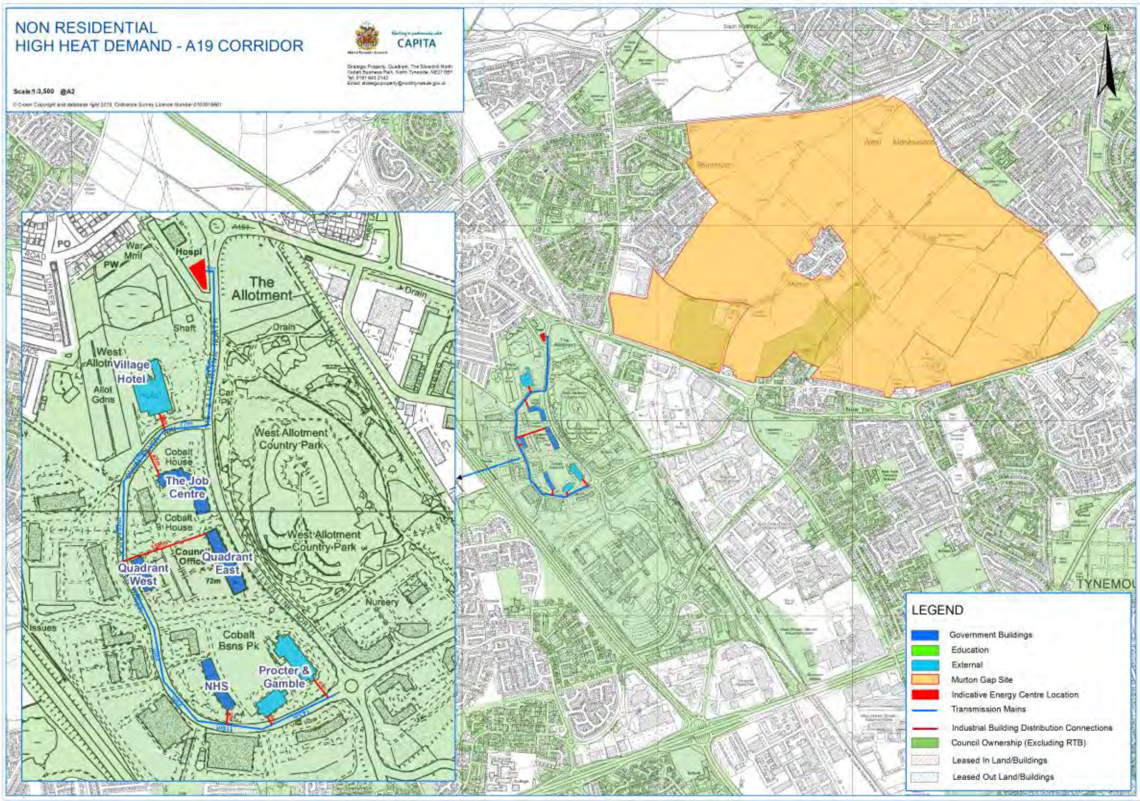

Figure 17: A19 North – System proposal map with Murton Gap development site overlay

6.2.3 System configuration and Technology Options:

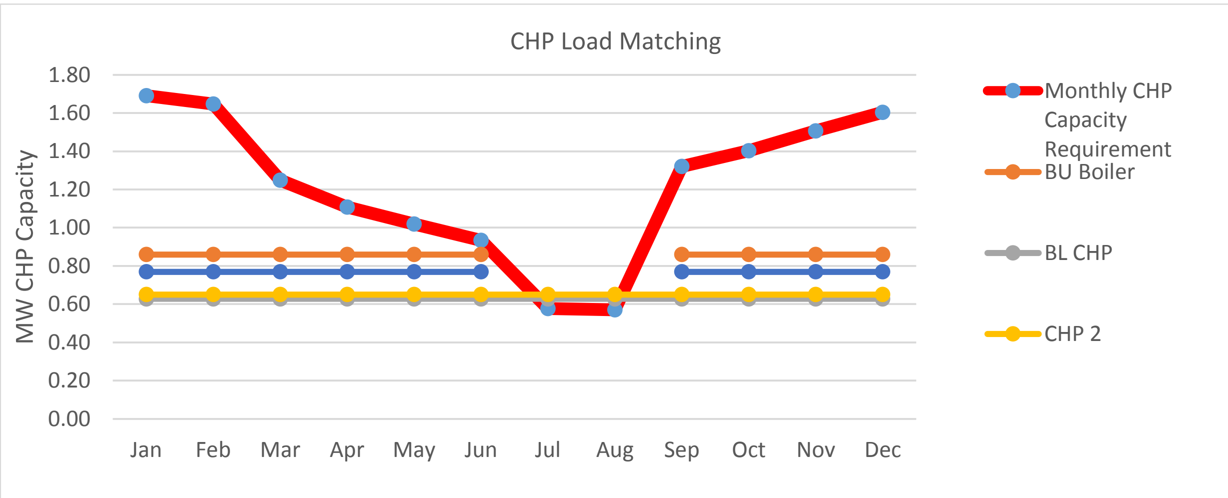

Figure 18: A19 North - Monthly CHP Capacity Requirement & CHP Load Matching

With the lowest monthly heat & DHW demand across the cluster occurring in August (figure 14), the corresponding base-load of 265.5 MWh would dictate a maximum CHP size of 630kWt/490kWe, with a top-up boiler capacity requirement of 1.8 MWt for gas fired boilers, or 1.95 MWt for Biomass boilers (figure 18). On a base-load CHP sizing basis only 47% of the annual heat demand would be served by the CHP unit with the remainder being provided by the back-up boilers.

If a modular CHP approach were adopted a the smaller base-load CHP unit could be supported a larger 650kWt/500kWe CHP unit to provide a combined capacity of 1.28MWt/1MWe which would provide approximately 78% of the annual heat demand and reducing back-up boiler capacity requirement to 0.86MWt for gas fired boilers, or 0.93MWt for Biomass boilers. Further to this the modular CHP approach would generate an additional 1,834 MWh of power for sale.

For both the gas CHP & gas top-up, and biomass top-up system options electricity sale via a Private-wire only, and export only approaches have been modelled to establish the value of the different approaches.

To connect the potential anchor buildings identified, a total 1,214m of transmission mains would be required at a capital cost of £1,194,576 with a further 331m of distribution mains to individual buildings at a cost of £198,600, and an overall cost of 170,675 for building connections.

Total capital costs for the gas CHP & gas top-up network including network infrastructure, plant and energy centre costs comes to £2,408,391. Whereas the total cost for the biomass top-up system comes in at a higher total capital cost of £2,803,494 due to the higher cost of biomass heating plant and ancillary equipment.

With a combined volume of 85.8m3 the network transmission mains provide an inherent storage capacity of approximately 3.9MWh, or the equivalent system run time of 2.1 hours. An additional capacity of 88.31m3 has been specified for the modular CHP thermal storage model providing an additional 4MWh of storage at a cost of £74,443. A slightly smaller vessel has been specified for the single CHP thermal storage model at 83m3 (3.8MWh) at a cost of £69,981

Annual power generation for the larger modular CHP configuration, once adjusted for network parasitic electrical load, provides approximately 4,526MWh. The combined annual electrical consumption of the NTC operational buildings within the cluster is approximately 3,494MWh or around 77% of the total generated power. The combined annual electrical consumption of the non-NTC buildings within the cluster is approximately 8,547MWh, approximately 189% of the generated power. On this basis the assumption that all of the CHP generated power can be sold via private wire can be upheld, although lower system revenues based on electricity sale exclusively at export prices will be assessed in the interests of stress testing the proposals.

Table 10: A19 North - System Cost Summary

System	Network Infrastructure costs (£)	Energy Centre & Plant costs (£)	Potential CO2 abatement (tonnes p/a)	Total costs (£)
Gas CHP & TU	1,563,851	844,540	1,320	**2,408,391**
Gas CHP biomass top-up	1,563,851	1,239643	1,654	**2,803,494**

Table 11: A19 North System Annual Income Profile

System Annual Income profile		
Income Item	**Gas CHP & TU (£)**	**Gas-Biomass (£)**
Energy Sales (Private Wire only)	895,547	895,547
Energy Sales (Export Only)	563,151	563,151
RHI Income	-	77,192
Standing Charge	45,323	45,323
Business rates (Cost not income)	40,962	40,962

6.2.4 Network options – Financial Assessment:

A techno-economic analysis is presented for the Killingworth cluster for the following four technology options:

1. Gas CHP unit using private wire electrical distribution
2. Gas CHP unit with electricity exported to the national grid
3. Gas CHP unit plus biomass heat generation with private wire electrical distribution
4. Gas CHP unit plus biomass heat generation with electricity exported to the national grid

Table 12: A19 North Cluster Summary Table

A19 North Cluster				
		Appraisal (years)	**IRR**	**NPV @ 6%**
Gas CHP Private Wire	Without TS	25	11%	1,156,033
		40	12%	1,811,237
	With TS	25	13%	1,762,337
		40	14%	2,549,075
Gas CHP Export	Without TS	25	-	-2,779,518
		40	-	-2,876,506
	With TS	25	-	-2,955,198
		40	-	-3,070,110
Gas CHP + Bio Private Wire	Without TS	25	11%	1,221,781
		40	12%	1,960,791
	With TS	25	13%	1,711,600
		40	14%	2,532,419
Gas CHP + Bio Export	Without TS	25	-	-2,713,770
		40	-	-2,726,951
	With TS	25	-	-3,005,935
		40	-	-3,086,767

Table 12 provides an overview of the financial performance of the four system options for the A19 North network proposal at an assumed public sector borrowing rate of 6%. As the table identifies, neither of the export based systems return a positive NPV suggesting that they are not viable given the capital investment required.

However, based on a private wire electricity sale approach, both gas CHP & gas top-up and biomass top-up system options would be viable at the 6% target rate. The biomass top-up approach returns a higher NPV over both the 25 and 40 year appraisal periods with a marginally greater IRR value across both periods despite the higher capital costs.

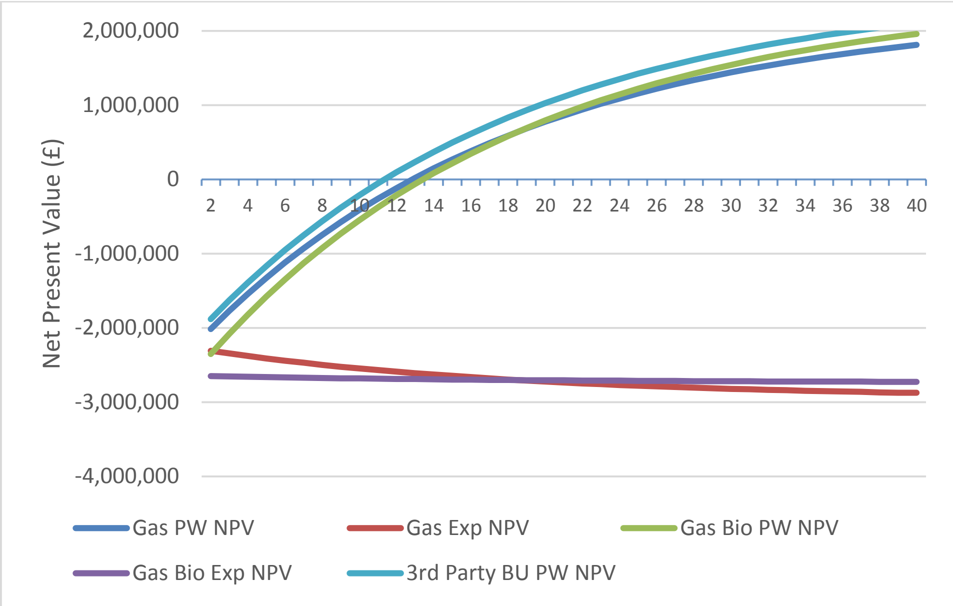

Figure 19: A19 North Cluster – Modular CHP Outline Cost Evaluation (NPV discount rate @ 6%)

As Figure 19 above demonstrates, both modular CHP private wire systems are net positive from year 13 onwards, both systems having repaid the required capital outlay at this point. This suggests that the network would operate profitably from this stage onwards. The third party backup system is quicker to pay back due to the lower upfront capital requirement resulting in a positive NPV being achieved from year 11 onwards.

In the case of the gas CHP & gas top-up and the biomass top-up system under a grid-export approach a positive NPV is never obtained over the appraisal period of a maximum of 40 years. This suggests that considerable additional gap funding (to reduce capital expenditure) would be required in order to make this approach viable.

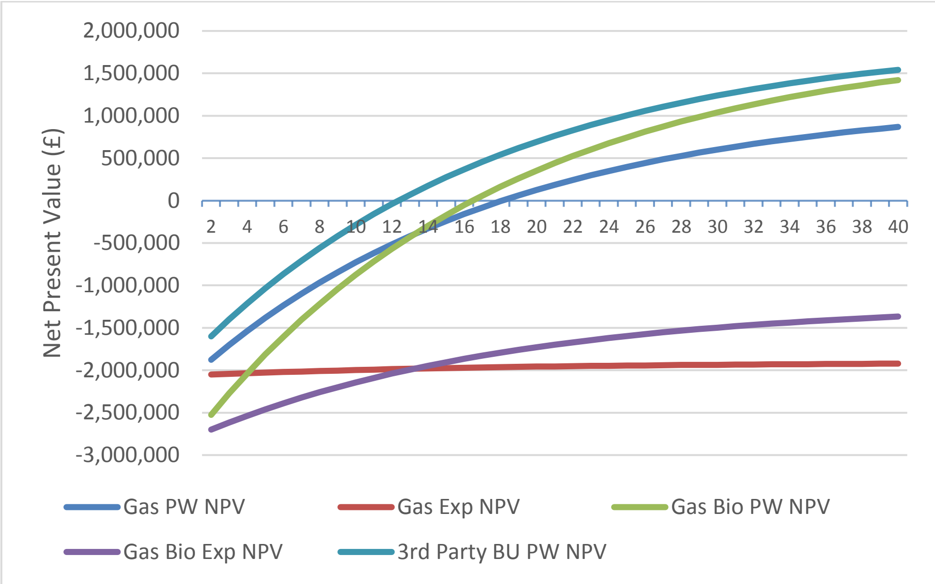

Figure 20: A19 North Cluster – Base Load CHP Outline Cost Evaluation (NPV discount rate @ 6%)

The Base load CHP performance highlighted in Figure 20 above identifies that positive NPV values are not achieved for private wire configurations until year 16 onwards in the case of the Gas-Biomass system, and year 17 onwards in the case of the Gas CHP & gas top-up system. This suggests that the network would operate profitably from this stage onwards. The third party backup system is quicker to pay back resulting in a positive NPV being achieved from year 12 onwards.

In the case of the gas CHP & gas top-up and the Biomass top-up system under a grid-export approach a positive NPV is never obtained over the appraisal period of a maximum of 40 years. Whilst the Biomass top-up system demonstrates stronger performance, considerable gap funding would be required in order to make this approach viable.

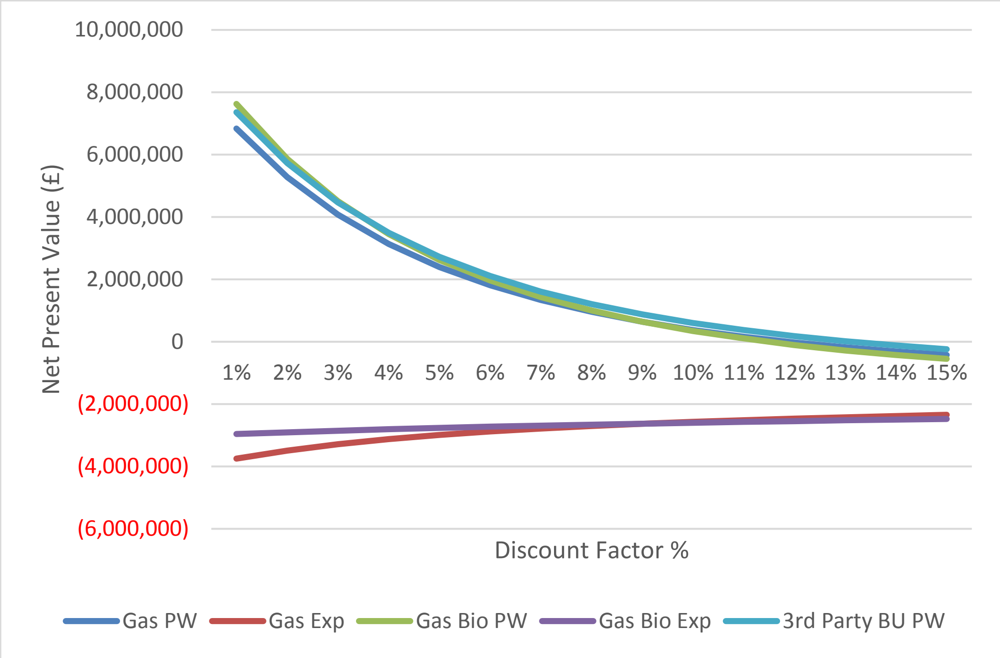

Figure 21: A19 North Cluster – Dual CHP NPV DCF Sensitivity Analysis

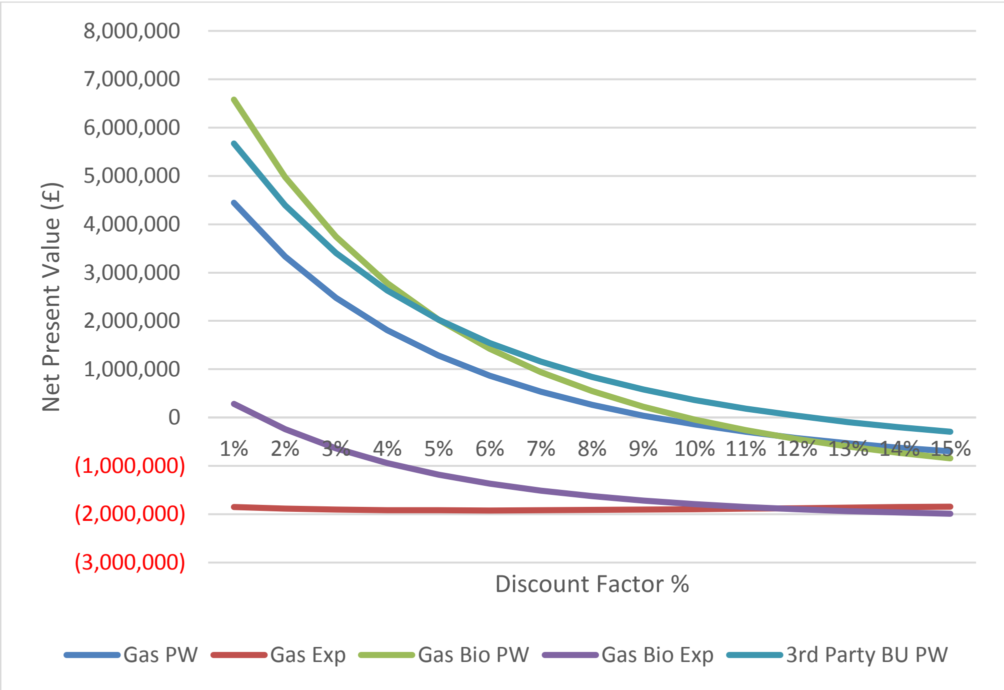

Figure 22: A19 North Cluster – Base Load CHP NPV DCF Sensitivity Analysis

Figure 21 and 22 above demonstrate the change in NPV for a given discount factor. The DCF essentially represents the cost of borrowing. It is therefore possible to ascertain the viability of the system across a range of borrowing rates.

As noted previously, public sector funded projects are typically financed at a cost of borrowing of around 6%. Conversely, it is unlikely that private sector could be secured from the open market at a borrowing rate of less than 10%.

As Figure 21 demonstrates, both modular CHP private wire proposals return a positive NPV at a 10% discount factor, suggesting that both of these proposals are robust enough to secure private sector funding, although neither system under an export approach would attract private finance, nor would they warrant public borrowing support without significant capital offset. In the case of the Base Load CHP approach (Figure 22) the highest discount factor supported by either private wire proposal is approximately 9%.

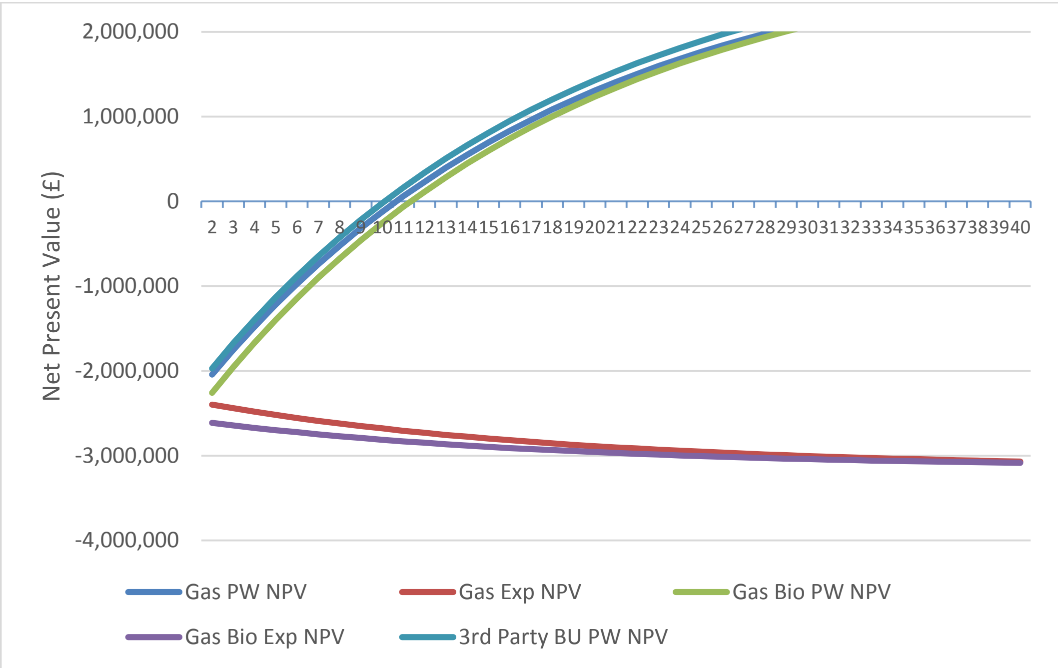

Figure 23: A19 North Cluster Modular CHP with Thermal Store - Outline Cost Evaluation (NPV discount rate @ 6%)

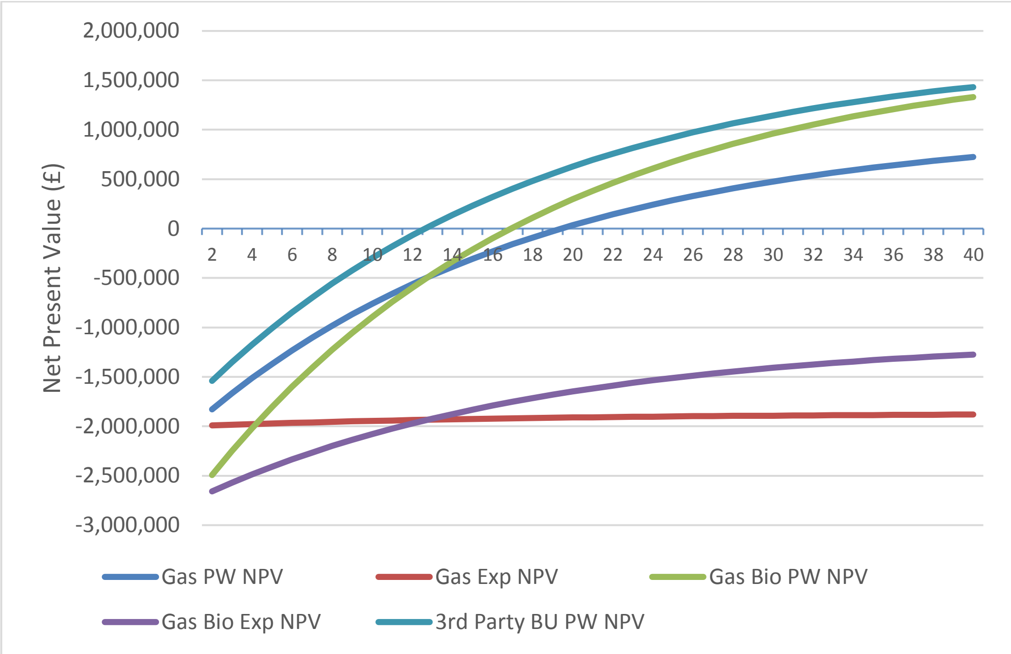

Figure 24: A19 North Cluster Base Load CHP with Thermal Store - Outline Cost Evaluation (NPV discount rate @ 6%)

It is evident from figures 23 and 24 that whilst thermal stores require additional capital investment the improved financial performance can offset the additional capital expenditure required. In the case of the modular CHP private wire systems both proposals generate a positive NPV more quickly than those without thermal storage with the gas CHP & gas top-up system net positive from year 10 onwards (3 years sooner), and the biomass top-up system from year 11 onwards (2 years sooner). In the case of the base load systems however the converse is true with the gas CHP & gas top-up system requiring a further 2 years (year 19), and the biomass top-up system requiring a further year (year 17), to return a positive NPV. This essentially demonstrates how critical the income from electricity sales is to the financial performance of each system. In the case of the base load CHP systems where the greater share of heat is generated by the top-up boilers, and income from electricity sales is limited as a result of the smaller base load CHP unit, the additional capital requirement for the thermal store has a detrimental effect on the financial performance of the system.

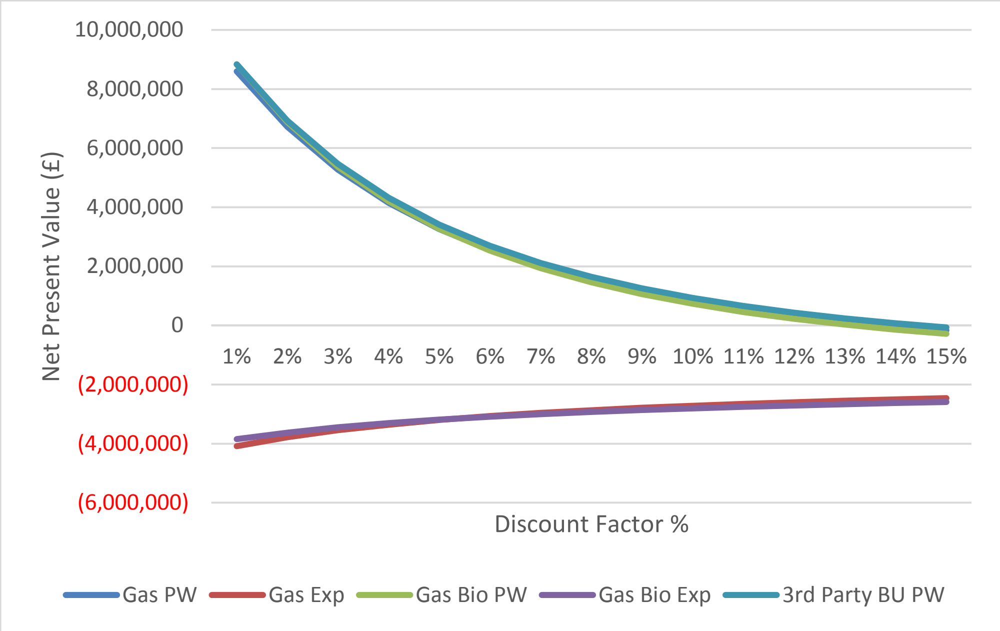

Figure 25: A19 North Cluster Modular CHP with Thermal Store - NPV DCF Sensitivity Analysis

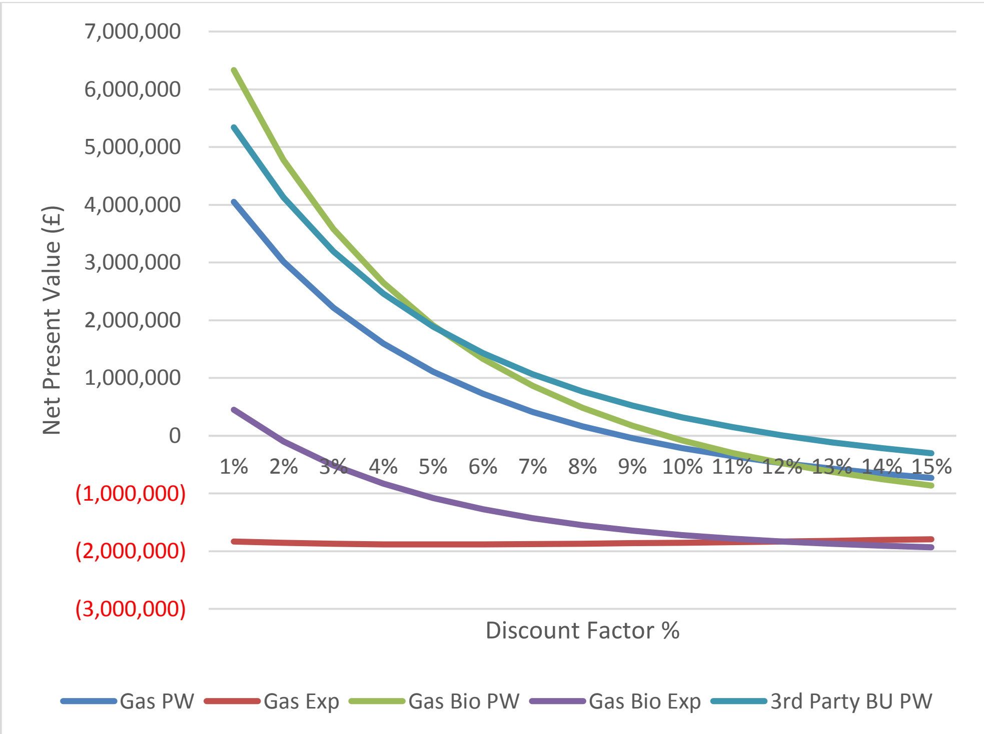

Figure 26: A19 North Cluster Base Load CHP with Thermal Store - NPV DCF Sensitivity Analysis

Further to the NPV analysis figure 25 above demonstrates that for private wire systems, under a modular CHP approach, both thermal storage options meet the threshold requirements to attract private sector financing, as well as providing a healthy return at public borrowing rates. In the case of base load private wire systems public borrowing requirements are easily met for thermal storage options, although performance falls just short of private lending requirements dropping into negative NPV at a discount rate of approximately 9% (figure 26).

6.2.5 Proposal Evaluation – Summary:

In terms of likely network characteristics there is limited load diversity within the demand profile for this cluster, although the heat demand profile is both extended and smoothed to an extent by the Village Hotel and its pool, the office buildings also extend the profile somewhat with a longer 15hr operating day in comparison to many other building types.

The proposal does present significant load risk however as only two of the six buildings are NTC operational buildings, all other buildings are occupied by external organisations therefore the viability of the proposal is dependent on their buy-in.

The two NTC buildings are not owned outright by NTC but are occupied on a long-lease meaning that the landlords consent would be required to connect to the network. The non-NTC external buildings are also likely to be leased so agreement would likely have to be sought from multiple institutional landlords before firm connection commitments can be made. Approximately 23% of the generated power would have to be sold by Private Wire supply to external buildings therefore additional agreements may be required.

The land available to locate the energy centre is limited due to the amount of leased out land (Figure 12). The closest the proposed energy centre can be located to the cluster is approximately 275m away resulting in additional capital cost. Adopted highways can be accessed to locate network mains, although these routes are heavily trafficked during the working day, disruption to traffic flows during the installation phase would have to be closely managed. Further to this the ability to capitalise on soft-dig opportunities could be limited where sites are under institutional landlord ownership as access may not be forthcoming without additional cost.

The financial analysis suggests that the A19 North network proposal is reasonably robust demonstrating a positive NPV across either technology/configuration option under a private wire scenario. In addition to this the financial performance of either private wire option is sufficient to secure both public and private sector funding support achieving positive NPVs at discount rates of up to 10% which introduces considerable financial flexibility in the case of this proposal. Grid export approaches present significant challenges as a result of weaker financial performance requiring in gap funding in the region of £2.7-3.1 m to achieve a positive NPV.

In terms of overall viability, the modelled financial performance of this scheme does indicate that this is a robust proposal, however both the load risk in terms of reliance on connections to non-NTC buildings, and also the reliance on modelled demand detail for those external buildings should not be overlooked.

6.2.6 Potential Phase 2 Network Extension to include Murton Gap Development

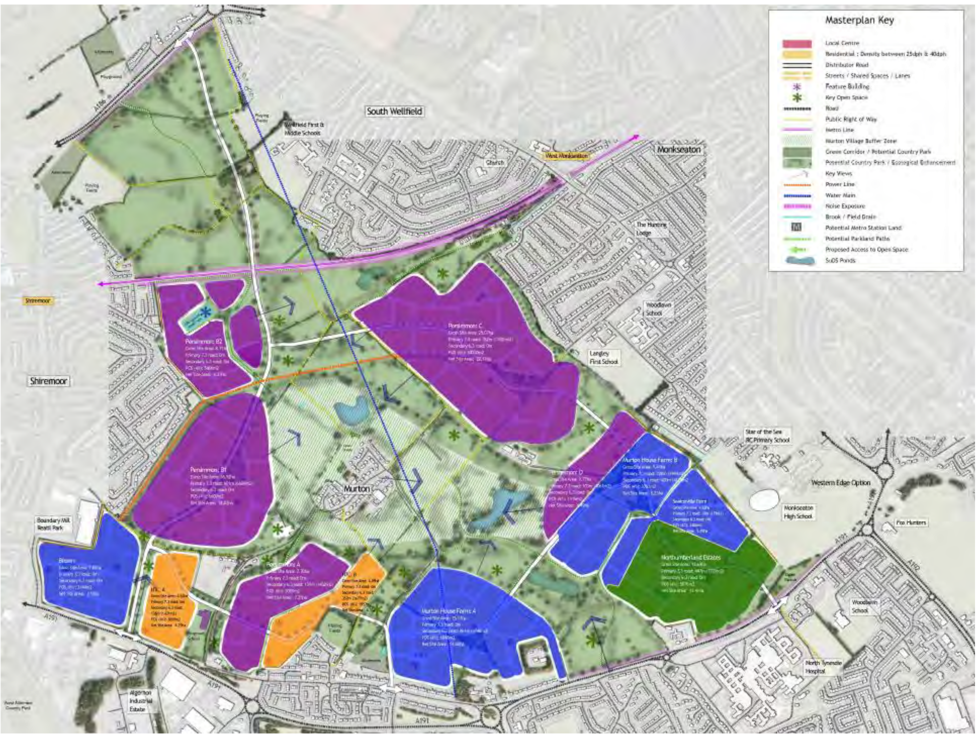

Figure 27: Murton Gap indicative Masterplan

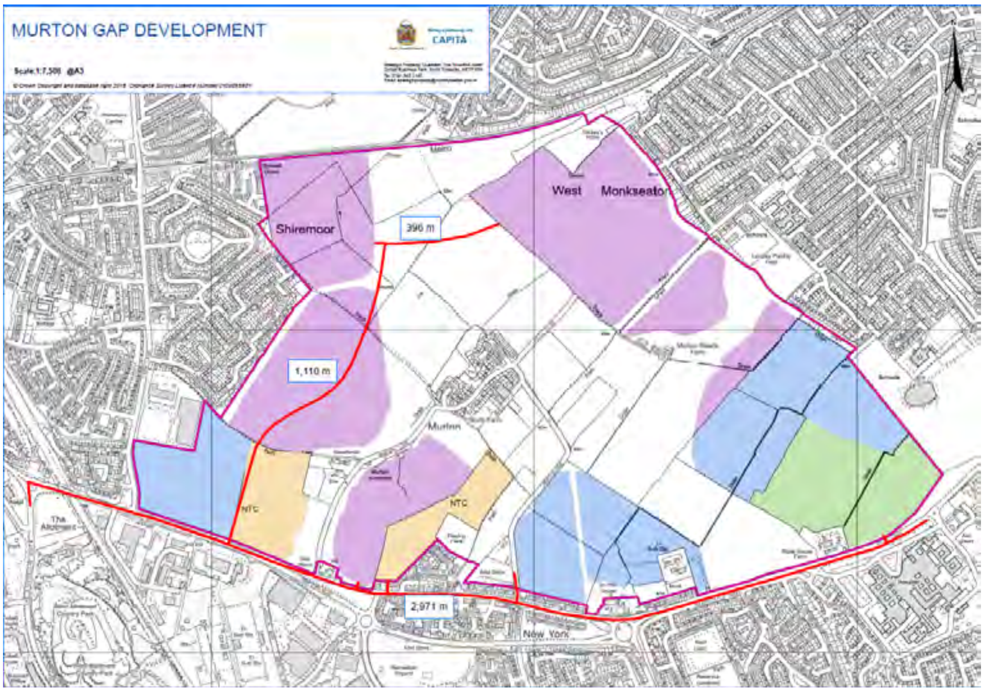

Figure 28: Indicative Murton Gap Network Extension

As the map provided in figure 27 identifies the proposed Murton Gap development lies approximately 500m to the East of the identified first phase of the A19 North network proposal. Current proposals for the development include 3,000 new dwellings of various sizes, approximately 1,204m2 of primary education provision, and 1,000m2 of retail provision. The indicative Masterplan (figure 27) is only illustrative at this stage and no final decision on layout has been reached. As such no final allocation of dwelling numbers has been decided for the various housing development cells shaded pink, blue, and green in figure 28.

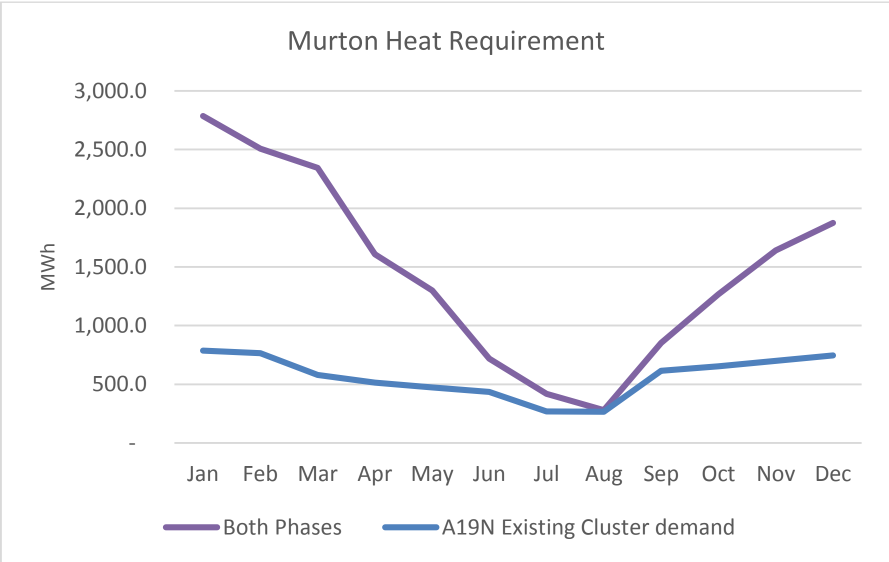

Figure 29: Phase 1&2 Heat Demand

With an additional heat demand of 17,662 MWh per annum the inclusion of the Murton Gap development represents a significant extension to the initial system with an almost five-fold increase in the amount heat delivered annually from 6,827 MWh to 24,449 MWh. To service this additional demand a further 3.4 MWt of CHP capacity would be required along with an additional 4.64 MWt of top-up boiler capacity, bringing the combined thermal capacity of the larger system to approximately 10.2 MWt, roughly a 460% increase over the initial 2.2 MWt combined capacity. The further 2.6 MWe capacity provided would generate approximately 350% more power per annum at 15,515 MWh in comparison to the initial 4,526 MWh per annum.

Table 13: Phase 1&2 Network Detail

Element		Phase 1	Phase 2	Additional	% Increase
Plant	CHP Thermal capacity (MWt)	1.3	4.7	3.4	361
	CHP Electrical capacity (MWt)	990 (kWe)	3.6	2.6	363
	Top-up boiler capacity (MWt)	860 (kWt)	5.5	5.5	639
	MWh annual heat delivered (MWh)	6,827	24,449	17,622	360
	MWh annual power generated (MWh)	4,526	15,515	10,989	343
Network Infrastructure	Transmission Mains (m)	1,214	5,691	4,477	468
	Distribution Mains (m)	331	18,331	18,00	5,538
	Energy Centre Footprint (m2)	214	1,012	798	473

Considerable additional network infrastructure would also be required (Table 13). A further 4,477m in the case of the transmission infrastructure, which would be an almost five-fold increase over the 1,214m specified for the initial system. The largest increase in infrastructure terms would result from the additional distribution mains required to service each individual dwelling. As final siting plans are not yet available it is not possible to cost this accurately, in absence of this an allowance of 6m per dwelling has been made (3,000 units). On this basis an additional 18,000m of distribution mains will be required, representing over a 5,500% increase above the initial system specification. As further detail emerges it will be possible to revisit this, but in absence of this detail calculations are constrained by the assumptions made. The additional plant requirement will naturally have an associated impact on the size of the Energy Centre required. To serve the larger network an additional 798m2 will be required to accommodate a the larger 1,012m2 Energy Centre, in comparison to the 214m2 building required for the smaller network. At 900m2 the site currently proposed could not accommodate the larger Energy Centre requirement and an alternative location would be required. As highlighted earlier there are considerable land value and availability constraints in the immediate area surrounding the cobalt business park. A site within the Murton Gap development could be an option, although this would require further consideration by the NTC Murton Gap project team and potentially the development consortium.

Table 14: Phase 1&2 Network Cost Detail

Element		Phase 1	Phase 2	Additional	% Increase
CAPEX	Transmission Mains (£)	1,194,576	5,599,944	4,405,368	469
	Distribution Mains (£)	198,600	10,998,600	10,800,000	5,538
	Total Network Costs (£)	1,563,851	17,209,773	15,645,922	1,100
	Energy Centre & Plant (£)	844,540	3,443,731	2,599,191	408
	Total CAPEX (£)	2,408,391	20,653,504	18,245,113	858
OPEX	Direct Energy & Overhead costs (£)	651,334	2,061,114	1,409,780	316
Income	Gross Income (£)	940,870	3,152,345	2,211,475	335
	Net Income (£)	289,537	1,091,231	801,694	377

Given the extent of the physical extension to the network there are also considerable CAPEX implications as a result (table 14). The additional £4.4m cost in terms of transmission mains above the initial £1.2m requirement represents an almost five-fold increase in capital cost. Although the additional £11m capital requirement for the distribution mains would dwarf the initial capital cost of £198.6k, representing an increase of over 5,500%. Including the additional £2.59m capital requirement for the Energy Centre and plant, the total capital cost for both network phases rises considerably from £2.4m for the initial phase to £20.65m for both phases, an increase of approximately 860%.

Correspondingly the increase in annual OPEX costs including both additional direct input energy costs and network operating overheads is significant at a total of approximately £2.06m per annum for both phases compared to £651k per annum in the initial phase.

Conversely, the resulting increase in system net income is just under 380% at approximately £1.09m per annum compared to £290k per annum in the case of the initial phase.

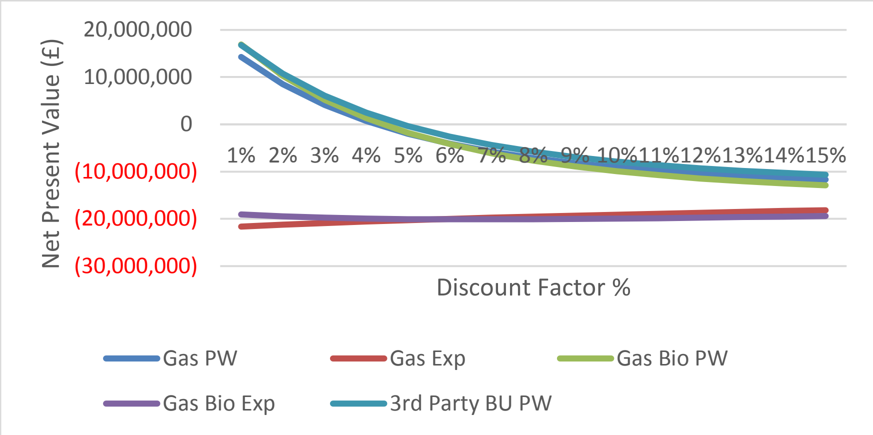

Figure 30: Phase 1&2 Financial Performance

The conclusion to be drawn from this is that the increase in net income at under 380% is insufficient to accommodate the combination of a considerable 860% increase in CAPEX costs along with the 316% increase in OPEX costs. This effect is reflected in the financial performance metrics. Whilst the first phase of the network is able to recover the initial capital investment in approximately 13 years, returning a positive NPV £1.81m at a public sector borrowing rate of 6%. The larger network incorporating both phases can only return a positive NPV of £690k at a 4% borrowing rate (figure 30), which indicates that without significant capital offset the proposal would not be likely to meet either private sector or public sector investment requirements.

On this basis the second phase expansion of the network to include the proposed Murton Gap new development does not seem viable. However, in many ways, given the level of final detail still outstanding regarding the new development, it is too soon to draw this conclusion. The considerable majority of the increased capital cost is incurred by the additional distribution mains required to service each individual dwelling, an additional £10.8m of cost which is not offset by the additional £802k in net income. As highlighted earlier, without the final siting plans for these dwellings, we can only use an indicative 6m of distribution mains per dwelling to derive the associated capital cost. This assumption could be excessive, however in absence of final detail it is not possible to provide a more accurate calculation. Further to this there could also be value engineering opportunities such as passing this additional £10.8m cost onto the development consortium therefore removing the cost burden from the financial model. However, at this stage, without an indicative commitment from the developer, this would introduce an excessive level of optimism-bias into the financial model which cannot be justified.

Whilst we have been able to provide a high-level assessment of the network opportunity posed by the Murton Gap development, given the outstanding detail it is not possible at this stage to carry out a complete analysis. A full analysis can only be undertaken at later stages once the final detail has been made available, although the initial modelling outputs are provided as an addendum to the modelling supplement. As such we advise that the larger A19 North network proposal (incorporating both phases) is not included in the overall evaluation of the six network proposals in this report as it not possible to assess the opportunity to a consistent level of detail as that presented for the other network proposals.

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6.3 A19 South System proposal (Phases 1&2)

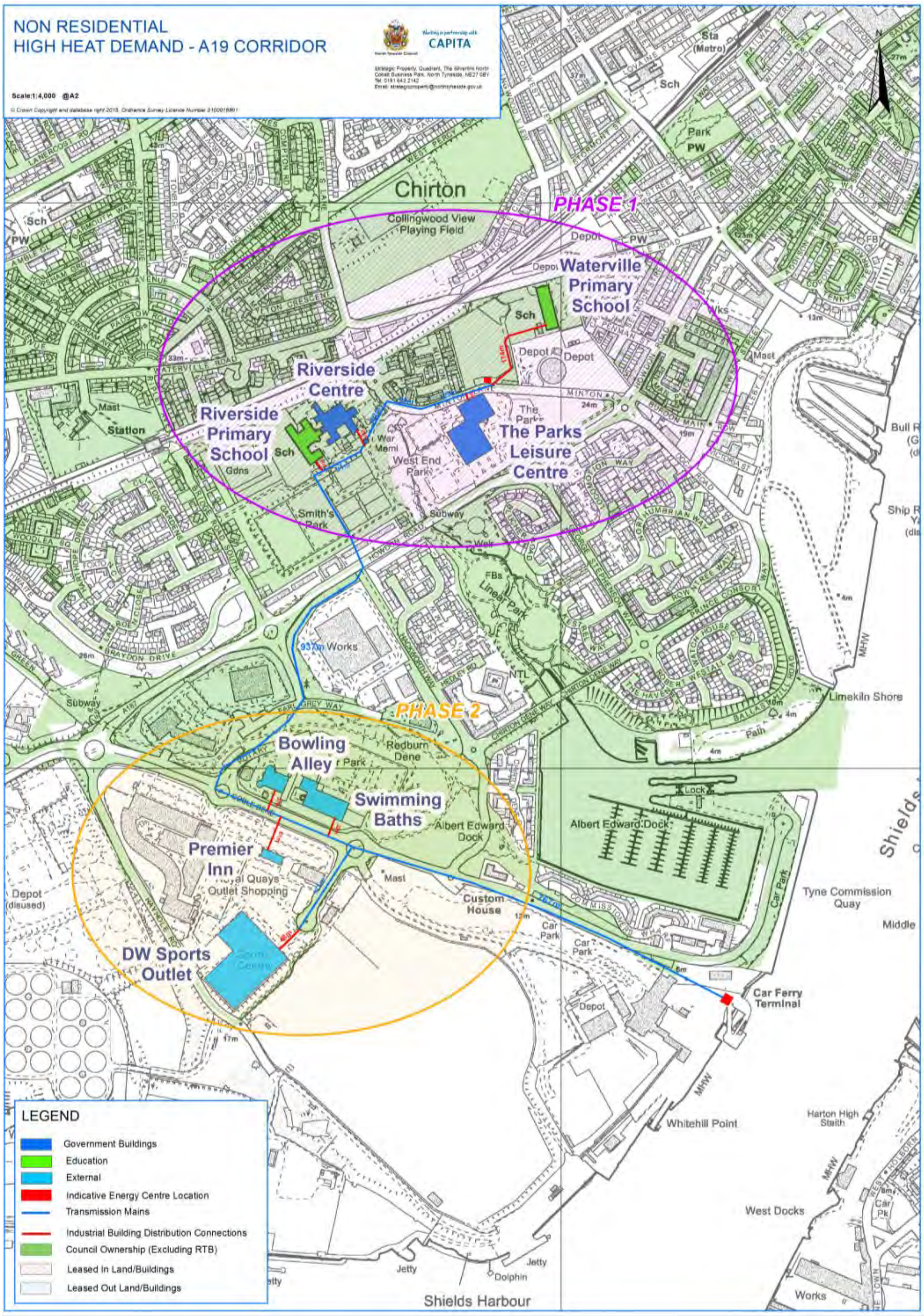

Figure 31: A19 South Phases 1&2 System proposal map

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6.3.1 A19 South System – Anchor Buildings and Energy Centre Location:

Table 15: A19 South - Anchor Building Properties

Phase	Building	Size m2	Annual Heat demand (MWh)	Annual Power demand (MWh)	Annual Cooling demand (MWh)	Data Source	Comments
Phase 1	Riverside Primary School	2,249	337	268	n/a	Actual consumption data from NTC EM System	Medium sized modern Primary school with lower summer baseload & no heating load from June to September
	Waterville Primary School	1,569	139	81	n/a	Actual consumption data from NTC EM System	Smaller modern Primary school with lower summer baseload & no heating load from June to September
	Riverside Children's Centre	3,865	638	82	n/a	Actual consumption data from NTC EM System	Large mixed-use children's centre with extended opening hours and no heating load in July & August
	Parks Leisure Centre	6,916	787	450	69	Actual consumption data from NTC EM System	Dry leisure centre with high DHW demand and fairly constant seasonal load profile.
Phase 2	Wet'n'Wild Leisure Centre	3,574	343	922	36	2013 EPC rating	Wet leisure centre/water-park with high DHW demand and continuous heating load.
	Starbowl Centre	2,748	235	289	28	2013 EPC rating	Indoor Bowling ally with no heating load in July & August
	Premier Inn Hotel	1,318	348	158	92	Modelled on CIBSE TM46 using GIS measurement	Compact Modern budget Hotel with continuous DHW load, seasonal cooling load, and no heating load in July & August.
	DW Fitness Soccer dome	9,525	663	1000	95	Modelled on CIBSE TM46 using GIS measurement	Large mixed-use retail with large food store & smaller retail parade – assumed no heating load in July & August

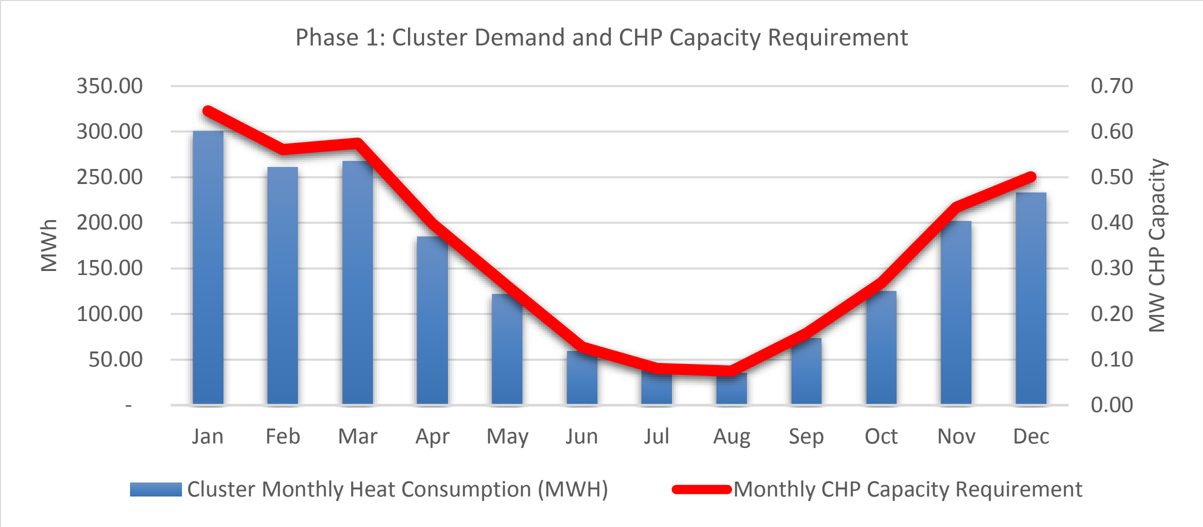

Figure 32: A19 South Phase 1 - Monthly Heat Demand &CHP Capacity Requirement

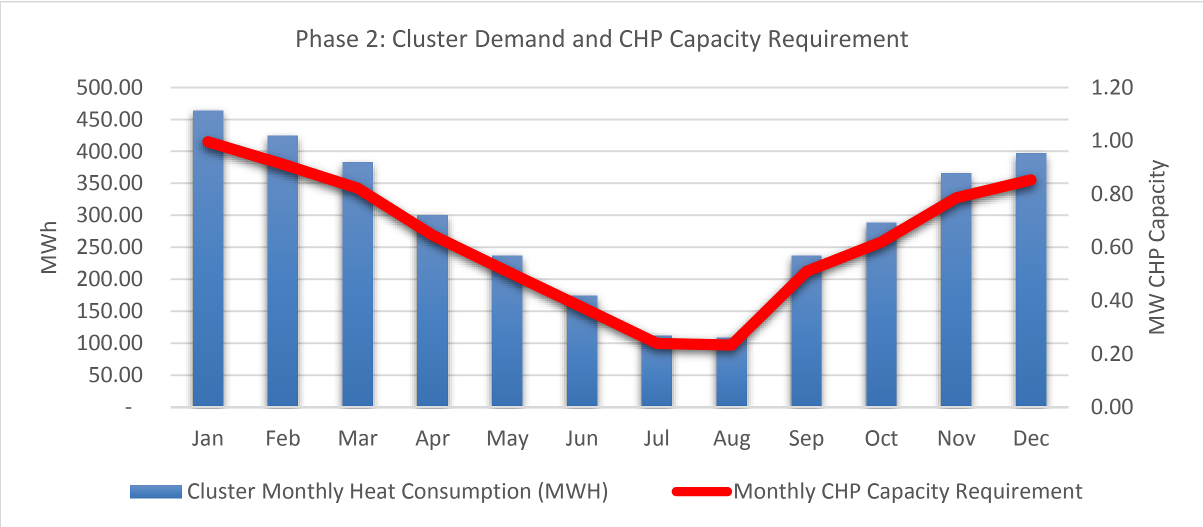

Figure 33: A19 South Phase 2 - Monthly Heat Demand &CHP Capacity Requirement

The A19 South cluster includes a number of buildings with a diverse range of uses (table 15). With three primary schools there is a noticeable seasonal effect on the annual heat demand across the cluster, with a noticeable drop in demand in July and August as a result of summer school closures as identified in the graphic above (figure 32 & 33). This is offset to some extent by the two dry leisure centres and the Wet'n'Wild wet leisure centre/water park which support the base-load over the warmer summer months. The higher demands are provided by the Parks Leisure centre, the Children's centre, and the DW Fitness Soccer dome.

Five of the nine buildings within the cluster are NTC operational buildings with actual consumption data available, with the remaining for buildings reliant on derived consumption data, two of these buildings would be significant anchors within the network so further attention at the feasibility stage will be required to test the benchmark outputs. To highlight this, the demand from the wet'n'wild leisure centre seems low given the type of building use, the figure is derived from the 2013 EPC rating and the measured floor area recorded on the EPC certificate, rather than calculated using the appropriate benchmark. As the EPC constitutes a measured survey, undertaken in-line with a nationally agreed methodology, the outputs have been used to derive the building's consumption in preference of a benchmark approach. However, a further check should be undertaken prior to detailed feasibility analysis.

Figure 34: A19 South - Aerial Satellite View

As identified on the proposal map (figure 31) there is a good level of NTC land ownership within the proposal area with the majority of the proposed anchor buildings accessible via NTC owned land. In addition to the preferable land ownership situation the satellite image above (figure 34) demonstrates that there are considerable amounts of green space in many areas which supports flexibility in terms of network routing as well as associated opportunities to value-engineer network infrastructure costs.

6.3.2 Energy Centre Location – Justification & Rationalisation

The satellite image below (Figure 31) identifies a small site to the top of the image across the road from the Parks Leisure centre. This site is centrally located within the phase 1 cluster and whilst it is currently being used for containerised storage for the adjacent football pitches this is only a temporary use. As part of a wider corporate accommodation review the site has been identified as being surplus to operational requirements, however the NTC property function have indicated that the site has little potential development value due to it's size. Despite its size the site could comfortably accommodate the maximum 120m2 energy centre requirement, along with any additional requirement for biomass or thermal storage.

Further assessment of proposed Energy Centre sites; including; Air Quality Assessment, Noise Disturbance Assessment, Visual Impact Assessment, and Planning Risk, will be undertaken at subsequent stages.

Figure 35: A19 South – Energy Centre Location - Aerial Satellite View

The NTC Asset Management and NTC Energy Management function have confirmed that the three NTC operational buildings within the cluster are heated by traditional medium temperature wet heating systems operating at approximately 80°C flow with 70°C return. Domestic hot water is supplied by with calorifiers operating at 60°C flow and 50°C return. Further detail on the non-NTC buildings will have to be sought at the feasibility stage however, given the age and type of construction of the external buildings it is assumed that traditional wet heating systems are in use. On this basis it is assumed that all buildings are suitable for connection to a district heating network and that none of the buildings identified present insurmountable constraints in terms of the proposal.

6.3.3 System configuration and Technology Options:

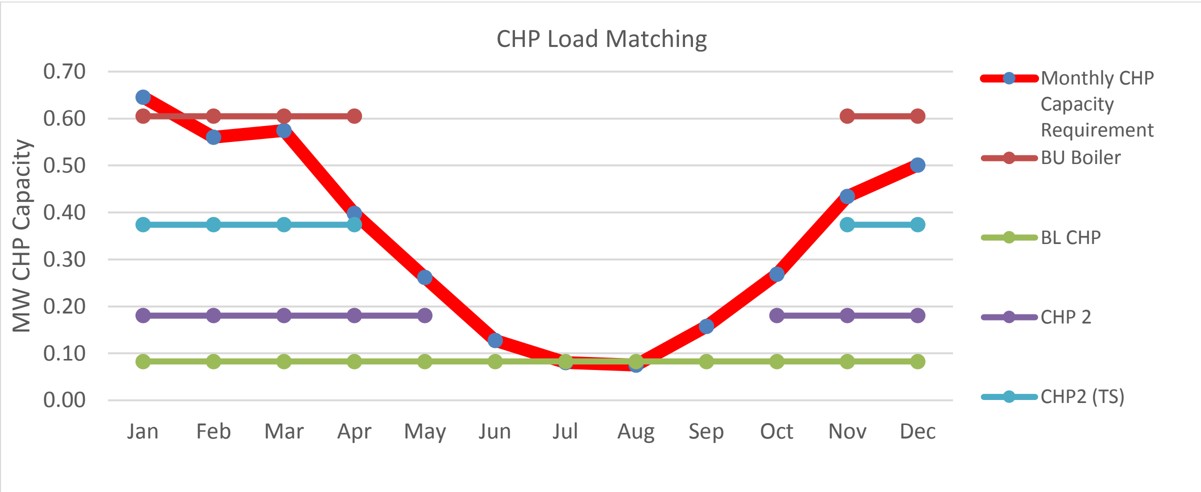

Figure 36: A19 South – Phase 1 - Monthly CHP Capacity Requirement & CHP Load Matching

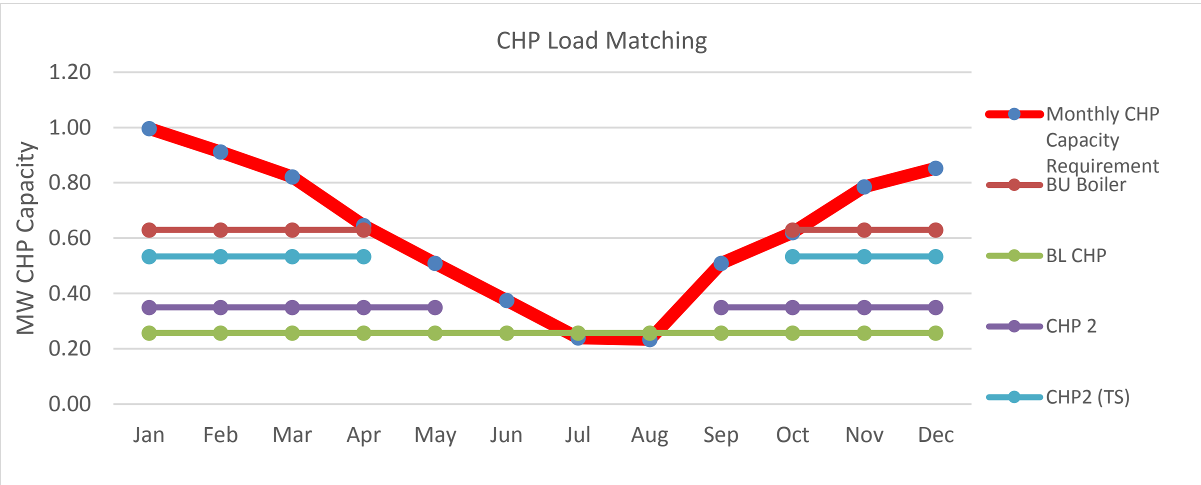

Figure 37: A19 South – Phase 2 - Monthly CHP Capacity Requirement & CHP Load Matching

6.3.2.1 System configuration and Technology Options – Phase 1:

With the lowest monthly heat & DHW demand across the cluster occurring in August, the corresponding base-load of 34.91 MWh would dictate a maximum CHP size of 80kWt/65kWe, with a top-up boiler capacity requirement of 90kWt for gas fired boilers, or 1MWt for Biomass boilers (figure 36). On a base-load CHP sizing basis only 22% of the annual heat demand would be served by the CHP unit with the remainder being provided by the back-up boilers.

If a modular CHP approach were adopted the smaller base-load CHP unit could be supported a larger 180kWt/140kWe CHP unit to provide a combined capacity of 260kWt/205kWe which would provide approximately 62% of the annual heat demand and reducing back-up boiler capacity requirement to

60kWt for gas fired boilers, or 66kWt for Biomass boilers. Further to this the modular CHP approach would generate an additional 671 MWh of power for sale via private wire, or export.

To connect the potential anchor buildings identified, a total 314m of transmission mains would be required at a capital cost of £308,976 with a further 228m of distribution mains to individual buildings at a cost of £136,800, and an overall cost of £47,518 for building connections.

Total capital costs for the gas CHP & gas top-up network including network infrastructure, plant and energy centre costs comes to £730,556. Whereas the total cost for the biomass top-up system comes in at a higher total capital cost of £994,098 due to the higher cost of biomass heating plant and ancillary equipment (table 16).

With a combined volume of 22.2m3 the network transmission mains for Phase 1 provide an inherent storage capacity of approximately 1.01MWh, or the equivalent system run time of 1.5 hours. An additional capacity of 70m3 has been specified for the modular CHP thermal storage model providing an additional 3MWh of storage at a cost of £60,026. A slightly smaller vessel has been specified for the single CHP thermal storage model at 52m3 (2.4MWh) at a cost of £44,006

Annual power generation for the larger modular CHP configuration, once adjusted for network parasitic electrical load, provides approximately 1,025MWh. The combined annual electrical consumption of the NTC operational buildings within the cluster is approximately 1,048MWh or around 102% of the total generated power. On this basis the assumption that all of the CHP generated power can be sold via private wire can be upheld, although lower system revenues based on electricity sale exclusively at export prices will be assessed in the interests of stress testing the proposals.

Table 16: A19 South Phase 1 System Cost Summary

System	Network Infrastructure costs (£)	Energy Centre & Plant costs (£)	Potential CO2 abatement (tonnes p/a)	Total costs (£)
Gas CHP & TU	493,294	237,262	305	**730,556**
Gas CHP biomass top-up	493,294	500,804	474	**994,098**

Table 17: A19 South Phase1 System Annual Income Profile

System Annual Income profile		
Income Item	**Gas CHP & TU (£)**	**Gas-Biomass (£)**
Energy Sales (Private Wire only)	222,323	222,323
Energy Sales (Export Only)	147,787	147,787
RHI Income	-	38,982
Standing Charge	25,685	25,685
Business rates (Cost not income)	10,949	10,949

6.3.2.2 System configuration and Technology Options – Phase 2:

With the additional load provided by the non-NTC buildings identified in Phase 2 the initial base-load of 35.91MWh is raised to 109MWh. This higher would dictate a maximum CHP size of 260kWt/200kWe, with a top-up boiler capacity requirement of 1.34MWt for gas fired boilers, or 1.46MWt for Biomass boilers (figure 37). On a base-load CHP sizing basis only 37% of the annual heat demand would be served by the CHP unit with the remainder being provided by the back-up boilers.

If a modular CHP approach were adopted the base-load CHP unit could be supported a larger 350kWt/270kWe CHP unit to provide a combined capacity of 610kWt/470kWe which would provide approximately 77% of the annual heat demand and reducing back-up boiler capacity requirement to 630kWt for gas fired boilers, or 680kWt for Biomass boilers. Further to this the modular CHP approach would generate an additional 1,184 MWh of power for sale via private wire, or export.

To connect the phase 2 buildings an additional 1,216 of transmission mains would be required at a capital cost of £1,244,760 with an additional 356m of distribution mains to individual buildings at a cost of £213,600, and an additional cost of £39,733 for building connections.

Under the phase 2 scenario Capital costs for the gas CHP & gas top-up network including network infrastructure, plant and energy centre costs are raised by an additional £1,694,452 to a total of £2,425,008. Whereas the additional £1,976,199 required for the biomass top-up system results in a total capital cost of £2,706,755 (table 18).

The additional transmission mains required for Phase 2 provide an overall network volume of 111.6m3 with an inherent storage capacity of approximately 5.07MWh, or the equivalent system run time of 4.5 hours. An additional capacity of 70m3 has been specified for the modular CHP thermal storage model providing an additional 3MWh of storage at a cost of £60,026. A slightly smaller vessel has been specified for the single CHP thermal storage model at 52m3 (2.4MWh) at a cost of £44,006

Annual power generation for the larger modular CHP configuration, once adjusted for network parasitic electrical load, provides approximately 2,690MWh. The combined annual electrical consumption of the NTC operational buildings within the cluster is approximately 872MWh or around 32% of the total generated power, and the combined annual consumption of the non-NTC approximately 2,369MWh, or 88% of the total generated power. On this basis the assumption that all of the CHP generated power can be sold via private wire can be upheld, although lower system revenues based on electricity sale exclusively at export prices will be assessed in the interests of stress testing the proposals.

Table 18: A19 South – Phase 1&2 Total Cost Summary

System	Network Infrastructure costs (£)	Energy Centre & Plant costs (£)	Potential CO2 abatement (tonnes p/a)	Total costs (£)
Gas CHP & TU	1,991,387	433,621	690	**2,425,008**
Gas CHP biomass top-up	1,991,387	715,368	871	**2,706,755**
Gas CHP WHSP top-up	1,991,387	1,930,886	871	**3,922,273**

Table 19: A19 South Phase 1&2 System Annual Income Profile

System Annual Income profile			
Income Item	**Gas CHP & TU (£)**	**Gas-Biomass (£)**	**Gas-WSHP (£)**
Energy Sales (Private Wire only)	455,238	455,238	455,238
Energy Sales (Export Only)	286,138	286,138	286,138
RHI Income	-	41,862	63,976
Standing Charge	25,685	25,685	25,685
Business rates (Cost not income)	23,823	23,823	23,823

6.3.3 Phase 1 Network options – Financial Assessment:

A techno-economic analysis is presented for the A19 South cluster for the following five technology options:

1. Gas CHP unit using private wire electrical distribution
2. Gas CHP unit with electricity exported to the national grid
3. Gas CHP unit plus biomass heat generation with private wire electrical distribution
4. Gas CHP unit plus biomass heat generation with electricity exported to the national grid
5. NWL Waste heat system with CHP

Table 20: A19 South Phase 1 Summary Table

A19 South Phase 1				
		Appraisal (years)	**IRR**	**NPV @ 6%**
Gas CHP Private Wire	Without TS	25	6%	16,822
		40	8%	151,763
	With TS	25	12%	483,821
		40	13%	732,476
Gas CHP Export	Without TS	25	-	-865,679
		40	-	-899,409
	With TS	25	-	-1,099,210
		40	-	-1,153,116
Gas CHP + Bio Private Wire	Without TS	25	6%	-10,366
		40	7%	166,898
	With TS	25	10%	417,445
		40	11%	676,689
Gas CHP + Bio Export	Without TS	25	-	-892,867
		40	-	-884,274
	With TS	25	-	-1,165,587
		40	-	-1,208,903

Table 20 provides an overview of the financial performance of the four system options for the A19 South Phase 1 network proposal at an assumed public sector borrowing rate of 6%. As the table identifies, neither of the export based systems return a positive NPV suggesting that they are not viable given the capital investment required. The private wire systems however return a positive NPV in most cases both with, and without thermal storage.

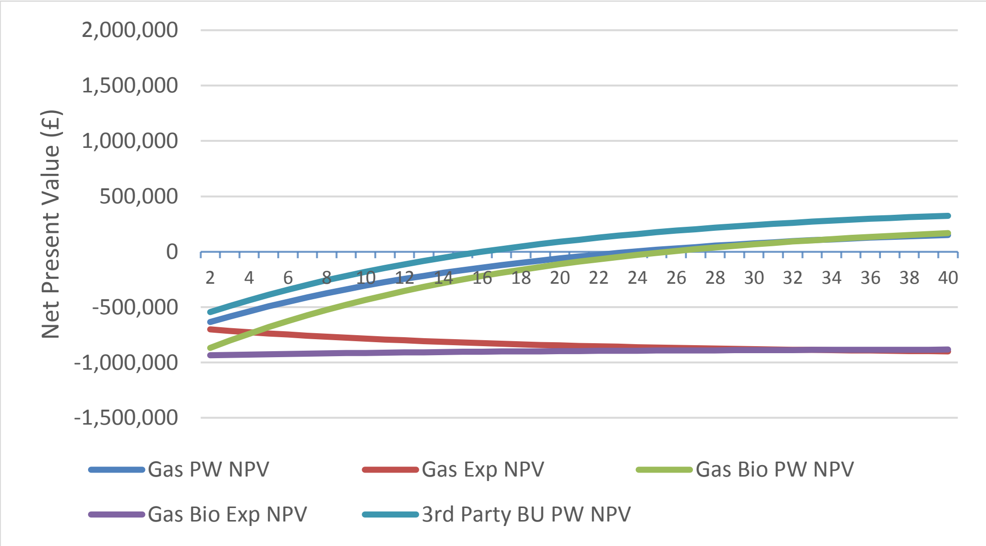

Figure 38: A19 South Phase 1 Modular CHP - Outline Cost Evaluation (NPV discount rate @ 6%)

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As the figure 38 demonstrates, the modular CHP private wire systems are able to generate a positive NPV repaying the capital investment from year 25 onwards in the case of the gas CHP & gas top-up system, and year 27 onwards in the case of the biomass top-up system. Although neither export based system is able to repay the capital investment.

Figure 39 highlights that whilst the modular private wire systems are able to return a positive NPV at the 6% public borrowing rate, neither system is able to maintain positive value at the higher 10% private financing rate. The export only systems do not maintain positive value at either rate.

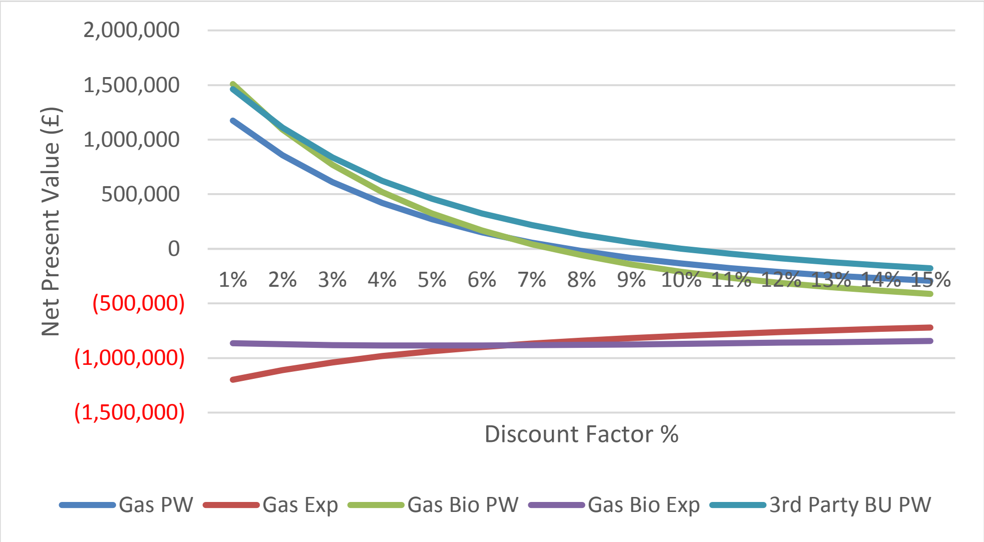


Figure 39: A19 South Phase 1 Modular CHP - NPV DCF Sensitivity Analysis

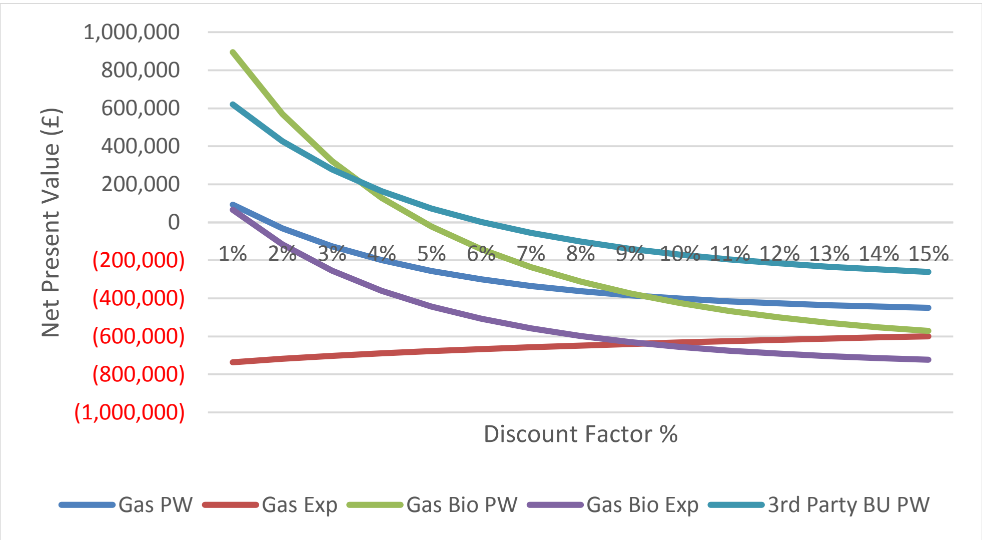


Figure 40: A19 South Phase 1 Base Load CHP - NPV DCF Sensitivity Analysis

In the case of the base load systems no configuration is able to return a positive value at the lower 6% rate of the longer 40-year evaluation period. As is highlighted by figure 40 no base load configuration, whether export or private wire, would be likely to secure private or public financial support.

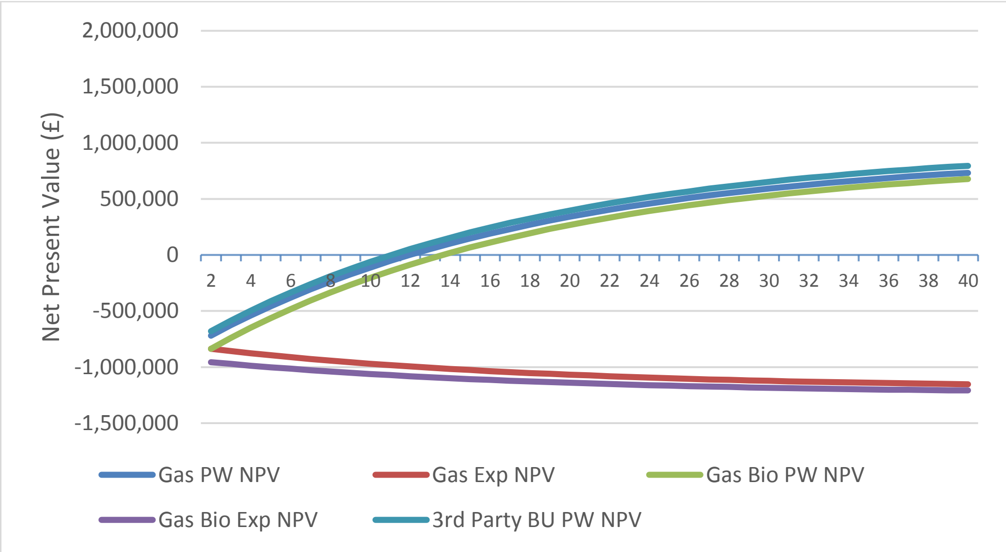


Figure 41: A19 South Phase 1 Modular CHP with Thermal Store - Outline Cost Evaluation (NPV discount rate @ 6%)

The addition of thermal storage in the case of the modular systems provides significant improvement in terms of capital repayment and NPV. Positive NPV values are achieved from approximately year 14 at the latest reducing payback times by around 10 years (figure 41).

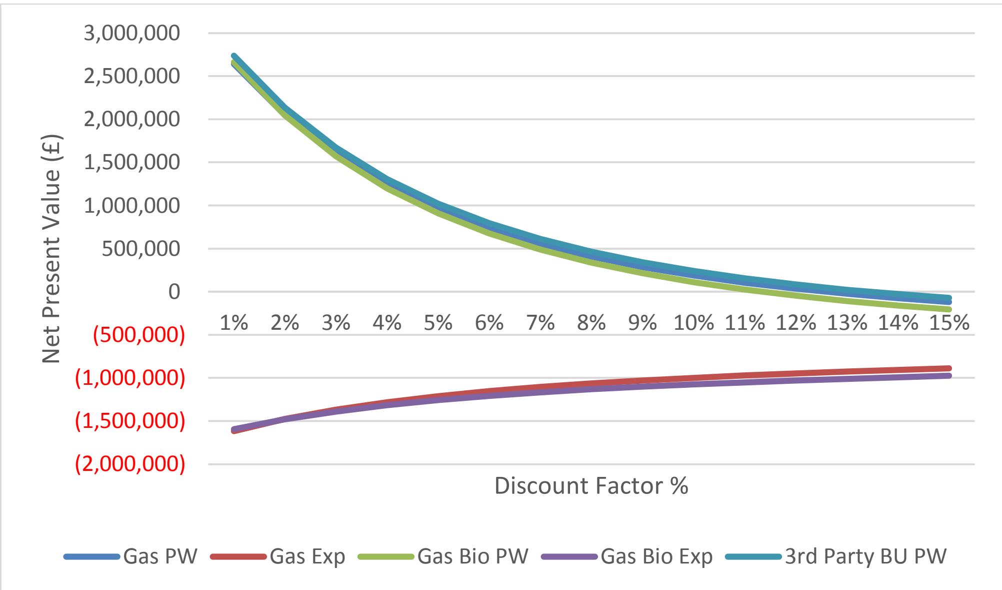


Figure 42: A19 South Phase 1 Modular CHP with Thermal Store - NPV DCF Sensitivity Analysis

This positive improvement is reflected by figure 38 which highlights that the higher 10% private financing rate can be achieved following the implementation of thermal storage in the case of the modular private wire systems. The export only systems alternatively are still unable to achieve positive value for either rate. The base load system is also unable to meet either financing requirement through the implementation of thermal storage (figure 43).

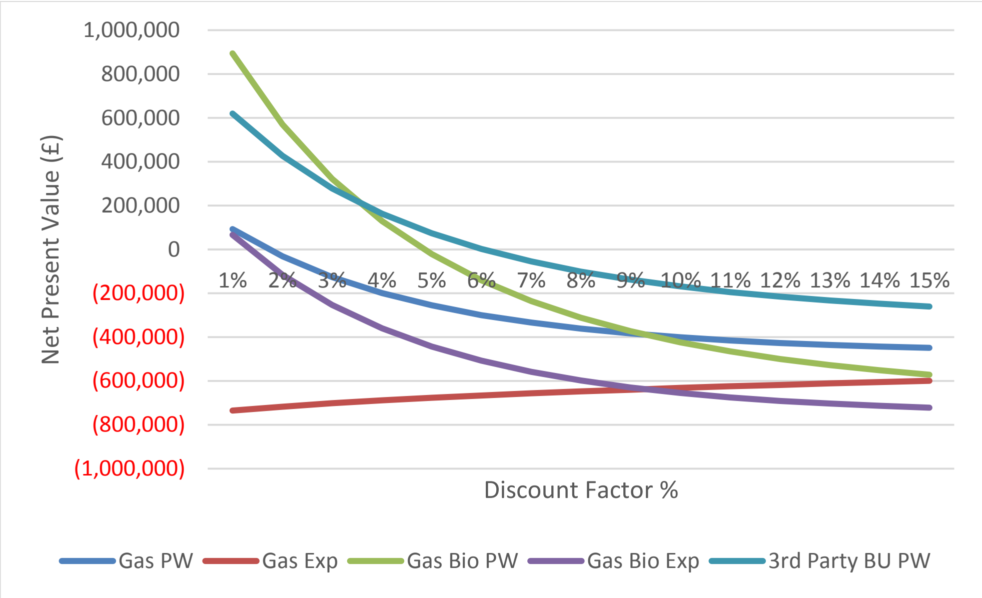


Figure 43: A19 South Phase 1 Base Load CHP with Thermal Storage - NPV DCF Sensitivity Analysis

6.3.4 Phase 2 Network options (Phases 1&2 incorporated) – Financial Assessment:

A techno-economic analysis is presented for the A19 South cluster for the following five technology options:

1. Gas CHP unit using private wire electrical distribution
2. Gas CHP unit with electricity exported to the national grid
3. Gas CHP unit plus biomass heat generation with private wire electrical distribution
4. Gas CHP unit plus biomass heat generation with electricity exported to the national grid
5. Gas CHP unit plus Water-source heat pump with private wire electrical distribution

Table 21: A19 South Phase 2 Summary Table

A19 South Phase 2				
		Appraisal (years)	**IRR**	**NPV @ 6%**
Gas CHP Private Wire	Without TS	25	-	-653,292
		40	-	-340,903
	With TS	25	-	-609,828
		40	-	-262,769
Gas CHP Export	Without TS	25	-	-2,631,752
		40	-	-2,697,502
	With TS	25	-	-3,061,405
		40	-	-3,182,910
Gas CHP + Bio Private Wire	Without TS	25	-	-681,294
		40	-	-323,456
	With TS	25	-	-667,732
		40	-	-303,999
Gas CHP + Bio Export	Without TS	25	-	-2,659,755
		40	-	-2,680,055
	With TS	25	-	-3,119,309
		40	-	-3,224,140
Gas CHP + WSHP (PW)	Without TS	25	-	-1,750,446
		40	-	-1,377,784
	With TS	25	-	-1,582,072
		40	-	-1,212,901

Table 21 provides an overview of the financial performance of the larger potential network. The assumption is that once phase 2 will absorb phase 1 once completed, as such this table and the following financial analysis provides an assessment of the two combined phases.

As the table highlights the assumed economies of scale are not apparently evident. The addition of further non-NTC operational loads does not offset the additional investment required to combine the two phases into one large network. Neither of the export only scenarios are able to generate a positive return over the longer 40 year assessment period at the lower 6% target rate. The introduction of low-carbon heat via the implementation of a large scale water-source (river source) heat pump is unable to be supported given the negative returns. None of the private wire systems are able to generate a positive position at the lower 6% borrowing rate, although the private wire thermal storage systems come closest achieving a positive value at a 5% rate.

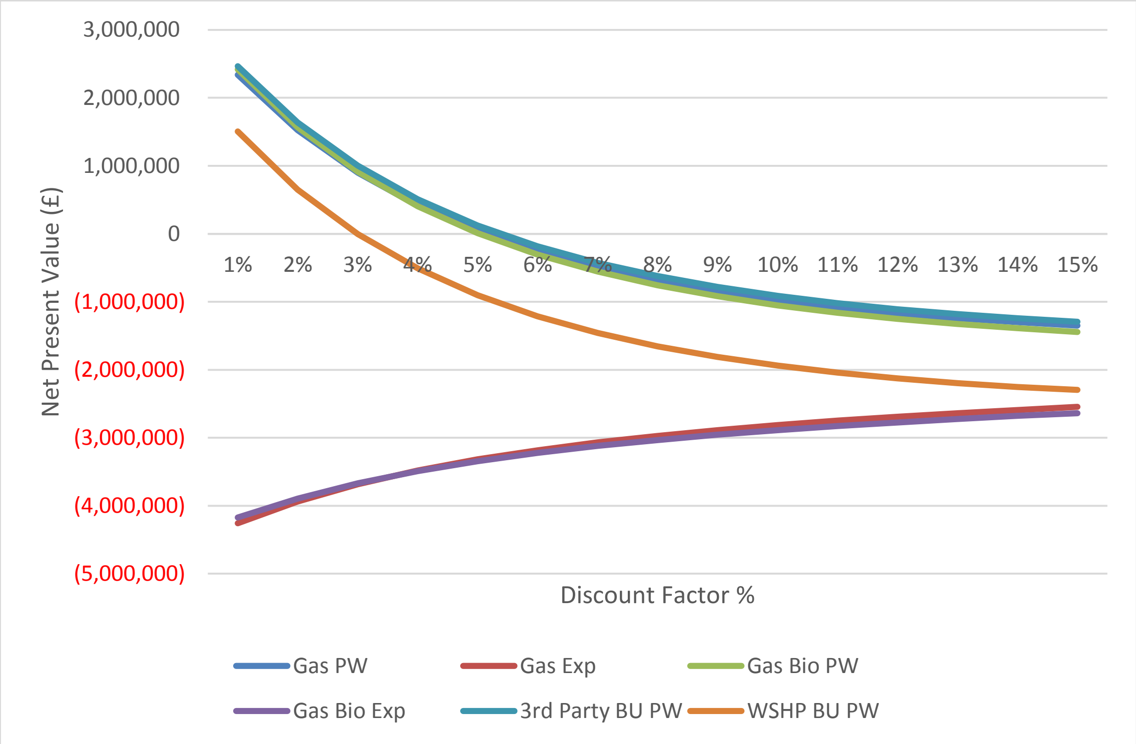


Figure 44: A19 South Phase 2 Modular CHP with Thermal Store - NPV DCF Sensitivity Analysis

Figure 44 above demonstrates that with the implementation of thermal storage no system configurations are able to generate a positive NPV position across the longer 40-year appraisal period (at the lower 6% rate). The Gas CHP & gas top-up, and biomass top-up private wire systems are able to maintain positive NPV at a rate of around 5%, however to achieve the lower 6% target rate a capital offset of approximately 12.5% would be required.

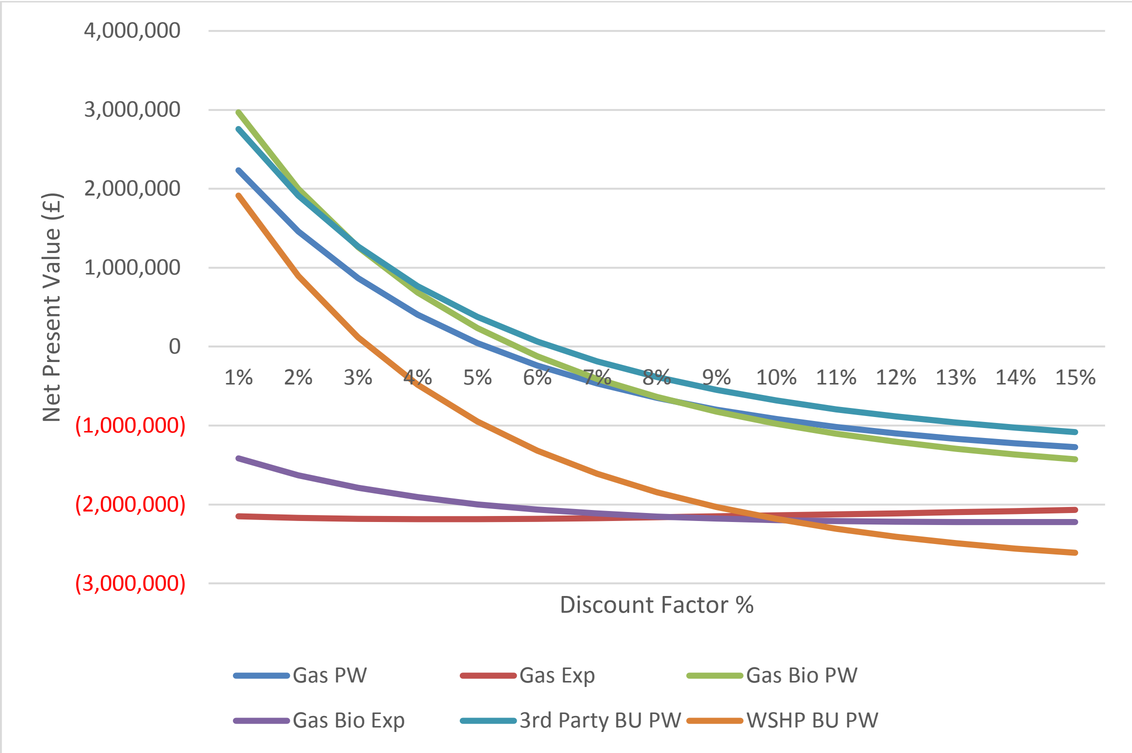


Figure 45: A19 South Phase 2 Base Load CHP with Thermal Storage - NPV DCF Sensitivity Analysis

Figure 45 demonstrates that in the case of the base-load thermal storage systems all configurations are still unable able to generate a positive NPV position across the longer 40-year appraisal period (at the lower 6% rate). The Gas CHP & gas top-up, and biomass top-up private wire systems are closest being able to maintain positive NPV at a rate of around 5%, however to achieve the lower 6% target rate a capital offset of approximately 12.5% would be required.

Extensive further analysis of the phase 2 proposal is provided on pages 13 and 14 of the report supplement. In the interests of keeping the main report as concise as possible there is little value in providing further extensive analysis of the phase 2 proposal. The analysis undertaken, and supported by the report supplement document highlights that the extension of the system to pick up the additional external buildings does nothing to improve the financial performance of the proposal, and conversely it actually significantly weakens the more robust phase 1 proposal.

6.3.5 Proposal Evaluation – Summary:

The mix of anchor buildings within the first phase of the proposal provides a good amount of diversity on the phase 1 networks overall heat demand profile with the longer operating hours of the leisure centre and children's centre offsetting the shorter days of the two schools, the continuous load profile of the leisure centre should also offset some of the seasonality of the individual school's demand profiles. All of the four anchor buildings are NTC sites signifying that the success of the network is not dependant on commitment from external parties. The combined power demand from the NTC buildings accounts for approximately 102% of the system generated electricity indicating that there is also no reliance on external parties for private wire electricity sale.

In terms of physical constraints there is little to cause real concern. Whilst there are some constraints as a result of land which is owned by NTC but leased out (figure 31), consultation with the NTC property service has confirmed that these leases are favourable and should not present any significant obstacle. A suitable vacant site for the energy centre is available across the road to the north of the leisure centre (figure 35).

There are no insurmountable land ownership constraints in term of phase 1 proposed network routes and the majority of land surrounding the indicative network locations is within NTC ownership. Further to this as the satellite overhead image of the proposal area (figure 29) identifies there are significant amounts of green-space and associated soft-dig routes to reduce trenching costs. Phase 2 proposed network routings require the crossing of Howdon road to connect the two cluster areas and whilst this could require the staged closure of a fairly busy traffic route this is not considered to be prohibitive. Beyond this there are no significant anticipated constraints in terms of the indicative phase 2 network routing.

In terms of financial viability for phase 1, table 21 demonstrates that whilst neither grid-export configurations are viable, both modular private wire options are viable both with and without thermal storage achieving a positive NPV at the 6% public rate and a range of IRR returns from 6-8% in the case of the systems without thermal storage, and 10-13% in the case of those with, across both the shorter 25 year, and longer 40 year appraisal period. All but the base-load CHP private wire systems are able to repay the capital outlay generating a positive NPV over the shorter 25 year assessment period. Modular thermal storage systems are able to sustain rates of return up to 11% meeting private financing requirements.

There is no gap-funding requirement for either of the phase 1 private wire configurations, which combined with the investment returns identified above, suggest that this is a financially robust proposal that would secure interest from both public and private sectors.

In terms of financial viability for phase 1 the results are a lot less positive. No systems, export or private wire, with or without thermal storage are able to return positive NPV's at the lower 6% rate. This is the case for all technologies, including the biomass and WHSP top-up systems which are supported by the RHi tariff. The highest rate at which a positive NPV can be achieved is 5% for the modular CHP systems with thermal storage, 4% is the highest rate that can be achieved without thermal storage. Gap funding in the region of 10-15% would be required to meet public borrowing requirements, or in the region of 30-35% to meet private financing requirements. On this basis none of the phase 2 system proposals would be likely to secure public or private sector financing interest.

When the additional load risk, in terms of both heat and power, is factored into the evaluation of the financial performance of the phase 2 proposal it is clear that this would not warrant further investigation at feasibility stage.

The phase 1 proposal however remains considerably robust in terms of financial performance and with the lack of any significantly physical or technical risk identified at this stage the strength of phase 1 as a stand-alone proposal suggest it would be a good candidate for further detailed analysis over the subsequent feasibility stages.

6.4 Killingworth System proposal

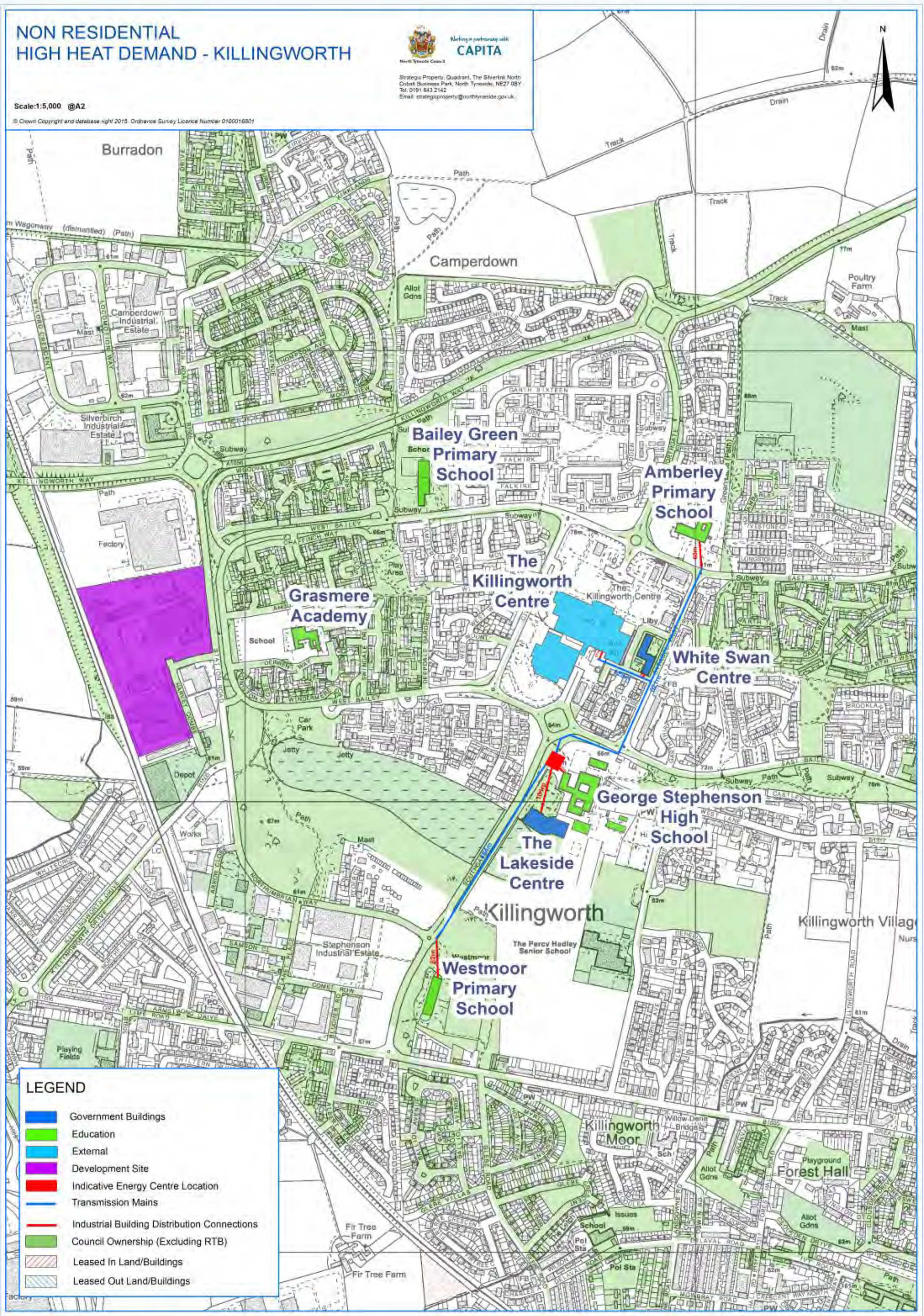
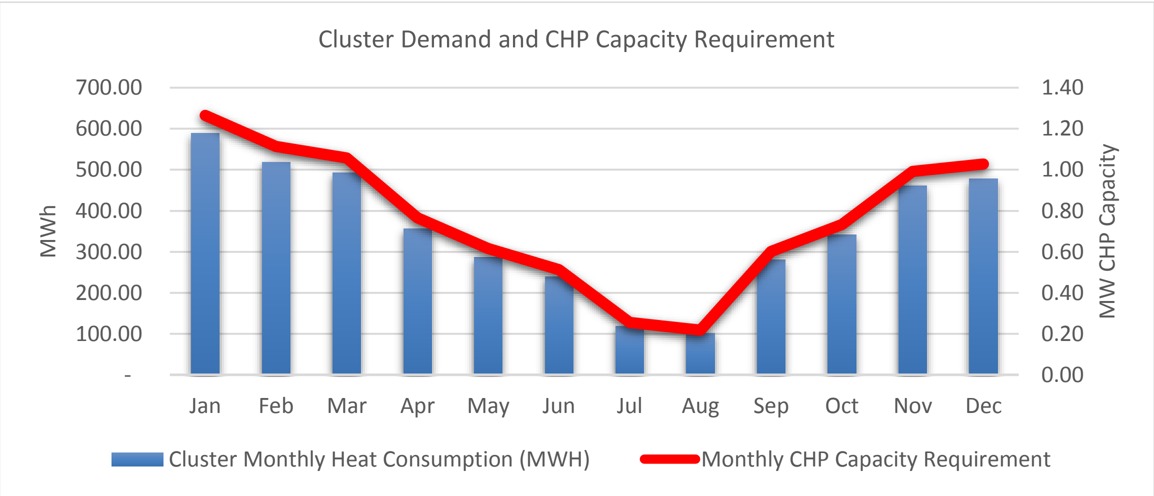


Figure 46: Killingworth System proposal map

6.4.1 Killingworth System – Anchor Buildings and Energy Centre Location:

Table 22: Killingworth - Anchor Building Properties

Building	Size m2	Annual Heat demand (MWh)	Annual Power demand (MWh)	Annual Cooling demand (MWh)	Data Source	Comments
George Stephenson High School	9,305	794	445	n/a	Actual consumption data from NTC EM System	Large older Secondary school with lower summer base-load & no heating load from June to September
Amberley Primary School	2,008	230	93	n/a	Actual consumption data from NTC EM System	Medium sized older Primary school with lower summer base-load & no heating load from June to September
Westmoor Primary	1,677	117	53	n/a	Actual consumption data from NTC EM System	Smaller modern Primary school with lower summer base-load & no heating load from June to September
White Swan Centre	5,280	619	228	53	Actual consumption data from NTC EM System	Large mixed-use customer service centre with no heating load in July & August
Lakeside Leisure	4,300	1,084	604	43	Actual consumption data from NTC EM System	Modern wet leisure centre with high DHW demand and fairly constant seasonal load profile.
Killingworth Shopping Centre	21,500	2,701	12,787	215	Modelled on CIBSE TM46 using GIS measurement	Large mixed-use retail with large food store & smaller retail parade – assumed no heating load in July & August



As table 22 identifies there is a good range of diversity in terms of the types of buildings identified within the Killingworth cluster. Whilst there is an element of seasonality introduced by the 3 schools within the cluster which affects the annual heat demand profile, the large secondary school provides considerable demand over the winter heating months and the continuous demand from the Lakeside leisure centre serves to bolster the base-load heat demand throughout the summer months when the demand from schools drops off.

Five of the six buildings within the cluster are NTC operational buildings with actual consumption data available, with only the Killingworth shopping centre reliant on modelled data giving a good overall level of confidence in the input data used to assess the district heating opportunity.

As the proposal map above (Figure 46) demonstrates much of the land within the immediate area sits within NTC ownership which is of significant benefit to the network proposal in terms of options for network routing and value engineering. Further to this the satellite image below (Figure 47) identifies significant green space which will aid network routing, and whilst a number of public roads and footpaths could present constraints to the indicative network routing, in general the constraints are limited and the conditions are good with numerous soft-dig opportunities to keep network infrastructure costs down.

Figure 47: Killingworth - Aerial Satellite View

6.4.2 Energy Centre Location – Justification & Rationalisation

The satellite image (Figure 48) identifies a site immediately north-west of the George Stephenson secondary school of approximately 3,000m2 that is within NTC ownership, and could feasibly accommodate a substantial energy centre. The site is centrally located within the cluster and is well situated in terms of potential network routes. Whilst the instatement of vehicular access would be required, the cost of this would likely be offset by the lower construction costs associated with green-field development.

Further assessment of proposed Energy Centre sites; including; Air Quality Assessment, Noise Disturbance Assessment, Visual Impact Assessment, and Planning Risk, will be undertaken at subsequent stages.

Figure 48: Aerial Satellite View (2)

As the proposal map (Figure 42) indicates, the current NTC depot site to the left of the map is earmarked for sale and future re-development. Although there are currently no firm proposals for this site it could present an opportunity for a further phase of development for this system. As identified within the Hydraulic Modelling section there is significant additional heat capacity built into the modelled system mains infrastructure to cater for future network expansion. Within this network specifically, there is upwards of 3 MW of additional heat capacity can that could be accommodated by the mains specified which should be sufficient to facilitate significant future expansion of the system.

Discussions with the NTC Asset Management and NTC Energy Management function have confirmed that the five operational buildings within the cluster are heated by traditional medium temperature wet heating systems operating at approximately 80°C flow with 70°C return, with calorifiers providing domestic hot water at 60°C and return no lower than 50°C (in line with Legionella compliance regulation). The exact detail of the Killingworth shopping centre plant configuration is not known but it is assumed that space heating is produced by a traditional central boiler setup operating to 80°C flow with 70°C return (based on the type of air handling systems observed during a site visit), with domestic hot water calorifiers operating on similar parameters to the NTC operational buildings. On this basis it is assumed that all buildings are suitable for connection to a district heating network and that none of the buildings identified present insurmountable constraints in terms of the proposal.

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6.4.2 System configuration and Technology Options:

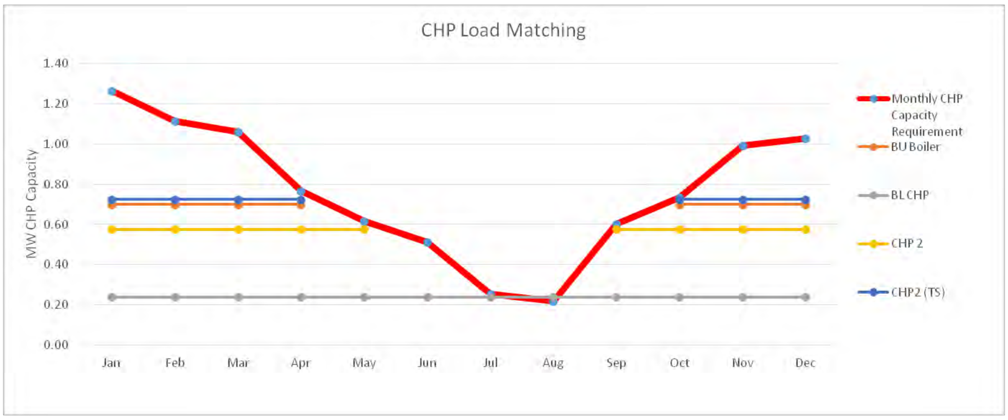


Figure 49: Killingworth - Monthly CHP Capacity Requirement & CHP Load Matching

With the lowest monthly heat & DHW demand across the cluster occurring in August (figure 49), the corresponding base-load of 100.64 MWh would dictate a maximum CHP size of 240kWt/190kWe, with a top-up boiler capacity requirement of 1.67MWt for gas fired boilers, or 1.82MWt for Biomass boilers. On a base-load CHP sizing basis only 29% of the annual heat demand would be served by the CHP unit with the remainder being provided by the back-up boilers.

If a modular CHP approach were adopted the smaller base-load CHP unit could be supported a larger 580kWt/450kWe CHP unit to provide a combined capacity of 820kWt/634kWe which would provide approximately 85% of the annual heat demand and reducing back-up boiler capacity requirement to 700kWt for gas fired boilers, or 760kWt for Biomass boilers. Further to this the modular CHP approach would generate an additional 2,166 MWh of power for sale.

Whilst Killingworth Boating Lake lies within close proximity of the network proposal this is a shallow, static body of water which will have a significantly lower heat capacity than a flowing tidal river, as such it is assumed that the heat potential of the lake would not be significant enough to warrant further exploration. There is no detail available via the National Heat Map water-source layer for the lake, and in absence of available desktop data it has been assumed that the higher capital costs associated with water sourced heat technologies would render this option unfeasible.

For both the gas CHP & gas top-up, and biomass top-up system options electricity sale via a Private-wire only, and export only approaches have been modelled to establish the value of the different approaches.

To connect the potential anchor buildings identified, a total 1,203m of transmission mains would be required at a capital cost of £1,183,752 with a further 279m of distribution mains to individual buildings at a cost of £167,400, and an overall cost of £109,540 for building connections.

Total capital costs for the gas CHP & gas top-up network including network infrastructure, plant and energy centre costs comes to £2,022,047. Whereas the total cost for the biomass top-up system comes in at a higher total capital cost of £2,338,495 due to the higher cost of biomass heating plant and ancillary equipment (table 23).

With a combined volume of 85.04m3 the network transmission mains provide an inherent storage capacity of approximately 3.87MWh, or the equivalent system run time of 2.83 hours. An additional capacity of 82.27m3 has been specified for the modular CHP thermal storage model providing an additional 3.7MWh of storage at a cost of £69,353, the same vessel has been specified for the single CHP thermal storage model as this provides the closest fit to the cluster demand profile.

Annual power generation for the larger modular CHP configuration, once adjusted for network parasitic electrical load, provides approximately 3,197MWh. The combined annual electrical consumption of the NTC operational buildings within the cluster is approximately 1,370MWh or around 43% of the total generated power. The combined annual electrical consumption of the non-NTC buildings within the cluster is approximately 12,787MWh, approximately 400% of the generated power. On this basis the assumption that all of the CHP generated power can be sold via private wire can be upheld, although lower system revenues based on electricity sale exclusively at export prices will be assessed in the interests of stress testing the proposals.

Table 23: Killingworth - System Cost Summary

System	Network Infrastructure costs (£)	Energy Centre & Plant costs (£)	Potential CO2 abatement (tonnes p/a)	Total costs (£)
Gas CHP & TU	1,460,692	561,355	947.48	**2,022,047**
Gas CHP biomass top-up	1,460,692	877,803	1,092.39	**2,338,495**

Table 24: Killingworth System Annual Income Profile

System Annual Income profile		
Income Item	**Gas CHP & TU (£)**	**Gas-Biomass (£)**
Energy Sales (Private Wire only)	£605,478	£605,478
Energy Sales (Export Only)	£373, 199	£373, 199
RHI Income	-	£33,451
Standing Charge	£33,052	£33,052
Business rates (Cost not income)	£26,290	£26,290

6.4.3 Network options – Financial Assessment:

A techno-economic analysis is presented for the Killingworth cluster for the following four technology options:

6. Gas CHP unit using private wire electrical distribution
7. Gas CHP unit with electricity exported to the national grid
8. Gas CHP unit plus biomass heat generation with private wire electrical distribution
9. Gas CHP unit plus biomass heat generation with electricity exported to the national grid

Table 25: Killingworth Cluster Summary Table

Killlingworth Cluster				
		Appraisal (years)	IRR	NPV @ 6%
Gas CHP Private Wire	Without TS	25	8%	452,933
		40	10%	904,094
	With TS	25	10%	794,793
		40	11%	1,332,117
Gas CHP Export	Without TS	25	-	-2,297,250
		40	-	-2,371,725
	With TS	25	-	-2,492,930
		40	-	-2,583,981
Gas CHP + Bio Private Wire	Without TS	25	8%	344,416
		40	9%	831,894
	With TS	25	9%	673,379
		40	10%	1,225,951
Gas CHP + Bio Export	Without TS	25	-	-2,405,768
		40	-	-2,443,925
	With TS	25	-	-2,614,345
		40	-	-2,690,146

Table 25 provides an overview of the financial performance of the four system options for the Killingworth network proposal at an assumed public sector borrowing rate of 6%. As the table identifies, neither of the export based systems return a positive NPV suggesting that they are not viable given the capital investment required.

However, based on a private wire electricity sale approach, both gas CHP & gas top-up and biomass backup system options would be viable at the 6% target rate. The Gas CHP & gas top-up approach returns a higher NPV over both the 25 and 40 year appraisal periods with a marginally greater IRR value across both periods despite the additional RHi tariff income received for the biomass top-up system.

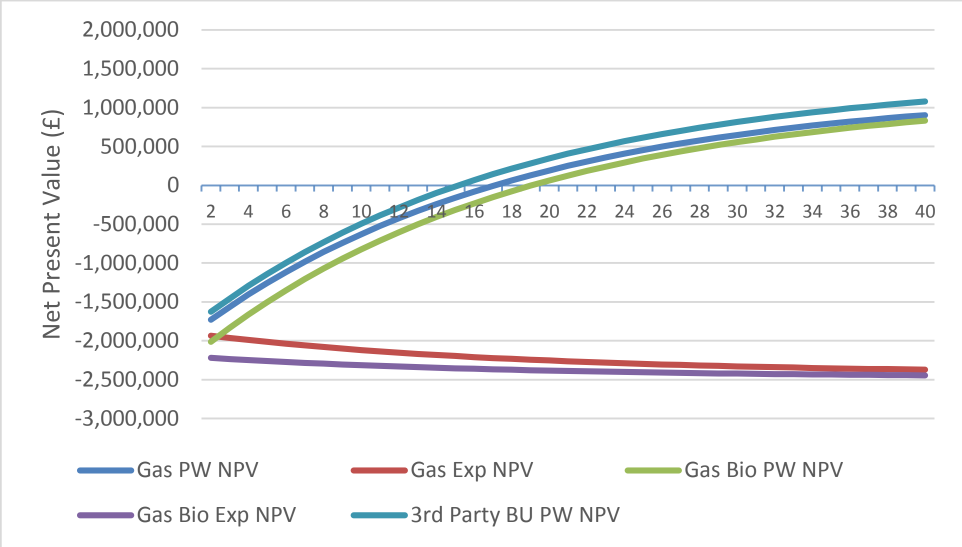


Figure 50: Killingworth Cluster – Modular CHP Outline Cost Evaluation (NPV discount rate @ 6%)

As the chart above (Figure 50) demonstrates, both private wire systems are net positive from year 17 onwards in the case of the gas CHP & gas top-up system, and year 19 onwards in the case of the gas-biomass, both systems having repaid the required capital outlay at this point. This suggests that the network would operate profitably from this stage onwards.

In the case of the gas CHP & gas top-up and the gas-biomass system under a grid-export approach a positive NPV is never obtained over the appraisal period of a maximum of 40 years.

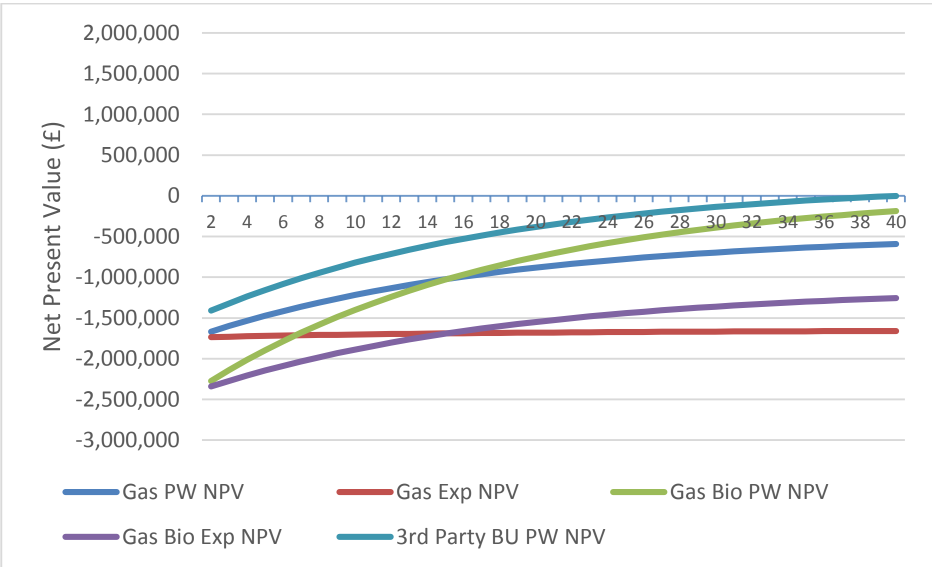


Figure 51: Killingworth Cluster – Base Load CHP Outline Cost Evaluation (NPV discount rate @ 6%)

The Base load CHP financial performance highlighted in Figure 51 identifies that positive NPV values are not achieved for any proposed system configurations at the 6% target rate. Highlighting that with a much lower volume of electricity to sell, as a result of the smaller CHP unit, there is insufficient revenue generated to recover the capital investment required.

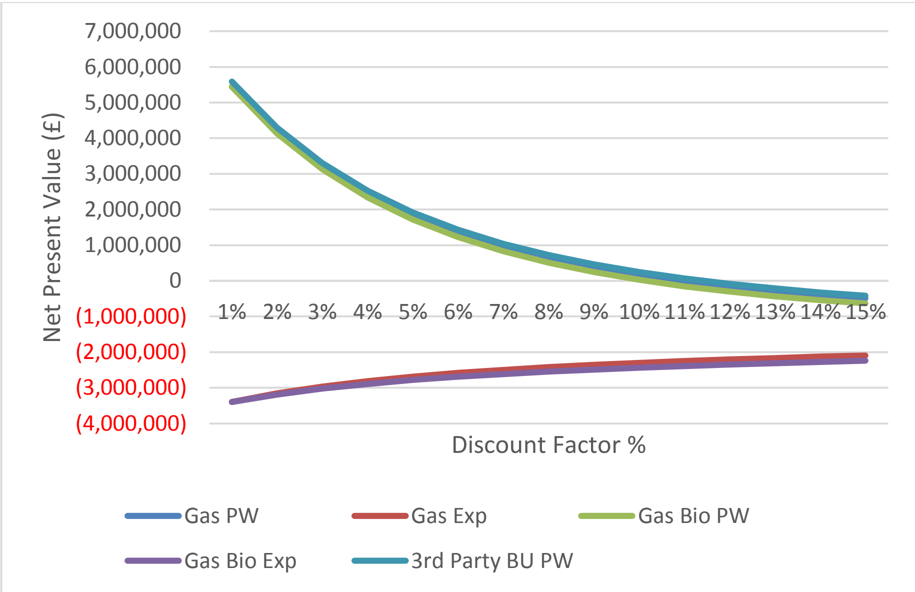


Figure 52: Killingworth Cluster – Modular CHP NPV DCF Sensitivity Analysis

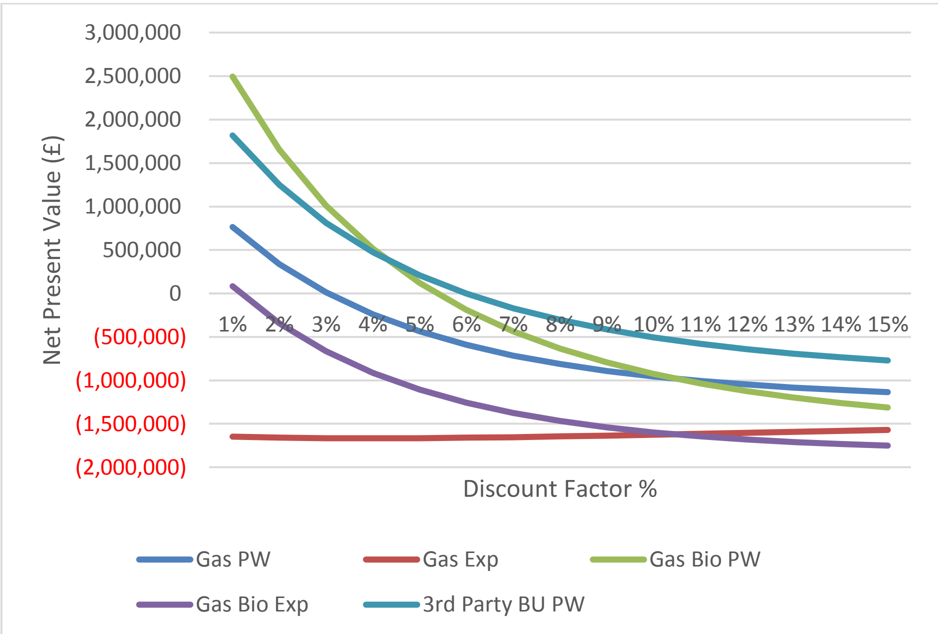


Figure 53: Killingworth Cluster – Base Load CHP NPV DCF Sensitivity Analysis

Figures 52 and 53 highlight the change in NPV for a given discount factor. In the case of the modular CHP approaches both private wire proposals just manage to return a positive NPV at a 10% discount factor, although in reality further cost reduction or small capital offset might be required to make these proposals an attractive prospect for private finance. A healthy return is provided at a 6% public borrowing rate. None of the export only configurations are able to meet requirements at a private or public rate.

In the case of the base load CHP approaches no configurations meet public or private finance requirements on either a private wire or export only configuration. The private wire biomass top-up and third party top-up configurations come closest as they just manage to return a positive NPV at around 5.5%.

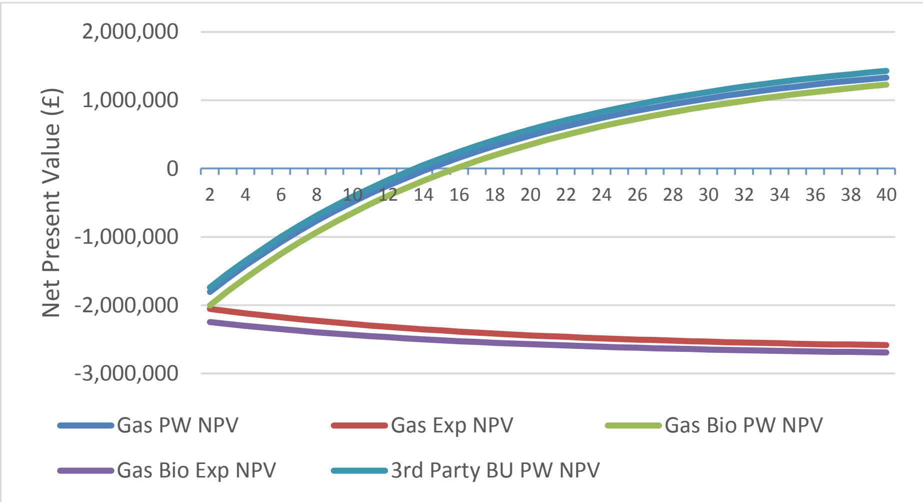


Figure 54: Killingworth Cluster Modular CHP with Thermal Store - Outline Cost Evaluation (NPV discount rate @ 6%)

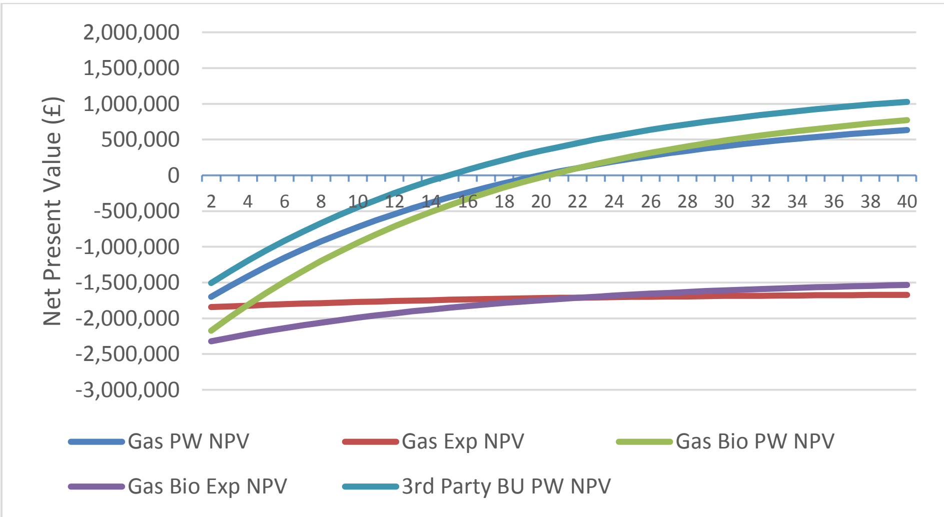


Figure 55: Killingworth Cluster Modular CHP with Thermal Store - Outline Cost Evaluation (NPV discount rate @ 6%)

Figure 54 identifies that the addition of a thermal store in the case of the modular CHP private wire system has a positive impact in terms of financial performance reducing the payback of both the gas-only and biomass top-up systems by just-under 3 years (17 years to 14 years). In the case of the export only systems neither modular CHP configurations is able to generate a positive NPV with the addition of a thermal store.

Figure 55 identifies that the addition of a thermal store to base load CHP private wire system has a dramatically positive impact. Where the non-store system was unable to return a positive NPV the same system with a thermal store becomes net positive from year 20 onwards for private wire configurations, although this is not possible for export only approaches.

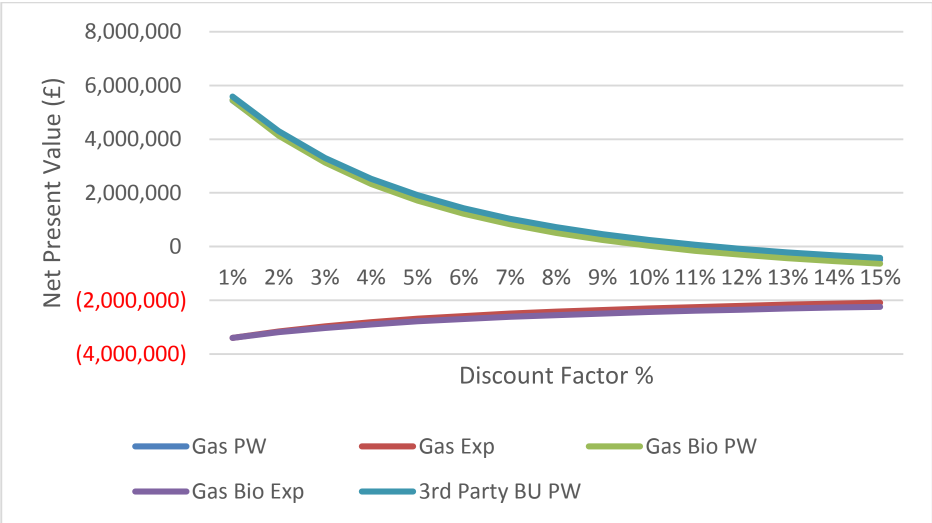


Figure 56: Killingworth Cluster Modular CHP with Thermal Store - NPV DCF Sensitivity Analysis

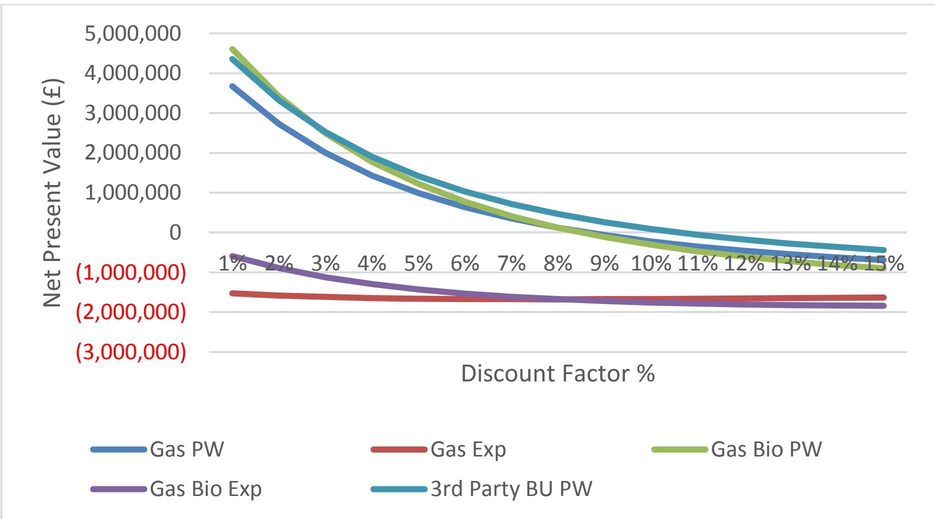


Figure 57: Killingworth Cluster Base Load CHP with Thermal Store - NPV DCF Sensitivity Analysis

Further to the NPV analysis, figures 56 and 57 demonstrate that for private wire systems, under a modular CHP approach, both gas and biomass thermal storage options meet the threshold requirements to attract private sector financing at 10%, as well as providing a healthy return at public borrowing rates. In the case of base load private wire systems, public borrowing requirements are easily met for thermal storage options, although performance falls just short of private lending requirements dropping into negative NPV at a discount rate of approximately 8%.

6.4.5 Proposal Evaluation – Summary:

The mix of anchor buildings within the proposal provides a positive influence in terms of diversity on the networks overall heat demand profile. Although five of the six anchor buildings are NTC sites the largest heat and power demands are provided by the Killingworth shopping centre signifying that their buy-in could be critical to the success of the network. The combined power demand from the NTC buildings accounts for approximately 43% of the system generated power, although the network would be reliant on the private wire sale of the remaining 57% of power to the shopping centre.

In terms of physical constraints there is little to cause real concern. A suitable site for the energy centre is available within the shared grounds of the high school and leisure centre. There are no land ownership constraints in term of proposed network routes and the majority of land surrounding the indicative network locations is within NTC ownership. Further to this as the satellite overhead image (figure 47) identifies the are significant amounts of green-space and associated soft-dig routes to reduce trenching costs.

In terms of financial viability table 25 demonstrates that whilst neither grid-export configurations are viable, both private wire options are viable both with and without thermal storage achieving a positive NPV and a range of IRR returns from 8-11% depending on technology/configuration across both the shorter 25 year, and longer 40 year appraisal period.

There is no gap-funding requirement for either of the private wire configurations, which combined with the investment returns identified above suggest that this is a financially robust proposal that would secure interest from both public and private sectors. Other than the reliance on commitment from the Killingworth Centre owner, the lack of any considerable physical or technical constraints suggest that this proposal would warrant further exploration at the feasibility stage.

6.4.6 Potential Phase 2 Network Extension to include Killingworth Moor Development:

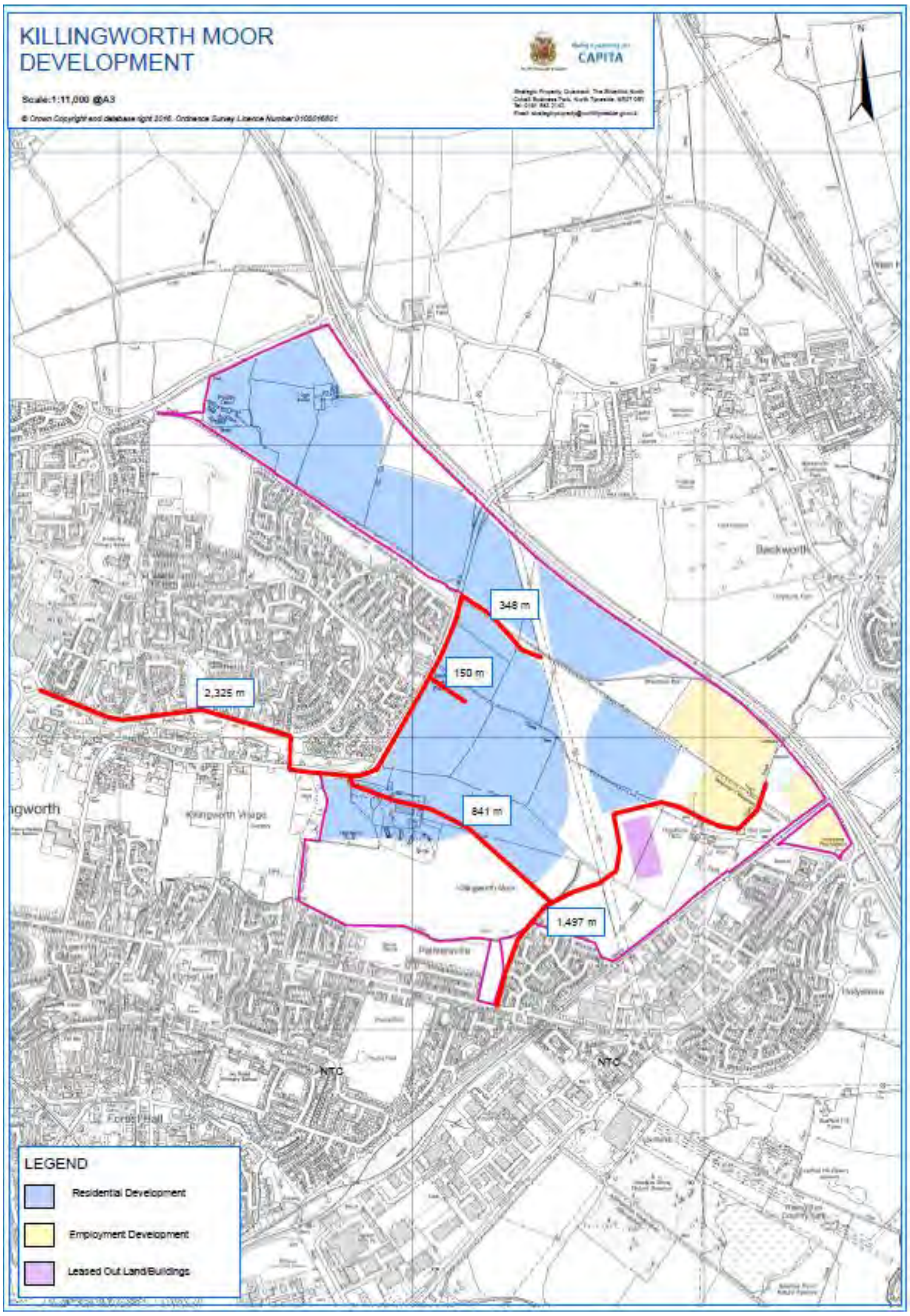


Figure 58: Indicative Murton Gap Network Extension


Figure 59: Killingworth Moor Indicative Masterplan

As the map provided in figure 58 identifies the proposed Killingworth Moor development lies approximately 1km to the East of the identified first phase of the Killingworth network proposal. Current proposals for the development include 2,000 new dwellings of various sizes, 7,660m2 of secondary education provision, approximately 1,204m2 of primary education provision, and 500m2 of retail provision. A land allocation of up to 17Ha of commercial provision has been made but as there is no detail on the actual likely footprint of this it has not been possible to take this into account at this stage. Whilst the indicative Masterplan (figure 59) suggests a streetscape has been established, this is only illustrative at this stage and no final decision on layout has been reached. As such no final allocation of dwelling numbers has been decided for the various housing development cells shaded blue in figure 58.

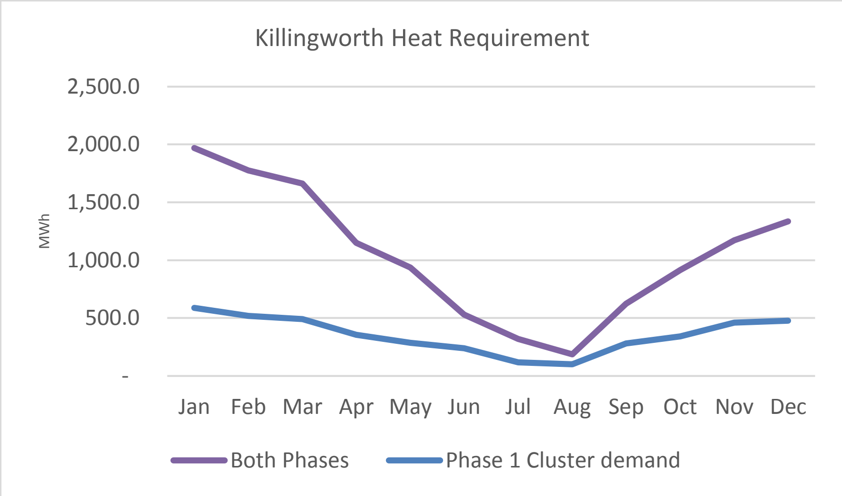


Figure 60: Phase 1&2 Heat Demand

With an additional heat demand of 12,550 MWh per annum the inclusion of the Killingworth Moor development represents a considerable extension to the initial system with an almost four-fold increase in the amount heat delivered annually from 4,382MWh to 16,932 MWh (figure 60). To service this additional demand a further 2.43 MWt of CHP capacity would be required along with an additional 2.74 MWt of top-up boiler capacity, bringing the combined thermal capacity of the larger system to approximately 6.7 MWt, roughly a 450% increase over the initial 1.5 MWt combined capacity. The further 2.6 MWe capacity provided would generate approximately 350% more power per annum at 11,113 MWh in comparison to the initial 3,196 MWh per annum.

Table 26: Phase 1&2 Network Detail

Element		Phase 1	Phase 2	Additional	% Increase
Plant	CHP Thermal capacity (MWt)	820 (kWt)	3.25	2.43	396
	CHP Electrical capacity (MWt)	630 (kWe)	3.2	2.6	508
	Top-up boiler capacity (MWt)	800 (kWt)	3.44	2.74	430
	MWh annual heat delivered (MWh)	6,827	24,449	17,622	360
	MWh annual power generated (MWh)	4,381.6	16,931.8	12,550	386
Network Infrastructure	Transmission Mains (m)	1,203	5,523	4,320	459
	Distribution Mains (m)	279	12,279	12,000	4,400
	Energy Centre Footprint (m2)	152	669	517	440

Considerable additional network infrastructure would also be required (Table 26). A further 4,320m in the case of the transmission infrastructure, which would be a greater than four-fold increase over the 1,203m specified for the initial system. The largest increase in infrastructure terms would result from the additional distribution mains required to service each individual dwelling. As final siting plans are not yet available it is not possible to cost this accurately, in absence of this an allowance of 6m per dwelling has been made (2,000 units). On this basis an additional 12,000m of distribution mains will be required, representing an approximate 4,400% increase over the initial system specification. As further detail emerges it will be possible to revisit this, but in absence of this detail we are constrained to the assumptions made. The additional plant requirement will naturally have an associated impact on the size of the Energy Centre required. To serve the larger network an additional 517m2 will be required to accommodate a the larger 669m2 Energy Centre, in comparison to the 152m2 building required for the smaller network. At 3,000m2 the site currently proposed would still comfortably accommodate the larger Energy Centre along with any ancillary equipment.

Table 27: Phase 1&2 Network Cost Detail

Element		Phase 1	Phase 2	Additional	% Increase
CAPEX	Transmission Mains (£)	1,183,752	5,434,632	4,250,880	425
	Distribution Mains (£)	167,400	7,367,400	7,200,000	4,400
	Total Network Costs (£)	1,460,692	13,335,326	11,764,634	905
	Energy Centre & Plant (£)	561,355	2,333,182	1,771,827	451
	Total CAPEX (£)	2,022,047	15,558,507	13,536,460	769
OPEX	Direct Energy & Overhead costs (£)	439,162	1,439,718	1,000,556	327
Income	Gross Income (£)	638,531	2,223,433	1,584,902	348
	Net Income (£)	199,369	783,715	584,346	393

Given the extent of the physical extension to the network there are also considerable CAPEX implications as a result. The additional £4.25m cost in terms of transmission mains above the initial £1.18m requirement represents a fourfold increase in capital cost. Although the additional £7.2m capital requirement for the distribution mains would dwarf the initial capital cost of £167,000, representing an increase of over 4,400%. including the additional £1.77m capital requirement for the Energy Centre, the total capital cost for both network phases rises considerably from £2.02m for the initial phase to £15.56m for both phases, an increase of approximately 770%.

Correspondingly the increase in annual OPEX costs including both additional direct input energy costs and network operating overheads is significant at a total of approximately £1.44m per annum for both phases compared to £439k per annum in the initial phase.

Conversely, the resulting increase in system net income is just under 400% at approximately £784k per annum compared to £199k per annum in the case of the initial phase.

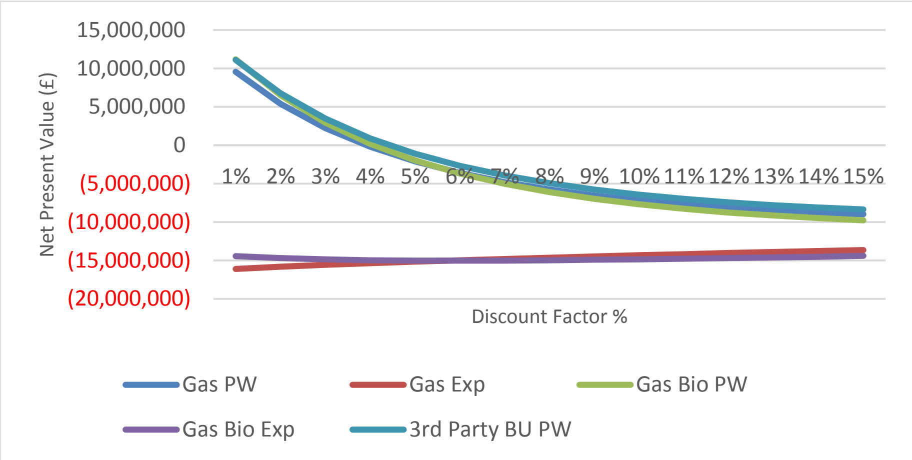


Figure 61: Phase 1&2 Financial Performance

The conclusion to be drawn from this is that the increase in net income at under 400% is insufficient to accommodate the combination of a considerable 770% increase in CAPEX costs along with the 330% increase in OPEX costs. This effect is reflected in the financial performance metrics. Whilst the first phase of the network is able to recover the initial capital investment in approximately 17 years, returning a positive NPV £904k at a public sector borrowing rate of 6%. The larger network incorporating both phases can only return a positive NPV of £2.25m at a 3% borrowing rate (figure 61), which indicates that without significant capital offset the proposal would not be likely to meet either private sector or public sector investment requirements.

On this basis the second phase expansion of the network to include the proposed Killingworth Moor new development does not seem viable. However, in many ways, given the level of final detail still outstanding regarding the new development, it is too soon to draw this conclusion. The considerable majority of the increased capital cost is incurred by the additional distribution mains required to service each individual dwelling, an additional £7.2m of cost which is not offset by the additional £584k in net income. As highlighted earlier, without the final siting plans for these dwellings, we can only use an indicative 6m of distribution mains per dwelling to derive the associated capital cost. This assumption could be excessive, however in absence of final detail it is not possible to provide a more accurate calculation. Further to this there could also be value engineering opportunities such as passing this additional £7.2m cost onto the development consortium therefore removing the cost burden from the financial model. However, at this stage, without an indicative commitment from the developer, this would introduce an excessive level of optimism-bias into the financial model which cannot be justified.

Whilst we have been able to provide a high-level assessment of the network opportunity posed by the Killingworth Moor development, given the outstanding detail it is not possible at this stage to carry out a complete analysis. A full analysis can only be undertaken at later stages once the final detail has been made available, although the initial modelling outputs are provided as an addendum to the modelling supplement. As such we advise that the larger Killingworth network proposal (incorporating both phases) is not included in the overall evaluation of the six network proposals in this report as it not possible to assess the opportunity to a consistent level of detail as that presented for the other network proposals.

6.5 North Shields System proposal

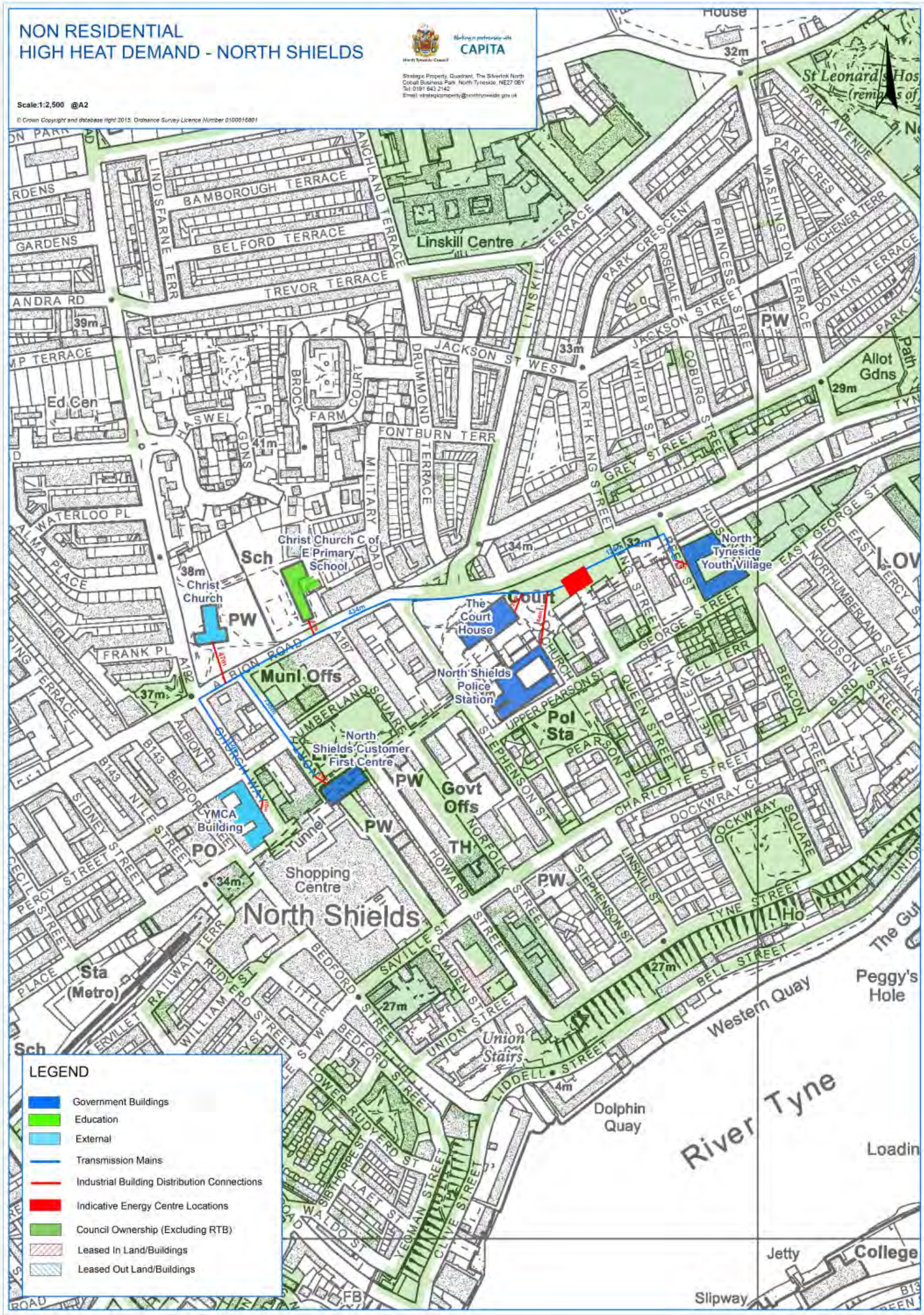
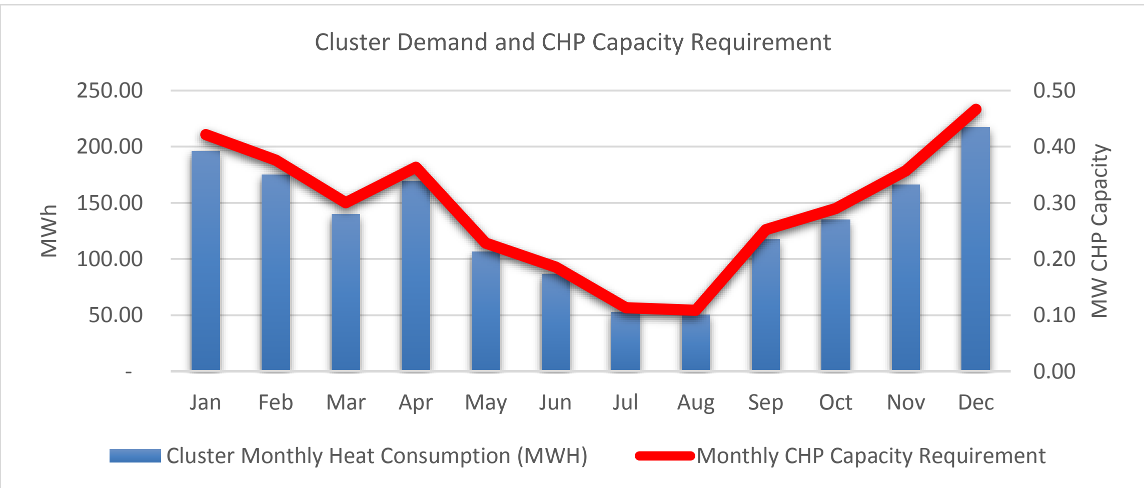


Figure 62: North Shields System proposal map

6.5.1 North Shields System – Anchor Buildings and Energy Centre Location

Table 28: North Shields - Anchor Building Properties

Building	Size m2	Annual Heat demand (MWh)	Annual Power demand (MWh)	Annual Cooling demand (MWh)	Data Source	Comments
Christ Church Primary School	1,030	137	57	n/a	Actual consumption data from NTC EM System	Older small Primary school with lower summer baseload & no heating load from June to September
NT Magistrates Court	2,862	286	162	29	Actual consumption data from NTC EM System	Large district court with no heating load in July & August. Continuous DHW demand
NS Police Station	2,916	409	175	n/a	Modelled on CIBSE TM46 benchmark using GIS measurement	Large town centre Police station with no heating load in July & August. Continuous DHW demand
NTC Youth Village	1,777	95	150	n/a	Actual consumption data from NTC EM System	Large mixed-use local Authority building with no heating load in July & August
YMCA Building	2,904	408	232	29	Modelled on CIBSE TM46 benchmark using GIS measurement	Large mixed-use public access building with extended opening hours with no heating load in July & August
NTC Central Library	2,621	268	212	26	Actual consumption data from NTC EM System	Large mixed-use customer service centre and library with extended opening hours. No Heating load in July & August but continuous DHW demand
Christ Church	1,031	87	21	n/a	Modelled on CIBSE TM46 benchmark using GIS measurement	Large historical stone-built structure with high heat loss, and high steady heat demand – assumed no heating load in July & August



The North Shields cluster includes a relatively diverse range of buildings (table 28). With just the one school the cluster is less affected by seasonality with heat demand relatively constant across ten months of the year, with a noticeable drop in demand in July and August. The higher demands are provided by North Tyneside Magistrates Court, the North Shields Police station, and the YMCA building, and, although the Magistrates court sits within the NTC Corporate energy contract, all of these buildings are external to the Council and the network is dependent on their long-term commitment as anchor buildings.

Four of the seven buildings within the cluster are NTC operational buildings with actual consumption data available, with the remaining three buildings reliant on benchmark modelled data, two of these buildings would be significant anchors within the network so further attention at the feasibility stage will be required to test the benchmark outputs.

Figure 63: North Shields - Aerial Satellite View

As identified on the proposal map (Figure 62) a good amount of the land within the town centre is not within NTC ownership and, whilst does not affect the key buildings within the centre of the cluster, the lack of land ownership to the West of the cluster could affect a number of anchor buildings where the indicative network routes run through non-NTC owned land in order to connect buildings. In addition to land ownership constraints the satellite image above highlights a shortage of green space in some areas which limits flexibility around network routing and associated opportunities to keep network infrastructure costs down.

6.2.2 Energy Centre Location – Justification & Rationalisation

The satellite image below (Figure 64) identifies a site immediately north-east of the Magistrates Court building of approximately 1,000m2 that is within NTC ownership, and could comfortably accommodate the largest 85m2 energy centre requirement along any additional requirement for biomass or thermal storage. Whilst the apparent green-field appearance of the site should be beneficial in terms of development costs, a further check should be undertaken at feasibility stage to ensure the site is not encumbered by any open space or village green constraints. Although the site is not centrally located within the cluster, given the land ownership constraints within the immediate area, along with the general constraints of a location such as this within an established town centre, this is the only suitable site available within reasonable proximity to the proposed network.

Further assessment of proposed Energy Centre sites; including; Air Quality Assessment, Noise Disturbance Assessment, Visual Impact Assessment, and Planning Risk, will be undertaken at subsequent stages.

Figure 64: North Shields - Aerial Satellite View (2)

The NTC Asset Management and NTC Energy Management function have confirmed that the three NTC operational buildings within the cluster are heated by traditional medium temperature wet heating systems operating at approximately 80°C flow with 70°C return. Domestic hot water is supplied by with calorifiers operating at 60°C flow and 50°C return. Further detail on the non-NTC buildings will have to be sought at the feasibility stage however, a review of satellite images has not identified any potential constraints such as roof top plant rooms, and the age of buildings suggests that traditional wet heating systems are in use. On this basis it is assumed that all buildings are suitable for connection to a district heating network and that none of the buildings identified present insurmountable constraints in terms of the proposal.

6.5.2 System configuration and Technology Options:

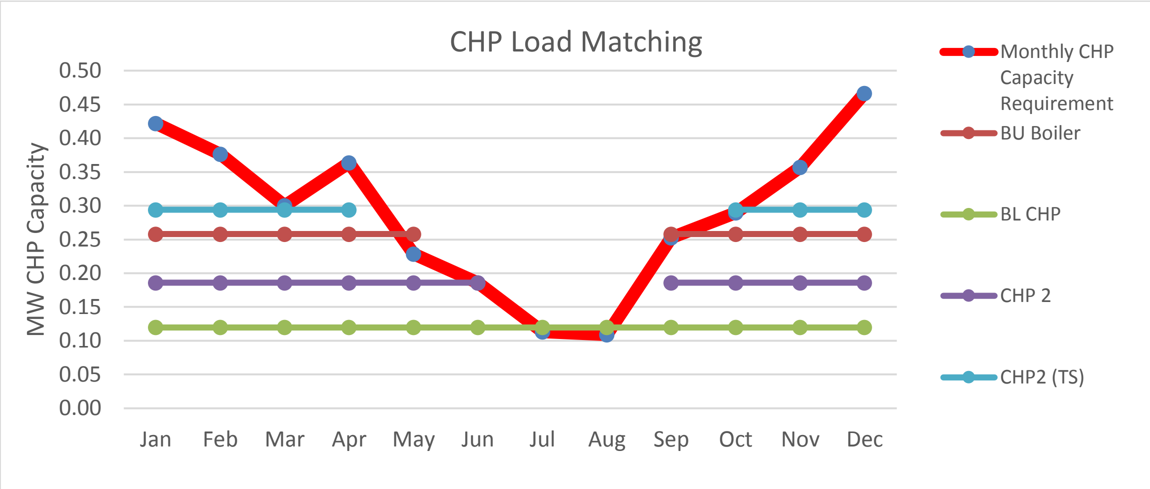


Figure 65: North Shields - Monthly Heat Demand & CHP Capacity Requirement

With a summer base-load demand of 50 MWh in August sizing a gas CHP unit according to the base-load demand would dictate a maximum CHP size of 120kWt/94kWe, with a top-up boiler capacity requirement of 570kWt for gas fired boilers, or 620kWt for Biomass boilers (figure 65). On a base-load CHP sizing basis only 38% of the annual heat demand would be served by the CHP unit with the remainder being provided by the back-up boilers.

Following a modular CHP approach, the smaller base-load CHP unit could be supported a larger 190kWt/145kWe CHP unit to provide a combined capacity of 310kWt/240kWe which would provide approximately 84% of the annual heat demand and reducing back-up boiler capacity requirement to 3000kWt for gas fired boilers, or 330kWt for Biomass boilers. Further to this the modular CHP approach would generate an additional 649 MWh of power for sale via private wire, or export.

For both the gas CHP & gas top-up, and Biomass system options electricity sale via a private-wire only, and export only approach has been modelled to assess establish the value of the two different approaches.

Network infrastructure costs to connect the North Shields anchor buildings total £955,850. Of this 830m of transmission mains are required at a cost of £816,720, with a further 189m of distribution mains at a cost of £113,400, and a total cost of £40,649 for building connections.

Total capital costs for the gas CHP & gas top-up network including network infrastructure, plant and energy centre costs come to £1,439,993. Whereas the total cost for the biomass top-up system comes is higher at £1,576,798 due to the higher cost of biomass heating plant and ancillary equipment (table 29).

With a combined volume of 58.67m3 the network transmission mains provide an inherent storage capacity of approximately 2.67MWh, or the equivalent system run time of 5.26 hours. An additional capacity of 57m3 has been specified for the modular CHP thermal storage model providing an additional 2.6MWh of storage at a cost of £47,848, the same vessel has been specified for the single CHP thermal storage model as this provides the closest fit to the cluster demand profile.

Annual power generation for the larger modular CHP configuration, once adjusted for network parasitic electrical load, provides approximately 1,163MWh. The combined annual electrical consumption of the NTC operational buildings within the cluster is approximately 729.26MWh or around 63% of the total generated power. The combined annual electrical consumption of the non-NTC buildings within the cluster is approximately 428MWh, approximately 38% of the generated power. On this basis the assumption that all of the CHP generated power can be sold via private wire can be upheld, although lower system revenues based on electricity sale exclusively at export prices will be assessed in the interests of stress testing the proposals.

Table 29: North Shields - System Cost Summary

System	Network Infrastructure costs (£)	Energy Centre & Plant costs (£)	Potential CO2 abatement (tonnes p/a)	Total cost (£)
Gas CHP & TU	970,769	209,681	350	1,180,450
Gas CHP biomass top-up	970,769	326,474	409	1,297,243

Table 30: North Shields System Annual Income Profile

System Annual Income profile		
Income Item	**Gas CHP & TU (£)**	**Gas-Biomass (£)**
Energy Sales (Private Wire only)	224,572	224,572
Energy Sales (Export Only)	137,696	137,696
RHI Income	-	13,562
Standing Charge	11,365	11,365
Business rates (Cost not income)	9,756	9,756

6.5.3 Network options - Financial assessment

A techno-economic analysis is presented for the North Shields cluster for the following four technology options:

1. Gas CHP unit using private wire electrical distribution
2. Gas CHP unit with electricity exported to the national grid
3. Gas CHP unit plus biomass heat generation with private wire electrical distribution
4. Gas CHP unit plus biomass heat generation with electricity exported to the national grid

Table 31: North Shields Cluster Summary Table

North Shields Cluster				
		Appraisal (years)	IRR	NPV @ 6%
Gas CHP Private Wire	Without TS	25	3%	-273,814
		40	5%	-113,301
	With TS	25	6%	-42,186
		40	7%	73,684
Gas CHP Export	Without TS	25	-	-1,278,739
		40	-	-1,310,295
	With TS	25	-	-1,431,313
		40	-	-1,485,320
Gas CHP + Bio Private Wire	Without TS	25	3%	-306,959
		40	5%	-131,723
	With TS	25	5%	-70,113
		40	7%	46,667
Gas CHP + Bio Export	Without TS	25	-	-1,311,884
		40	-	-1,328,717
	With TS	25	-	-1,459,240
		40	-	-1,512,338

Table 31 provides an overview of the financial performance of the four system options for the North Shields network proposal at an assumed public sector borrowing rate of 6%.

It is clear from the table that very few of the technology options produce a positive NPV. This is true of all but the thermal storage options in each of the proposed configurations.

The best performing system yields an IRR of 7% which is visible against the Gas CHP & gas top-up modular CHP system with thermal store when appraised over a 40 year period. Even at the lower public sector borrowing rate of 6% a positive NPV of only £169,307 is returned.

This suggests that the only situation in which this network could become viable is one in which capital costs could be reduced significantly, or if the council were able to provide a considerable capital injection into the scheme.

In the case of the each of the export configurations, no positive IRR figures are obtained. This indicates that the likelihood of obtaining public or private sector finance is extremely limited for this proposal.

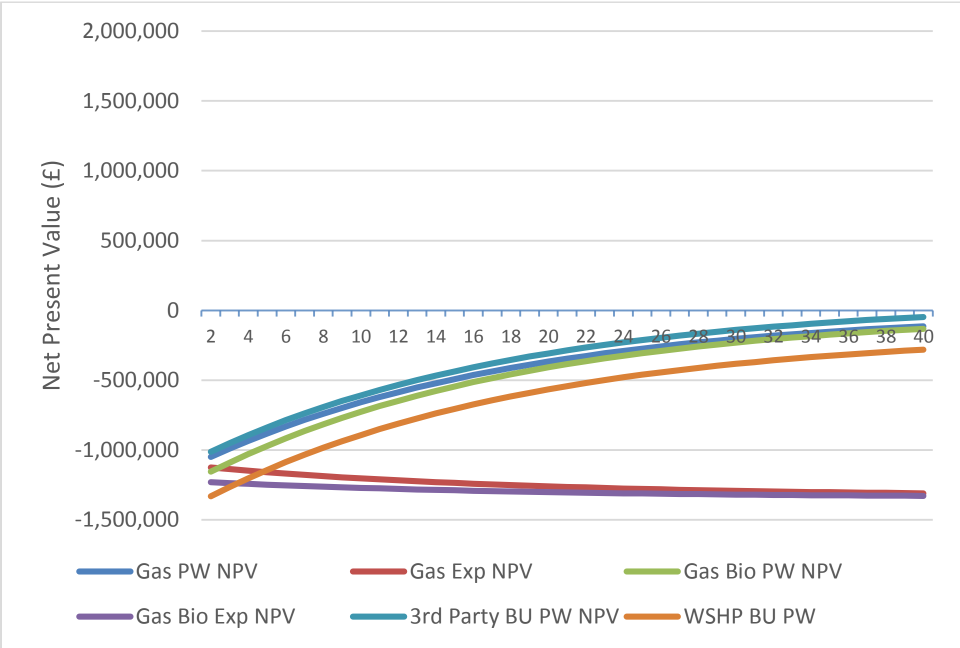


Figure 66: North Shields Cluster – Modular CHP Outline Cost Evaluation (NPV discount rate @ 6%)

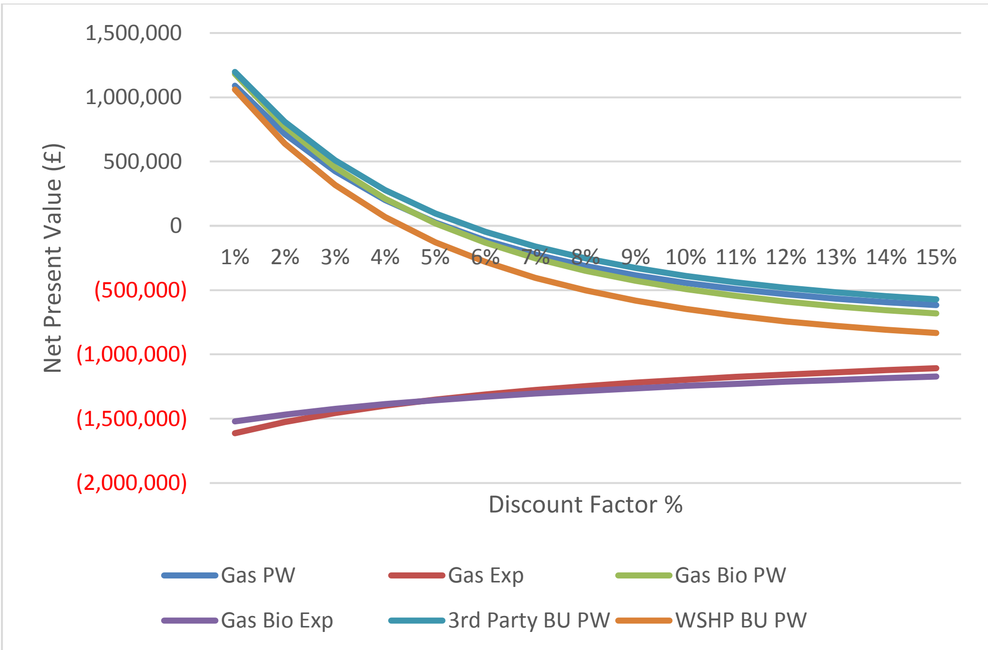


Figure 67: North Shields Cluster – Modular CHP NPV DCF Sensitivity Analysis

As the figures 66 and 67 demonstrate, the only viable North Shields network options would be the modular CHP private wire systems at a financing rate of approximately 5%. As highlighted previously it is unlikely that this would be considered financially viable even at preferable public sector borrowing rates. Figure 68 demonstrates a similarly challenging situation with regards to the financial performance of the base load CHP system approach.

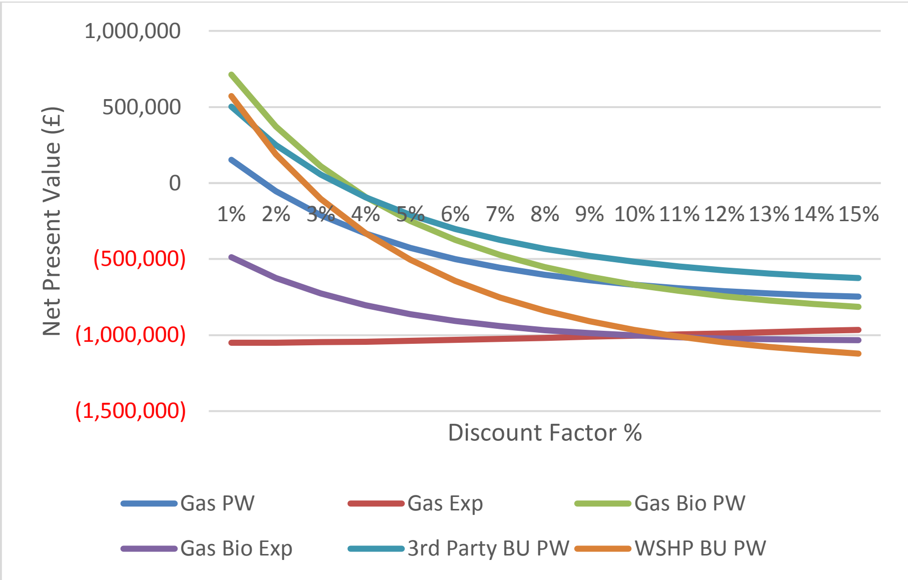


Figure 68: North Shields Cluster – Base Load CHP NPV DCF Sensitivity Analysis

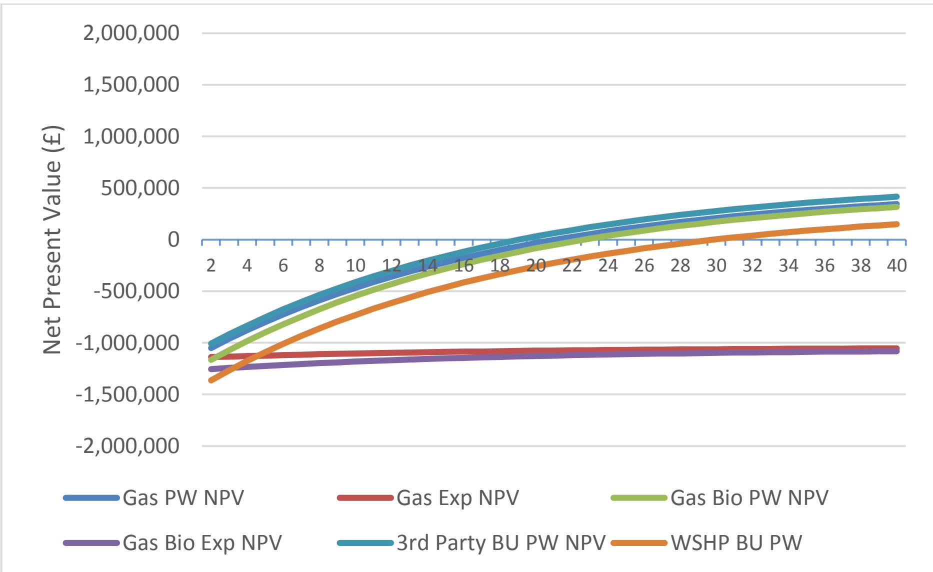


Figure 69: North Shields Cluster - Modular CHP with Thermal Store Outline Cost Evaluation (NPV discount rate @ 6%)

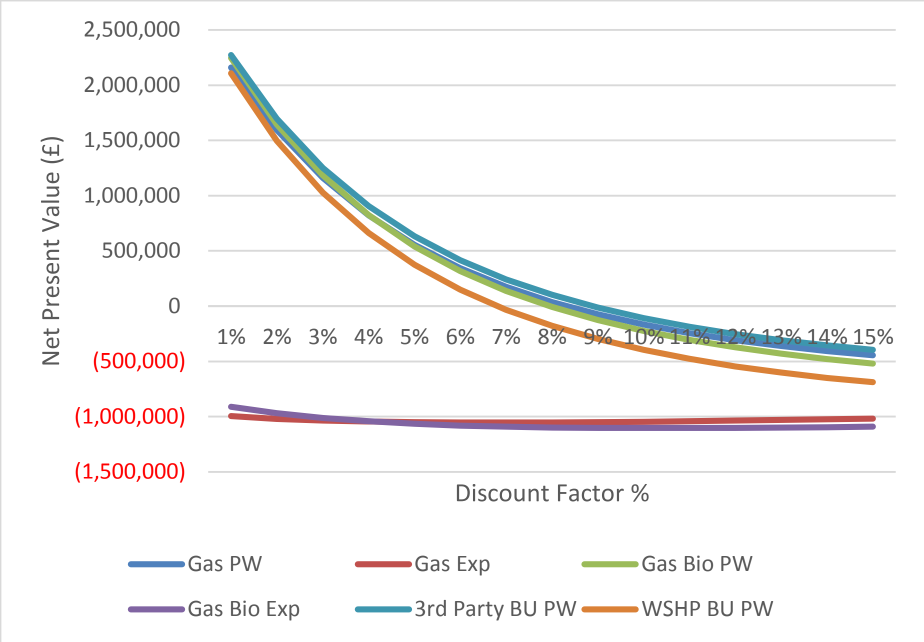


Figure 70: North Shields Cluster - Modular CHP with Thermal Store NPV DCF Sensitivity Analysis

Figure's 69 and 70 both highlight that positive impact of the addition of a thermal store to financial performance of the modular CHP configurations under a private wire approach. Although proposals still fail to meet private financing thresholds, a positive NPV can be achieved for private wire configurations from around year 22 onwards. Further cost reduction of capital offset will improve this scenario.

As the financial analysis has demonstrated the North Shields network proposal does not appear to be financially viable in its current form. As the appraisal methods demonstrate there is insufficient income within the proposal to offset the capital outlay required under many of the network scenarios. Considerable value engineering or significantly higher energy pricing would be required to make this a viable proposal over the 25 and 40 year appraisal periods.

6.5.4 Proposal Evaluation – Summary:

The level of heat demand diversity is a positive factor across the North Shield cluster with reduced seasonality and a longer daily operating cycle provided by buildings like the Police station, the NTC Central library, and the YMCA building. Three of the seven anchors within the cluster are non-NTC buildings and therefore reliant on benchmark modelled consumption data at this stage. Two of these buildings, the Police station, and the YMCA building would be significant anchors within the network so the associated load risk must be taken into account. In terms of system generated power the combined demand of the NTC buildings accounts for approximately 63% of the total generated power, and whilst there is sufficient demand for the remaining power from the non-NTC buildings, this proposal is reliant on their buy-in.

In terms of physical constraints, whilst a suitable site exists for the energy centre it has not been possible to centrally locate the centre within the proposal area. The proposal map (figure 62) highlights that there are a number of land ownership constraints within the proposal area.

Whilst the land ownership constraints are not prohibitive, as network mains can still be located in the highway, there are limited opportunities to optimise routes, and an element of existing utilities congestion should be expected given the age of the built environment in the town centre. As the satellite overhead image in figure 63 demonstrates, soft-dig opportunities are limited in much of the proposal area.

In terms of financial viability neither of the grid-export scenarios have proven to be viable under the evaluation criteria generating an NPV that is higher in most cases than the initial capital outlay suggesting that these scenarios would not be viable if reliant on the lower export based power revenues. The two private wire scenarios are only able to generate a positive NPV over the longer 40 year assessment period with the gas CHP & gas top-up modular system with thermal storage achieving a slightly higher value at £169,307, than the equivalent biomass top-up system which achieves an NPV of £142,290 (table 31). Neither of these private wire configurations achieve capital payback until year 23.

Whilst both of these proposals are able to achieve a positive return at the lower 6% target public financing rate, capital gap funding of around 30% (between £365k to £375k) would be required to achieve a positive NPV at the higher 10% private financing rate.

In terms of overall viability, whilst private wire configurations are feasible at lower public borrowing rates, both options are a good way off being sufficiently robust enough to meet private borrowing requirements. The level of gap funding needed to meet the private requirements is unlikely to be achieved based on the strength of this proposal. Further to this there are risks around the dependence on external buy in, along with physical constraints resulting from the built environment within the proposal area. With all these factors considered the North Shields proposal does not appear to be sufficiently robust to warrant further exploration at the feasibility stage.

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6.6 Wallsend System proposal

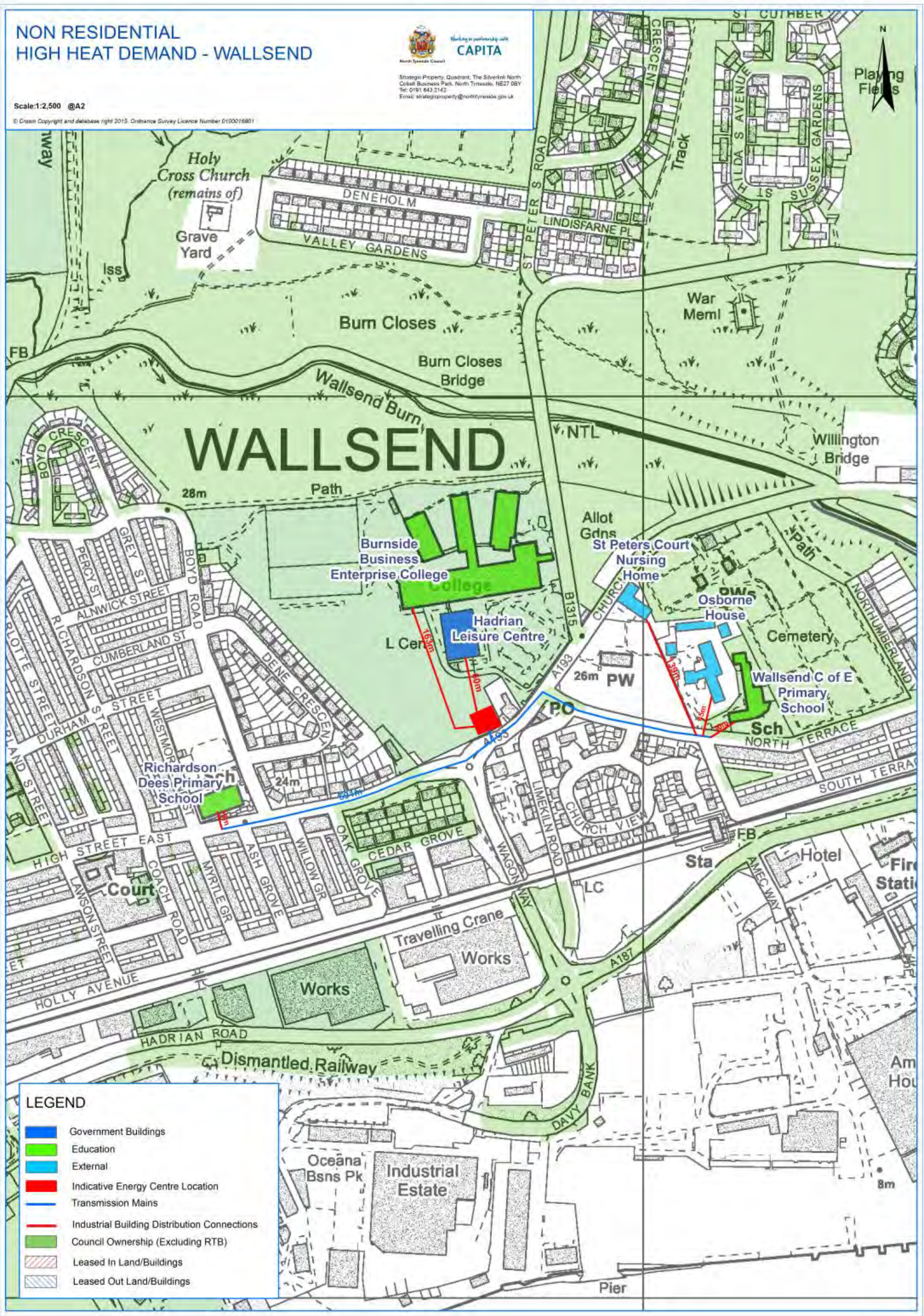

Figure 71: Wallsend System proposal map

6.6.1 Wallsend System – Anchor Buildings and Energy Centre Location

Table 32: Wallsend - Anchor Building Properties:

Building	Size m2	Annual Heat demand (MWh)	Annual Heat demand (MWh)	Annual Cooling demand (MWh)	Data Source	Comments
Burnside High School	12,825	2,891	584	128	Actual consumption data from NTC EM System	Large modern Secondary school with lower summer base-load & no heating load from June to September
Wallsend St Peters C of E Primary School	1,232	135	66	n/a	Actual consumption data from NTC EM System	Smaller relatively modern (mid-80's) Primary school with lower summer base-load & no heating load from June to September
Richardson Dees Primary School	1,932	252	71	n/a	Actual consumption data from NTC EM System	Medium sized Victorian Primary School with considerable demand given the size of building. Lower summer base-load & no heating load from June to September
St Peters Court	1,703	572	128	n/a	Modelled on CIBSE TM46 benchmark using GIS measurement	Residential elderly care home with continuous heat and DHW demand
Osborne House	4,812	1,617	361	n/a	Actual consumption data from NTC EM System	Residential elderly care home with continuous heat and DHW demand
Hadrian leisure Centre	2,580	1,518	658	26	Actual consumption data from NTC EM System	Modern wet leisure centre with high DHW demand and fairly constant seasonal load profile.

The Wallsend cluster includes some diversity in terms of anchor buildings. The three schools within the cluster introduce noticeable seasonality into the heat demand profile with a noticeable drop in demand in June and August as highlighted by the figure 72. Despite this seasonality, significant demand is provided by the large secondary school, and the seasonality is offset to an extent by an adjacent wet leisure centre with fairly constant year round demand which serves to raise the base load to the benefit of CHP sizing.

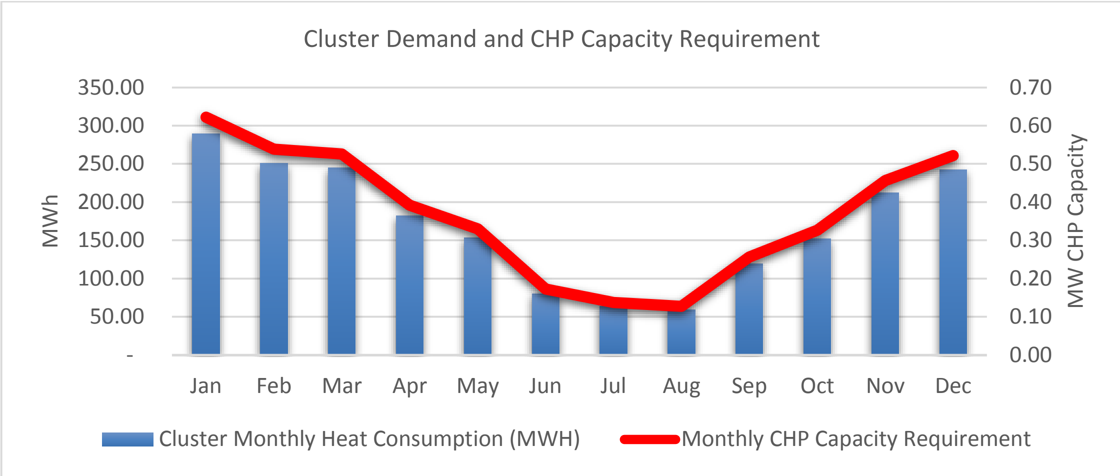

Figure 72: Wallsend - Monthly Heat Demand & CHP Capacity Requirement

Four of the six buildings within the cluster are NTC operational buildings with actual consumption data available, with only one building reliant on benchmark modelled data, providing a good overall level of confidence in the input data used to assess the district heating opportunity (table 32).

Figure 73: Wallsend - Aerial Satellite View

As the proposal map (figure 71) identifies there is a mixed level of NTC landownership within the immediate area a good amount of the land within the town centre is not within NTC ownership, whereas much of the land to the East is within ownership. Whilst this does not affect some buildings, other buildings, such the two care homes, and Richardson Dees primary can only be accessed via non-NTC land in order to connect these buildings. In addition to land ownership constraints the above image (figure 73) demonstrates a lack of soft-dig opportunities to reduce network infrastructure costs.

6.6.2 Energy Centre Location – Justification & Rationalisation

The satellite image below (figure 74) identifies a site immediately south of the Leisure centre building of approximately 1,000m2 that is within NTC ownership, and could comfortably accommodate maximum energy centre requirement of 130m2 along with any additional requirement for biomass or thermal storage. Whilst the site is within NTC ownership it is currently leased out to the schools PFI operator. Consultation with NTC's property services function has indicated that the proposed location for the energy centre is unlikely to present any challenges under the existing lease. NTC operate their leisure centre from within the leased out area under concession, the energy centre could be accommodated via an extension to that concession.

Further assessment of proposed Energy Centre sites; including; Air Quality Assessment, Noise Disturbance Assessment, Visual Impact Assessment, and Planning Risk, will be undertaken at subsequent stages.

Figure 74: Wallsend - Aerial Satellite View (2)

The NTC Asset Management and NTC Energy Management function have confirmed that the NTC operational buildings within the cluster are heated by traditional medium temperature wet heating systems operating at approximately 80°C flow with 70°C return. Domestic hot water is supplied by with calorifiers operating at 60°C flow and 50°C return. Although recently refurbished, the forum shopping centre and adjoining Wallsend Customer Service centre are still served by a traditional central boiler setup operating to 80°C flow with 70°C return, with domestic hot water calorifiers operating on similar parameters to the NTC operational buildings. On this basis it is assumed that all buildings are suitable for connection to a district heating network and that none of the buildings identified present insurmountable constraints in terms of the proposal.

6.6.3 System configuration and Technology Options

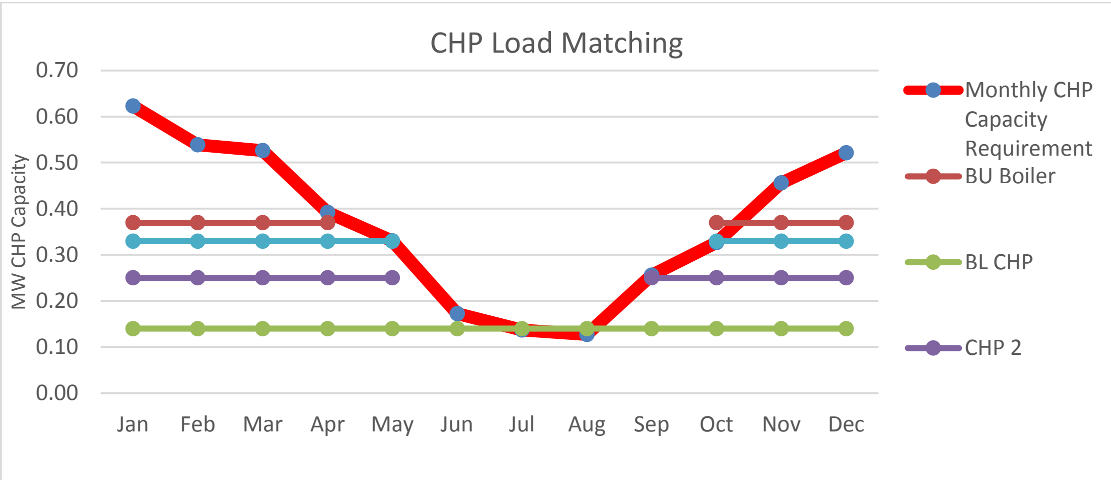

Figure 75: Wallsend - Monthly CHP Capacity Requirement & CHP Load Matching

With a summer base-load demand of 59.2 MWh in August (figure 75) sizing a gas CHP units according to the base-load demand would dictate a maximum CHP size of 140kWt/110kWe, with a top-up boiler capacity requirement of 790kWt for gas fired boilers, or 860kWt for Biomass boilers (figure 75). On a base-load CHP sizing basis only 35% of the annual heat demand would be served by the CHP unit with the remainder being provided by the back-up boilers.

Following a modular CHP approach, the smaller base-load CHP unit could be supported a larger 250kWt/195kWe CHP unit to provide a combined capacity of 390kWt/300kWe which would provide approximately 83% of the annual heat demand and reducing back-up boiler capacity requirement to 370kWt for gas fired boilers, or 400kWt for Biomass boilers. Further to this the modular CHP approach would generate an additional 899 MWh of power for sale via private wire, or export.

For both the gas-only, and gas-biomass system options electricity sale via a private-wire only, and export only approaches have been modelled to assess establish the value of the different approaches.

Network infrastructure costs to connect the Wallsend anchor buildings total £908,325. Of this 591m of transmission mains are required at a cost of £581,544 with a further 456m of distribution mains at a cost of £273,600, and a total of £53,182 for building connections.

Total capital costs for the gas CHP & gas top-up network including network infrastructure, plant and energy centre costs come to £1,104,610. Whereas the total cost for the biomass top-up system comes is higher at £1,443,859 due to the higher cost of biomass heating plant and ancillary equipment (table 33).

With a combined volume of 48.7m3 the network transmission mains provide an inherent storage capacity of approximately 1.9MWh, or the equivalent system run time of 2.94 hours. An additional capacity of 58m3 has been specified for the modular CHP thermal storage model providing an additional 2.6MWh of storage at a cost of £48,885, the same vessel has been specified for the single CHP thermal storage model as this provides the closest fit to the cluster demand profile.

Annual power generation for the larger modular CHP configuration, once adjusted for network parasitic electrical load, provides approximately 1,499MWh. The combined annual electrical consumption of the NTC operational buildings within the cluster is approximately 1,379MWh or around 92% of the total generated power. The combined annual electrical consumption of the non-NTC buildings within the cluster is approximately 488MWh, approximately 33% of the generated power. On this basis the assumption that all of the CHP generated power can be sold via private wire can be upheld, although lower system revenues based on electricity sale exclusively at export prices will be assessed in the interests of stress testing the proposals.

Table 33: Wallsend - System Cost Summary

System	Network Infrastructure costs (£)	Energy Centre & Plant costs (£)	Potential CO2 abatement (tonnes p/a)	Total cost (£)
Gas CHP & TU	908,325	196,284	448	**1,104,610**
Gas CHP biomass top-up	908,325	535,533	530	**1,443,859**

Table 34: Wallsend - System Annual Income Profile

System Annual Income profile		
Income Item	**Gas CHP & TU (£)**	**Gas-Biomass (£)**
Energy Sales (Private Wire only)	288,169	288,169
Energy Sales (Export Only)	178,918	178,918
RHI Income	-	19,147
Standing Charge	18,813	18,813
Business rates (Cost not income)	12,764	12,764

6.6.3 Network options - Financial assessment

A techno-economic analysis is presented for the Wallsend cluster for the following four technology options:

1. Gas CHP unit using private wire electrical distribution
2. Gas CHP unit with electricity exported to the national grid
3. Gas CHP unit plus biomass heat generation with private wire electrical distribution
4. Gas CHP unit plus biomass heat generation with electricity exported to the national grid

Table 35: Wallsend Cluster Summary Table

Wallsend Cluster				
		Appraisal (years)	IRR	NPV @ 6%
Gas CHP Private Wire	Without TS	25	6%	17,096
		40	8%	233,468
	With TS	25	8%	191,487
		40	9%	454,465
Gas CHP Export	Without TS	25	-	-1,276,429
		40	-	-1,307,285
	With TS	25	-	-1,390,309
		40	-	-1,429,656
Gas CHP + Bio Private Wire	Without TS	25	6%	-30,916
		40	7%	206,243
	With TS	25	7%	130,481
		40	8%	401,787
Gas CHP + Bio Export	Without TS	25	-	-1,324,441
		40	-	-1,334,510
	With TS	25	-	-1,451,316
		40	-	-1,482,335

Table 35 provides an overview of the financial performance of the four system options for the Wallsend network proposal at an assumed public sector borrowing rate of 6%. As the table highlights, on an export only basis neither the gas-only nor the gas with biomass systems return a positive NPV suggesting that they would not be viable given the capital investment required.

With the higher revenues secured via a private wire approach, both gas CHP & gas top-up and gas-biomass system options would be viable at the 6% target rate. The gas CHP & gas top-up approach returns a higher NPV over both the 25 and 40 year appraisal periods with a marginally greater IRR value.

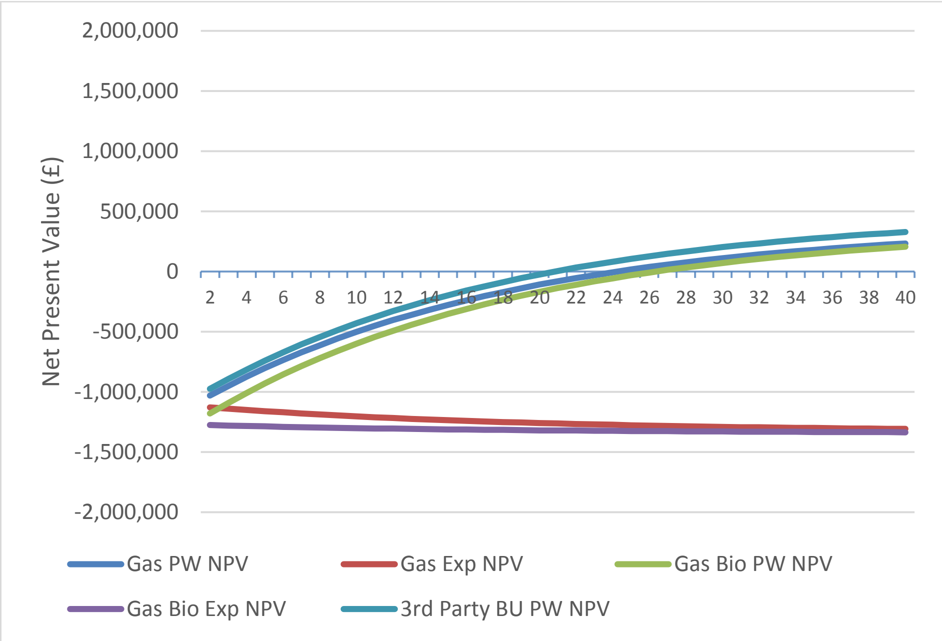

Figure 76: Wallsend Cluster – Modular CHP Outline Cost Evaluation (NPV discount rate @ 6%)

As Figure 76 demonstrates, by adopting a private wire approach the gas-biomass system is net positive from year 27, and the gas CHP & gas top-up system net positive from year 24 onwards, both systems having repaid the required capital outlay at this point. This suggests that the network would operate profitably from this point onwards.

On an export basis neither system can achieve a positive NPV over the longest appraisal period of a maximum of 40 years, which suggests that additional gap funding (to reduce capital expenditure) would be required in order to make the export only systems viable.

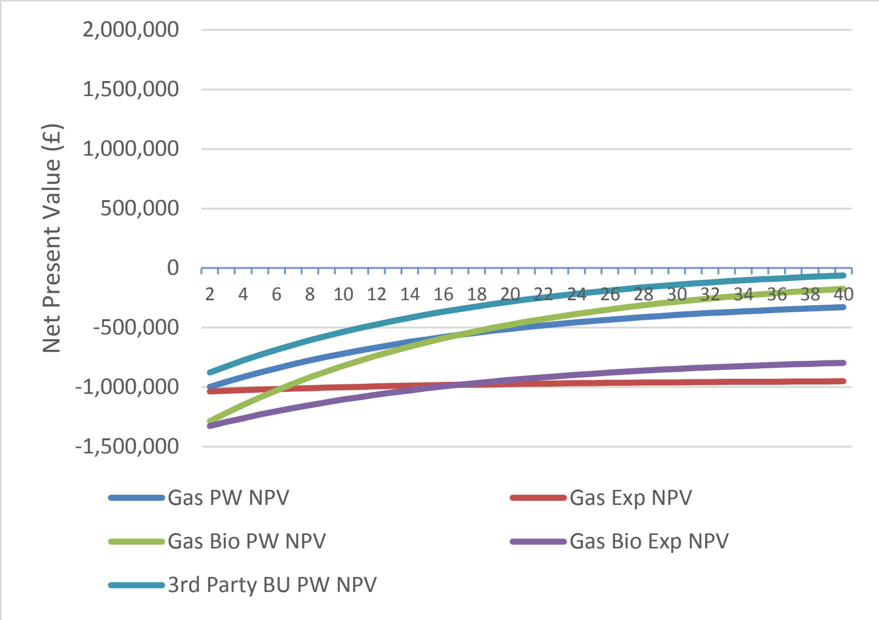

Figure 77: Wallsend Cluster – Base Load CHP Outline Cost Evaluation (NPV discount rate @ 6%)

In the case of the base load system on both a private wire and export only approach none of the technology configurations are able to return a positive NPV the target 6% rate over the longer 40 year appraisal period (figure 77). The third party top-up configuration comes closest due to the lower upfront capital requirement, although all systems in this scenario would require capital offset to meet the least stringent viability requirements.

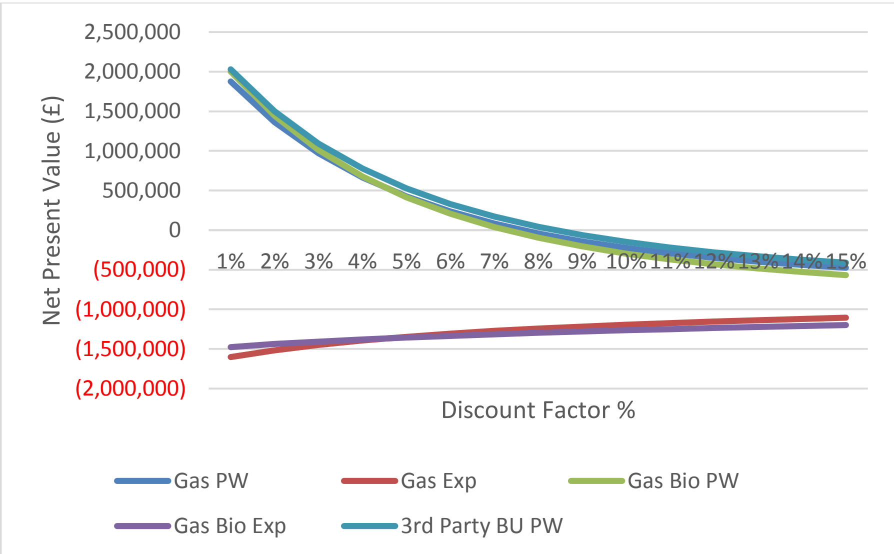

Figure 78: Wallsend Cluster – Modular CHP NPV DCF Sensitivity Analysis

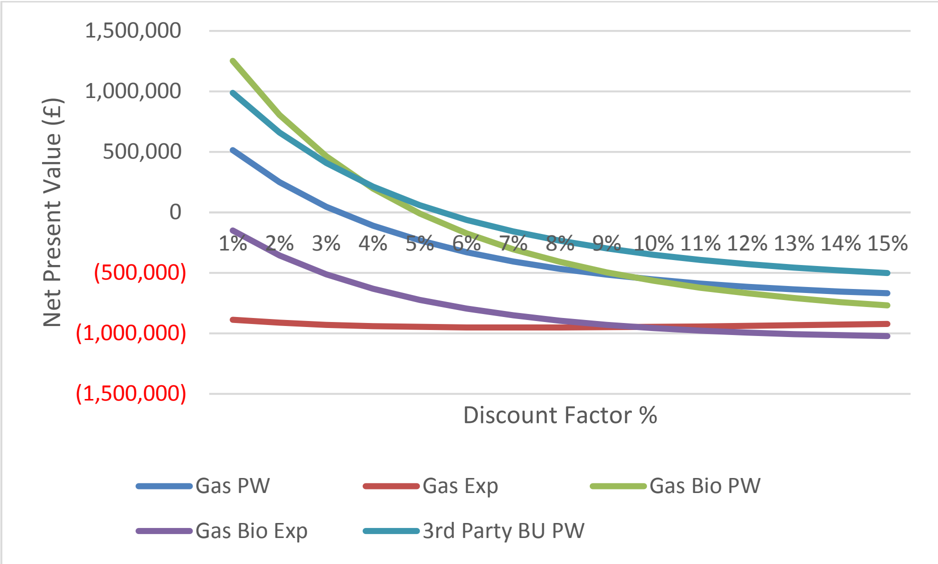

Figure 79: Wallsend Cluster – Base Load CHP NPV DCF Sensitivity Analysis

As Figure's 78 & 79 demonstrate, when a DCF analysis is undertaken for the Wallsend system options a mixed set of results are returned in terms of feasible borrowing rates for both the modular and base load proposals.

At a public sector borrowing rate of approximately 6% both modular private wire systems are feasible returning a positive NPV for both technology options over the 40 year period, although export systems are not viable at this rate. The same private wire systems fall short of the 10% private finance requirement as they are unable to maintain a positive NPV above approximately 7.5%.

No base load system configuration is able to maintain a positive NPV on a private wire or export only configuration for the 6% public borrowing target rate, or the 10% private finance rate (Figure 79).

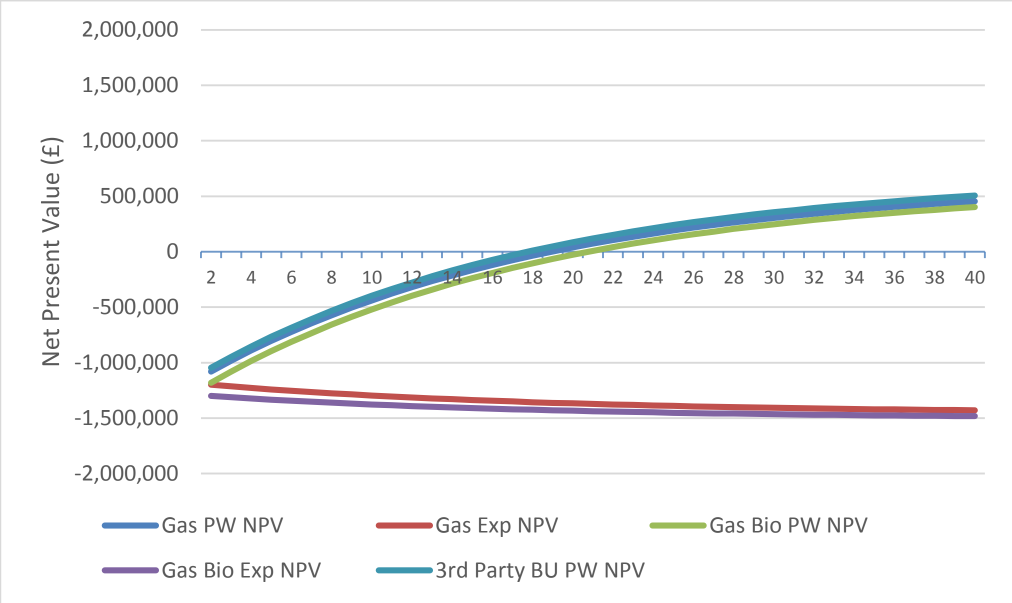

Figure 80: Wallsend Cluster Modular CHP with Thermal Store - Outline Cost Evaluation (NPV discount rate @ 6%)

The addition of thermal storage to the modular CHP proposal reduces the system payback time by 4 years (24 to 20 years) in the case of the gas CHP & gas top-up private wire systems (figure 80), and by just over 5 years in the case of the biomass top-up system (27 to just under 22 years). Neither modular export only scenario is able to generate a positive NPV. Figure 80 highlights that the modular private wire systems with thermal storage fall just short of generating a positive NPV at the 10% rate, although the 6% public rate is achieved. Neither rate can be achieved for the export only approaches however.

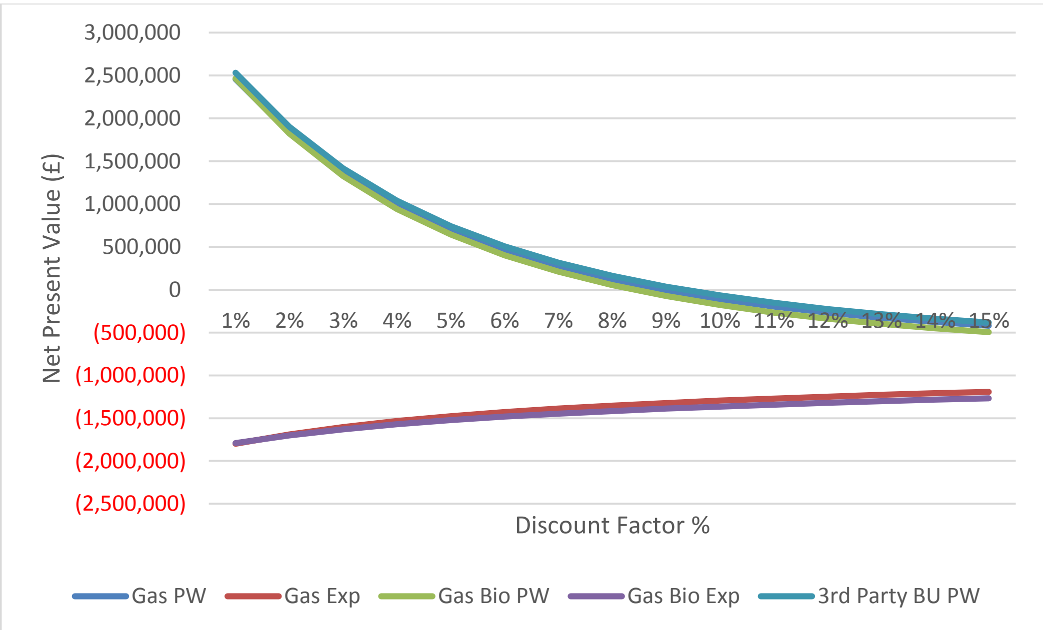

Figure 81: Wallsend Cluster Modular CHP with Thermal Store - NPV DCF Sensitivity Analysis

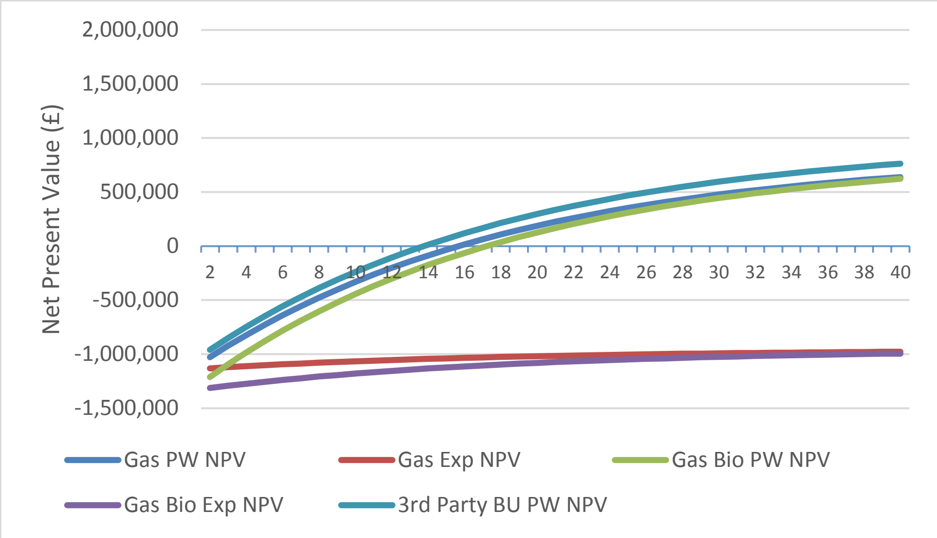

Figure 82: Wallsend Cluster Modular Base Load with Thermal Store - Outline Cost Evaluation (NPV discount rate @ 6%)

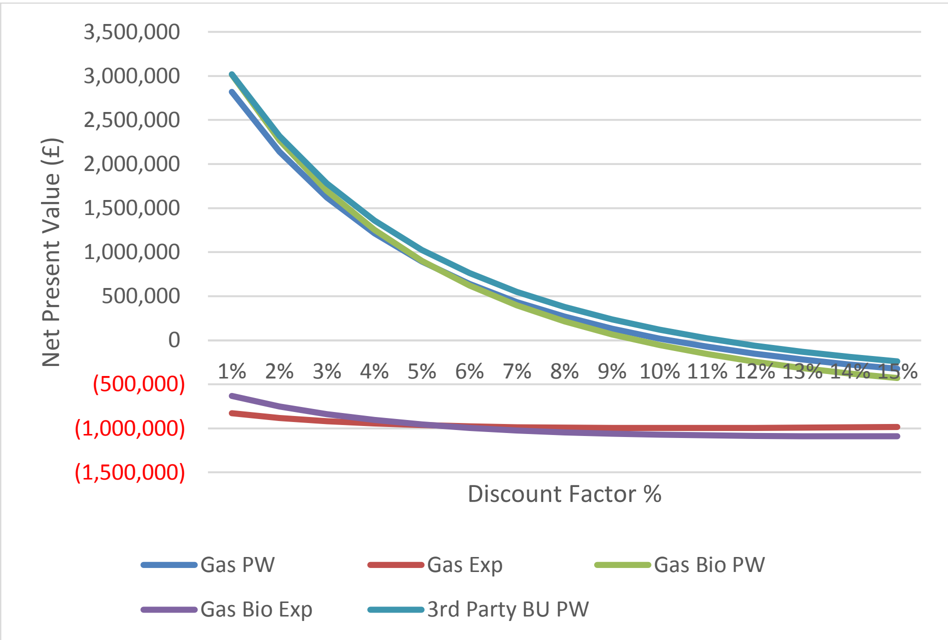

Figure 83: Wallsend Cluster Base Load CHP with Thermal Store - NPV DCF Sensitivity Analysis

Figures 82 and 83 highlight a similarly positive impact as a result of the addition of thermal storage to the base load CHP option, whilst export only approaches still fail to return a positive NPV, private wire approaches return a positive NPV from year 18 onwards at the latest. Private wire approaches just manage to sustain a positive NPV at the 10% target private rate, and the 6% public rate is comfortably achieved.

6.6.4 Proposal Evaluation – Summary:

There is reasonable diversity in terms of heat demand throughout the Wallsend cluster. Although the three schools within the cluster introduce considerable seasonality, this is offset to a certain extent by the more continuous year round demand of the leisure centre and the residential care homes, these buildings also assist in extending the daily operating profile of the system as a whole.

In terms of overall load risk with two of the six anchors being non-NTC buildings (both residential care homes) there is a medium level of load risk as a result, both of these care homes also provide higher heat and power demands than the two NTC primary schools so their long-term commitment to the network is critical to its success. In terms of system power generation the level of risk is lower with the combined annual consumption of the NTC buildings at approximately 92% of the generated power, although external commitment will have to be sought for the remaining 8%.

In terms of physical constraints, as identified on the proposal map (figure 71) land ownership constraints could present some issues. Potential energy centre locations are limited, and whilst a suitable site exists for the energy centre, this currently sits within an area of leased-out land and an extension to an existing concession within this site may have to be negotiated, whilst this is not likely to be overly onerous it could present an additional layer of complexity at the detailed feasibility stage.

In terms of likely network constraints, whilst the land ownership constraints are not prohibitive, as network mains can still be located in the highway, there could be limited opportunities to optimise routes. As the satellite overhead image in figure 73 demonstrates, soft-dig opportunities are limited in much of the proposal area. An element of existing utilities congestion should be expected given the age of the built environment in the town centre. Further to the utilities congestion, congestion of a different kind may be encountered where distribution mains has to cross Church grounds to access the two residential care homes.

In terms of financial viability, as with many of the other proposals the grid-export approach is not viable for any of the configurations generating a negative NPV higher than the initial capital outlay highlighting that none of these systems are able to repay any of the upfront investment, essentially running at a loss once operating overheads are factored in (table 35).

Under a private wire approach both technology configurations with or without thermal storage are viable at public financing rates (table 31). The gas CHP & gas top-up modular CHP system generates a slightly higher IRR than the biomass top-up alternative at 8% and 7% respectively, with the addition of thermal storage IRR's of 9% for the gas CHP & gas top-up, and 8% for the biomass top-up system are achieved. Proposals fall just short of private financing requirements in all scenarios, although requirements could be met with additional capital support of between 10-15% for the modular systems with thermal storage depending on technology configuration.

In terms of overall viability, whilst private wire configurations are feasible at lower public borrowing rates, both options require further capital support to meet private borrowing requirements. Further to this there are risks around the dependence on external buy in, along with physical constraints resulting from the built environment within the proposal area. With all these factors considered, although the Wallsend proposal is financially viable in some scenarios, and technically feasible in most, of the various proposals available this system would not be a priority for further exploration at the feasibility stage.

6.7 Whitley Bay System proposal

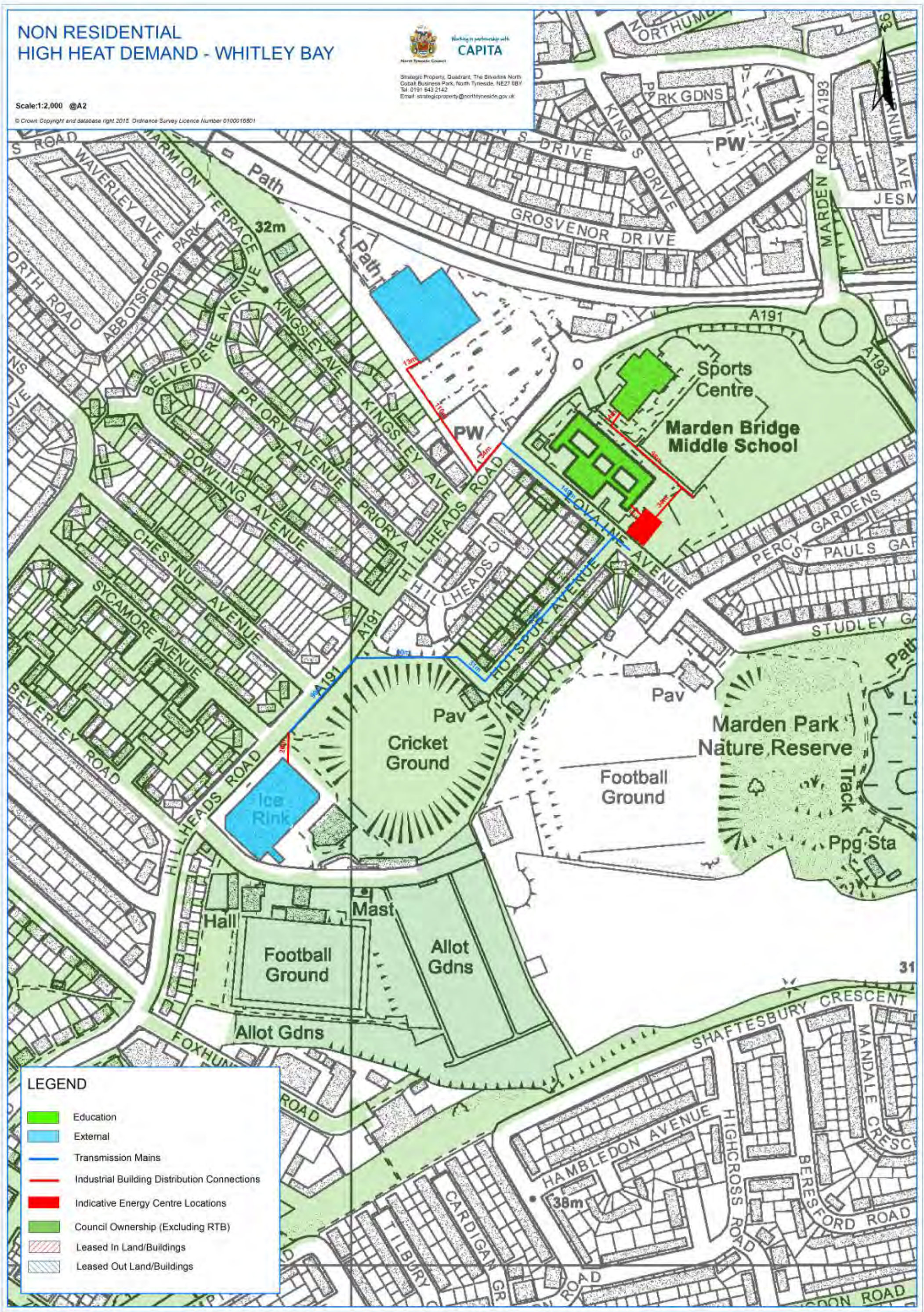

Figure 84: Whitley Bay System proposal map

6.7.1 Whitley Bay System – Anchor Buildings and Energy Centre Location

Table 36: Whitley Bay - Anchor Building Properties

Building	Size m2	Annual Heat demand (MWh)	Annual Power demand (MWh)	Annual Cooling demand (MWh)	Data Source	Comments
Marden Bridge Middle School	4,790	445	157	n/a	Actual consumption data from NTC EM System	Large Victorian school with lower summer base-load & no heating load from June to September
Marden bridge leisure Centre	1,509	230	117	15	Actual consumption data from NTC EM System	Modern dry leisure centre with high DHW demand and fairly constant seasonal load profile.
Morrisons Supermarket	4,226	444	2,513	43	Modelled on CIBSE TM46 benchmark using GIS measurement	Medium sized food store – assumed no heating load in July & August
Whitley Bay Ice rink	3,675	323	491	n/a	Modelled on CIBSE TM46 benchmark using GIS measurement	Large Indoor Ice rink with limited space heating and no heating load in July & August

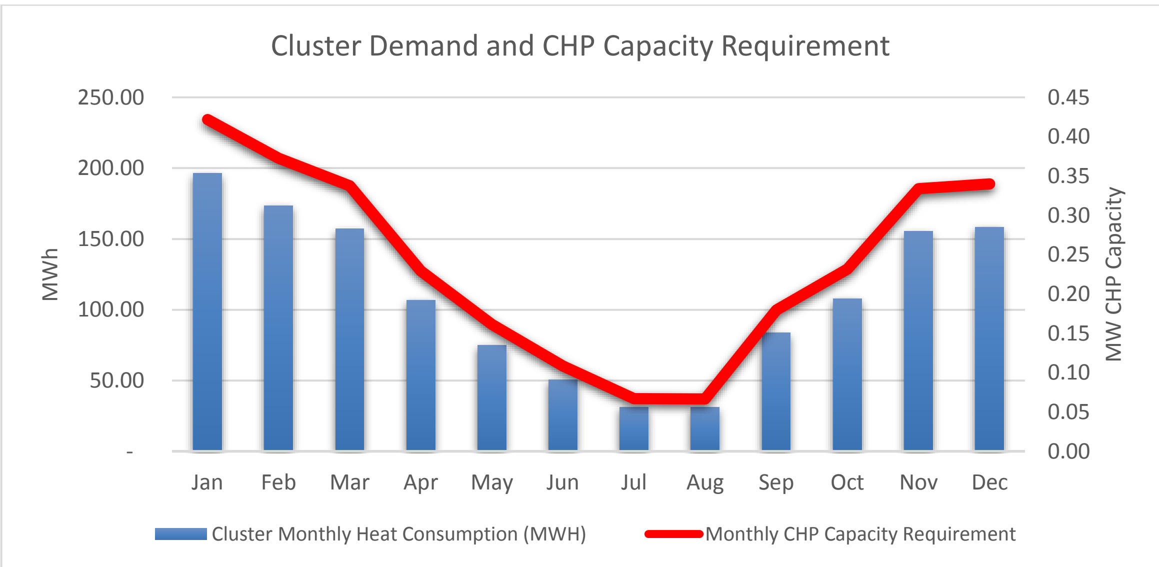

Figure 85: Whitley Bay - Monthly Heat Demand & CHP Capacity Requirement

The Whitley Bay cluster includes some diversity in terms of anchor buildings (table 36). Although there is only one school within the cluster there is still noticeable seasonality in the heat demand profile, as identified in the above graphic, with a noticeable drop in demand in June and August. Despite the seasonality, there is significant heat demand throughout the winter heating months, and the seasonality of the school is offset to an extent by the external buildings which have a smoother demand profile (figure 85). The success of this network proposal will be heavily dependent on the buy-in of the landlords for the supermarket and the ice rink as their long-term commitment would be critical to delivering a viable network.

Two of the four buildings within the cluster are NTC operational buildings with actual consumption data available, with the remaining two external buildings reliant on benchmark modelled data, the combined load of these modelled buildings is in excess of half of the overall load for the cluster and as such further attention would be required at the feasibility stage to test the benchmark outputs.

Figure 86: Whitley Bay - Aerial Satellite View

As the proposal map (figure 84) identifies there is a good level of NTC landownership within the proposal area and the majority of the land affected is within NTC ownership, the only non-NTC owned land is that which is owned by the external sites and it is assumed that, as long as they are willing to join the network, there would be no objection to granting access over land to connect these buildings. In addition to the land ownership, the above image demonstrates a number of soft-dig opportunities offering reasonable flexibility in network routing and infrastructure costs.

6.2.2 Energy Centre Location – Justification & Rationalisation

The satellite image below (Figure 87) identifies an NTC site adjacent to the school (bottom right corner of image) on Lovaine Avenue which is currently surplus to requirements and being marketed for disposal. This site is approximately 900m2, is accessible from the highway, and could comfortably accommodate the maximum energy centre requirement of 90m2 along with any additional requirement for biomass or thermal storage.

Further assessment of proposed Energy Centre sites; including; Air Quality Assessment, Noise Disturbance Assessment, Visual Impact Assessment, and Planning Risk, will be undertaken at subsequent stages.

Figure 87: Whitley Bay - Aerial Satellite View (2)

The NTC Asset Management and NTC Energy Management function have confirmed that both the Middle School, and the Sports Centre, are heated by traditional medium temperature wet heating systems operating at approximately 80°C flow with 70°C return. Domestic hot water is supplied by with calorifiers operating at 60°C flow and 50°C return. The details of the heating systems for the external buildings are not known. It is assumed that the supermarket is served by a traditional central boiler setup operating to 80°C flow with 70°C return, with domestic hot water calorifiers operating on similar parameters to the NTC operational buildings. It is assumed that the Ice rink operates a traditional system setup for space heating and DHW, although it is likely that the cooling system for the rink itself will involve something more sophisticated, the detail of which will require further consideration at the feasibility stage.

6.7.2 System configuration and Technology Options

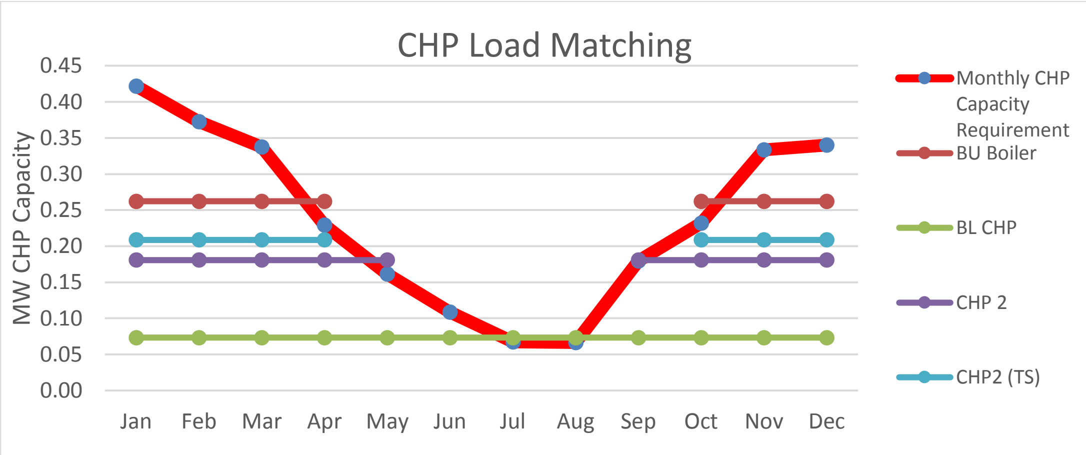

Figure 88: Whitley Bay - Monthly CHP Capacity Requirement & CHP Load Matching

With a summer base-load demand of 31 MWh in August (figure 88), sizing a gas CHP unit according to the base-load demand would dictate a maximum CHP size of 70kWt/58kWe, with a top-up boiler capacity requirement of 570kWt for gas fired boilers, or 620kWt for Biomass boilers (figure 88). On a base-load CHP sizing basis only 28% of the annual heat demand would be served by the CHP unit with the remainder being provided by the back-up boilers.

Following a modular CHP approach were adopted the smaller base-load CHP unit could be supported a larger 180kWt/140kWe CHP unit to provide a combined capacity of 250kWt/200kWe which would provide approximately 83% of the annual heat demand and reducing back-up boiler capacity requirement to 260kWt for gas fired boilers, or 290kWt for Biomass boilers. Further to this the modular CHP approach would generate an additional 683 MWh of power for sale via private wire, or export.

For both the gas-only, and gas-biomass system options electricity sale via a private-wire only, and export only approaches have been modelled to assess establish the value of the different approaches.

Network infrastructure costs to connect the Whitley Bay anchor buildings total £762,722. Of this 532m of transmission mains are required at a cost of £523,448 with a further 340m of distribution mains at a cost of £204,000, and a total of £35,234 for building connections.

Total capital costs for the gas CHP & gas top-up network including network infrastructure, plant and energy centre costs come to £944,114. Whereas the total cost for the biomass top-up system comes is higher at £1,061,530 due to the higher cost of biomass heating plant and ancillary equipment (table 37).

With a combined volume of 37.6m3 the network transmission mains provide an inherent storage capacity of approximately 1.7MWh, or the equivalent system run time of 3.8 hours. An additional capacity of 36.5m3 has been specified for the modular CHP thermal storage model providing an additional 1.7MWh of storage at a cost of £30,822, the same vessel has been specified for the single CHP thermal storage model as this provides the closest fit to the cluster demand profile.

Annual power generation for the larger modular CHP configuration, once adjusted for network parasitic electrical load, provides approximately 997MWh. The combined annual electrical consumption of the NTC operational buildings within the cluster is approximately 275MWh or around 28% of the total generated power. The combined annual electrical consumption of the non-NTC buildings within the cluster is approximately 3,004MWh, approximately 301% of the generated power. On this basis the assumption that all of the CHP generated power can be sold via private wire can be upheld, although lower system revenues based on electricity sale exclusively at export prices will be assessed in the interests of stress testing the proposals.

Table 37: Whitley Bay - System Cost Summary

System	Network Infrastructure costs (£)	Energy Centre & Plant costs (£)	Potential CO2 abatement (tonnes p/a)	Total cost (£)
Gas CHP & TU	762,722	181,391	295	**944,114**
Gas CHP biomass top-up	762,722	298,807	350	**1,061,530**

Table 38: Whitley Bay - System Annual Income Profile

System Annual Income profile		
Income Item	**Gas CHP & TU (£)**	**Gas-Biomass (£)**
Energy Sales (Private Wire only)	191,060	191,060
Energy Sales (Export Only)	118,610	118,610
RHI Income		12,657
Standing Charge	10,263	10,263
Business rates (Cost not income)	8,456	8,456

6.7.3 Network options - Financial assessment

A techno-economic analysis is presented for the Whitley bay cluster for the following four technology options:

1. Gas CHP unit using private wire electrical distribution
2. Gas CHP unit with electricity exported to the national grid
3. Gas CHP unit plus biomass heat generation with private wire electrical distribution
4. Gas CHP unit plus biomass heat generation with electricity exported to the national grid

Table 39: Whitley Bay Cluster Summary Table

Whitley Bay Cluster				
		Appraisal (years)	IRR	NPV @ 6%
Gas CHP Private Wire	Without TS	25	4%	-158,629
		40	6%	-18,715
	With TS	25	5%	-110,913
		40	6%	45,248
Gas CHP Export	Without TS	25	-	-1,016,431
		40	-	-1,014,467
	With TS	25	-	-1,070,201
		40	-	-1,097,386
Gas CHP + Bio Private Wire	Without TS	25	4%	-197,499
		40	6%	-43,843
	With TS	25	4%	-152,096
		40	6%	13,853
Gas CHP + Bio Export	Without TS	25	-	-1,055,301
		40	-	-1,065,595
	With TS	25	-	-1,111,384
		40	-	-1,128,781

Table 39 provides an overview of the financial performance of the four modular system options for the Whitley Bay network proposal at an assumed public sector borrowing rate of 6%. As the table highlights, few systems return a positive NPV suggesting that they would not be viable given the capital investment required. The only systems able to return a positive NPV over the longer 40 year appraisal period are the private wire thermal storage configurations.

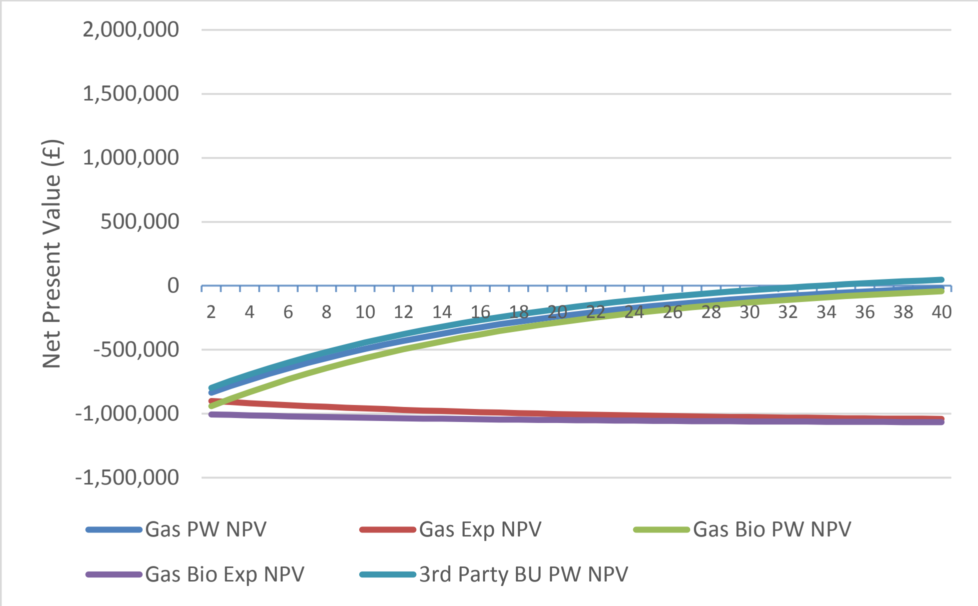

Figure 89: Whitley Bay – Modular CHP Outline Cost Evaluation (NPV discount rate @ 6%)

As Figure 89 demonstrates, none of the modular CHP systems achieve a net positive position over either the 25 or 40 year appraisal period, indicating that no system configuration is capable of repaying the capital outlay required. Significant additional gap funding (to reduce capital expenditure) or cost reduction would be required in order to make the systems viable. The same is true for the base load systems as highlighted by Figure 90.

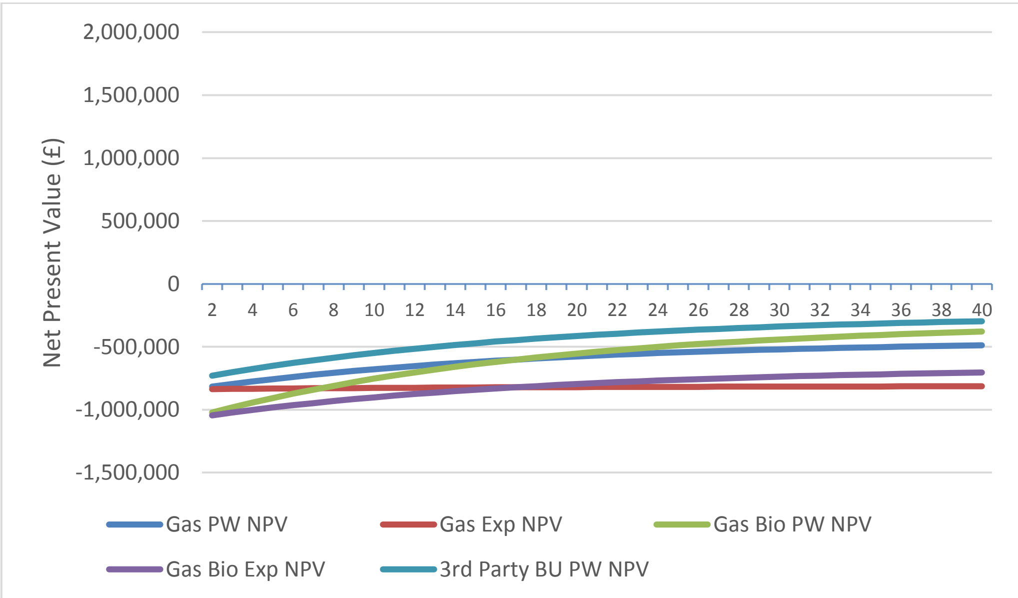

Figure 90: Whitley Bay Cluster – Base Load CHP Outline Cost Evaluation (NPV discount rate @ 6%)

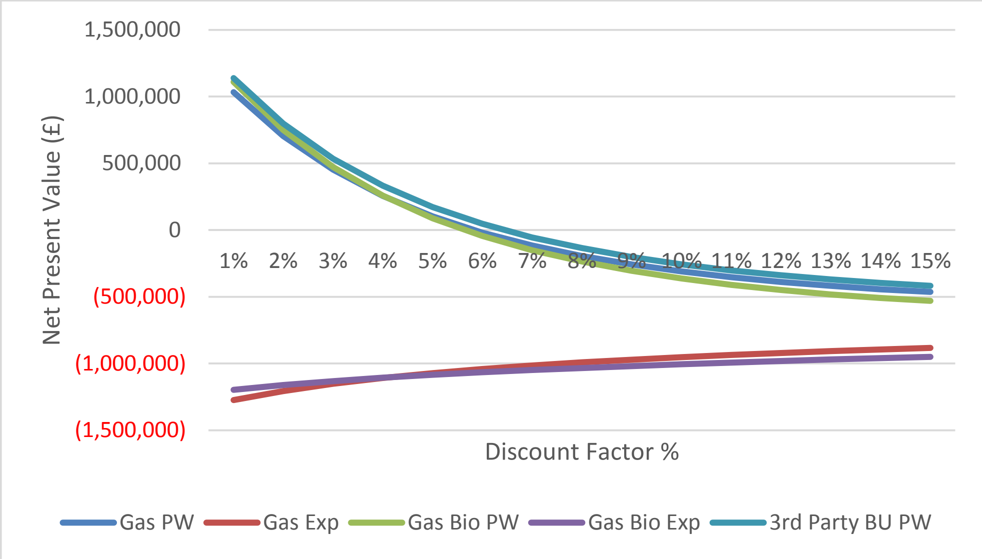

Figure 91: Whitley Bay Cluster – Modular NPV DCF Sensitivity Analysis

As figure 91 demonstrates, when a DCF analysis is undertaken for the modular system options, the results returned are not favourable in terms of feasible borrowing rates for the proposals.

At a public sector borrowing rate of approximately 6% neither private wire system is feasible, with a negative NPV of -£18,715 returned for the gas-only system, and a negative NPV of -£43,843 returned for the gas-biomass option over the 40 year period.

At a higher private sector borrowing rate of 10% none of the system options returns a positive NPV suggesting that securing private sector interest in these proposals would be a challenge. The gas CHP & gas top-up private wire system is the closest with a negative NPV of -£-309,871, and it is very unlikely that further value engineering could achieve a positive figure. In reality, all of these system proposals would require reinforcement with significant further capital before private sector interest could be secured.

The base-load CHP systems present similar feasibility challenges as identified in the various figures provided on page 30 of the Master Planning Report Supplement document. None of the base load systems modelled is able to generate a positive NPV at either the 6% public borrowing or 10% private finance target rates.

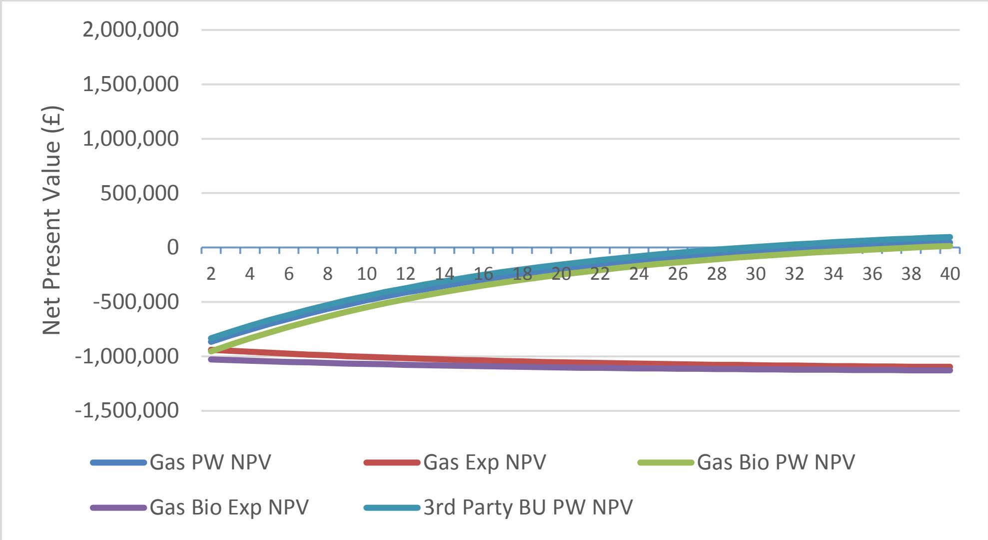

Figure 92: Whitley Bay Cluster with Thermal Store – Modular CHP Outline Cost Evaluation (NPV discount rate @ 6%)

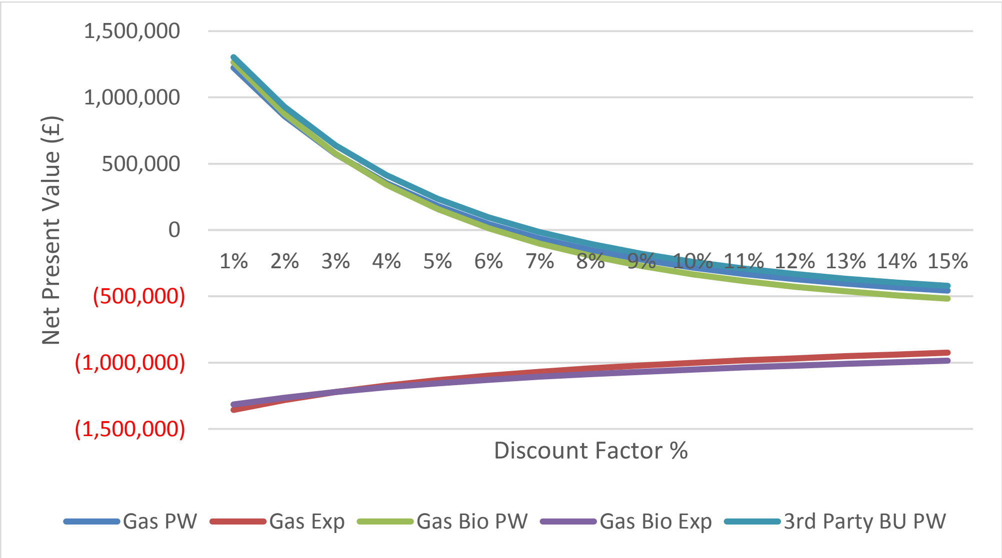

Figure 93: Whitley Bay Cluster with Thermal Store - Modular CHP NPV DCF Sensitivity Analysis

In the case of the private wire modular systems the addition of thermal storage provides a moderate improvement in terms of financial performance with the gas CHP & gas top-up and biomass top up systems just managing to generate a positive NPV at the 6% public target rate over the longer 40 year appraisal period (figures 92 & 93). The private finance target rate is not achievable. Export configurations are unable to meet either target rate with the addition of thermal storage

In the case of the base-load proposals a similar moderate improvement in financial performance is highlighted on page 30 of the Master Planning Report Supplement document with both private wire systems able to achieve positive NPVs of £42,266 for the gas CHP & gas top-up system, and £54,770 for the biomass top-up system at the lower 6% target rate. Neither system is able to meet the 10% private finance target rate. None of the export only configurations are able to meet either the public or private target rate with the addition of thermal storage.

In summary the financial analysis suggests that the Whitley Bay network proposal is not viable at public financing rates under either private wire scenario demonstrating a negative NPV across both technology options. Further to this, neither option is feasible under a grid-export scenario. Private financing is unlikely to be achievable without further considerable capital support.

6.7.4 Proposal Evaluation – Summary:

Of all the potential networks assessed the Whitley Bay proposal sat at the smaller end of the scale. Whilst this presents some benefits in terms of the lower levels of upfront capital required, this is offset by the weaker financial performance outlined in the analysis in previous sections

In terms of overall load risk with two of the fours anchors being non-NTC buildings there is a high level of load risk as a result, both of these buildings also provide higher heat and power demands than the two NTC sites so their long-term commitment to the network is critical to its success. In terms of system power generation the level of risk is similarly high with the combined annual consumption of the NTC buildings at only approximately 28% of the generated power, with the remaining 72% depending on external commitment.

In terms of physical constraints, as identified on the proposal map (figure 84) land ownership constraints present less of an issue. Potential energy centre locations are limited, but a suitable vacant site exists for the energy centre which has been declared surplus to requirements and has been marketed without success. In terms of likely network constraints, there are some land ownership constraints although the use of highways can be limited in many instances. There are also a number of opportunities to optimise routes (figure 86).

In terms of financial viability, grid-export approaches generate a negative NPV higher than the initial capital outlay as all configurations are unable to repay any of the upfront investment, essentially running at a loss once operating overheads are factored in (table 39).

Under a private wire approach only the modular systems with thermal storage are able to recover the capital outlay achieving a 6% IRR at public financing rates (table 39). On this basis both systems are only able to generate a positive NPV in the final (40^{th}) year of the longer evaluation period. No other system configurations are able to generate a positive NPV and recover the capital outlay at the lower public rate. Higher private financing rates are unachievable for any system configuration. Whilst capital gap funding of up to 10% would do much to improve the performance of non-storage modular systems at public rates, the level of gap funding required to achieve private financing rates is between 30-35% depending on configuration.

In terms of overall viability, all configurations within the proposal fail to demonstrate sufficiently robust financial performance without significant capital reinforcement. Further to this there are significant risks around the dependence on external buy in. With all these factors considered in the round, the Whitley Bay proposal does not warrant further exploration at the feasibility stage.

7.0 Conclusion and Recommendations

7.1 Summary Evaluation of System Proposals

Table 40 provides a summary of the key outputs from the financial analysis of each of the system proposals.

Based on the summary information a number of conclusions are immediately apparent. Under an export only approach whereby the power generated is sold directly to the national grid, no proposal would be viable over the shorter 25 year, or longer 40 year period, even at the relatively lower borrowing rate of 6%. This signifies both that, electricity sales are critical to the success of the network (no proposal can be sustained by the sale of heat alone), and that the direct sale of electricity via private wire is essential due to the higher revenues generated as a result of the higher unit price that can be achieved.

The higher costs associated with Biomass heating plant affect the financial performance of all proposals despite the additional income provided by the Renewable Heat incentive (RHi) tariff revenues which would be generated by these systems. This may be a result of the modular CHP sizing approach which seeks to maximise the amount of heat delivered via the CHP units, in turn minimising the operation of the top-up biomass boilers. However, this approach is supported by the findings above which indicate that power generation must be prioritised to ensure optimal revenues are secured from system energy sales. There is also an element of future-proofing here in that reliance on non-energy incomes (from external tariff mechanisms) could jeopardise a systems future viability if there were a subsequent change in policy around tariff support for low-carbon technologies. This has certainly been the experience for renewable power generation technologies under the Feed-In Tariff (FiT) mechanism over recent years.

The system proposals for the second phase of the A19 South system, the North Shields system, and the Whitely Bay system are simply not viable as demonstrated by the key evaluation outputs. None of these systems are able to return a positive net present value and subsequent positive rate of return under any configuration or approach. Under each of these proposals the capital costs of establishing these systems cannot be recovered by energy sales across even the longer 40 year appraisal period. The level of capital offset required to make these projects viable propositions in investment terms is unlikely to be available in the current public funding environment.

Of the six system proposals assessed, three of the system proposals meet the outline requirements of the financial assessment and as such might warrant further analysis at the feasibility stage, these systems are addressed in the subsequent recommendations section.

Table 40: Financial Evaluation Summary Table (All schemes)

System	Technology	Cost (£)	25 Year NPV (£)	IRR %	40 Year NPV (£)	IRR %	Capital Offset required (£)	Load Risk	Annual CO2 abatement (tonnes)
A19 North	Gas CHP & TU PW	2,408,391	1,156,033	1	1,811,237	12	-	66% High Load Risk 4 of 6 Buildings non-NTC	1,320
	Gas CHP & TU Exp		-2,779,518	-	-2,876,506	-	2,876,506		
	Gas-Bio PW	2,803,494	1,221,781	11	1,960,791	12	-		1,654
	Gas-Bio exp		-2,713,770	-	-2,726,951	-	2,726,951		
A19 South (Phase 1 only)	Gas CHP & TU PW	730,556	16,822	6%	151,763	8%	-	0% Zero Load Risk 0 of 5 Buildings non-NTC	305
	Gas CHP & TU Exp		-865,679	-	-899,409	-	899,409		
	Gas-Bio PW	994,098	-10,366	6%	166,898	7%	-		474
	Gas-Bio exp		-892,867	-	-884,271	-	892,867		
Killingworth	Gas CHP & TU PW	2,022,047	452,933	8%	904,094	10%	-	17% Low Load Risk 1 of 6 Buildings non-NTC	948
	Gas CHP & TU Exp		-2,297,250	-	-2,371,725	-	2,371,725		
	Gas-Bio PW	2,338,495	344,416	8%	831,894	9%	-		1,092
	Gas-Bio Exp		-2,405,768	-	-2,443,925	-	2,443,925		
North Shields	Gas CHP & TU PW	1,180,450	-273,814	3%	-113,301	5%	113,301	57% High Load Risk 4 of 7 Buildings non-NTC	350
	Gas CHP & TU Exp		-1,278,739	-	-1,310,295	-	1,310,295		
	Gas-Bio PW	1,297,243	-306,959	3%	-131,723	5%	131,723		409
	Gas-Bio Exp		-1,311,884	-	-1,328,717	-	1,328,717		
Wallsend	Gas CHP & TU PW	1,104,610	17,096	6%	233,468	8%	-	33% Medium-low Load Risk 2 of 6 Buildings non-NTC	448
	Gas CHP & TU Exp		-1,276,429	-	-1,307,309	-	1,307,309		
	Gas-Bio PW	1,443,859	-30,916	6%	206,243	7%	-		530
	Gas-Bio Exp		-1,324,441	-	-1,334,510	-	1,334,510		
Whitley Bay	Gas CHP & TU PW	944,114	-158,629	4%	-18,715	6%	18,715	50% High Load Risk 2 of 4 Buildings non-NTC	295
	Gas CHP & TU Exp		-1,016,431	-	-1,014,467	-	1,014,467		
	Gas-Bio PW	1,061,530	-197,499	4%	-43,843	6%	43,843		350
	Gas-Bio Exp		-1,055,301	-	-1,065,595	-	1,065,595		

7.2 Recommendations for Feasibility analysis

Table 41: Recommended Systems for Feasibility Analysis

System	Technology	Cost (£)	25 Year NPV (£)	IRR %	40 Year NPV (£)	IRR %	Capital Offset required (£)	Load Risk	Annual CO2 abatement (tonnes)
A19 North	Gas CHP & TU PW	2,408,391	1,156,003	11	1,811,237	12	-	66% High Load Risk 4 of 6 Buildings non-NTC	1,320
	Gas-Bio PW	2,803,494	1,221,781	11	1,960,791	12	-		1,654
A19 South (Phase 1)	Gas CHP & TU PW	730,556	16,822	6	151,763	8	-	0% No Load Risk 0 of 5 Buildings non-NTC	305
	Gas-Bio PW	994,098	-10,366	6	166,898	7	-		474
Killingworth	Gas CHP & TU PW	2,022,047	452,933	8	904,094	10	-	17% Low Load Risk 1 of 6 Buildings non-NTC	948
	Gas-Bio PW	2,338,495	344,416	8	831,894	9	-		1,092

The strongest financial performance of all the systems assessed via pre-feasibility modelling is provided by the A19 North proposal. The network achieves a positive NPV for both the gas CHP only and gas CHP with Biomass top-up configurations under a private wire approach over both the shorter and longer appraisal period. Both system configurations also generate rates of return in excess of 10% at a 6% discount rate. The A19 North system also offers the highest carbon abatement potential of the three shortlisted recommendations under either technology option. Whilst there are numerous positive aspects to the proposal, attention must be paid to the level of load risk with this system. Four of the six anchor buildings are non-NTC buildings and as such the reliance on commitment from external parties should be assessed further at the feasibility stage. Potential land and building ownership constraints should also be further assessed at the feasibility stage to ensure that assumptions about the potential energy centre location are valid. Whilst the strong financial performance of this proposal is clear, at this stage there remain a number of considerable risks which must be considered prior to short-listing this proposal for further detailed analysis. Whilst the other two systems may not appear as impressive in terms of financial or environmental achievements, in terms of overall deliverability they may present more suitable opportunities.

Phase 1 of the A19 South proposal returns a positive NPV for both technology options across the longer 40 year appraisal period at an IRR of between 7% and 8% depending on technology. The gas CHP & gas top-up system achieves a positive position across the shorter 25 year period, and whilst the biomass system falls slightly short, both options still achieve an IRR of 6%. Given that a positive NPV is achieved over the 40 year period this is less of a concern. It is also entirely possible that this shortfall could be overcome by value engineering under further detailed analysis at the next stage to improve financial performance over the shorter term. Whilst the carbon abatement potential for this proposal is considerably lower than the other two schemes, the strength of this proposal lies in the lack of an external load risk in terms of heat and private wire power sale, along with relatively little in the way of physical or technical constraints which could threaten the systems success.

The Killingworth system proposal also offers a positive NPV under private wire approach for both configurations over the shorter and longer appraisal period. IRR rates are slightly lower than the A19 North system at between 8% and 10%. Whilst the carbon abatement potential under both technology options is the lower than the A19 North system, the load risk is significantly lower with the proposal reliant on just one external building. Securing the interest of a single stakeholder at the next stage will be considerably more achievable than having to liaise with multiple individual building owners as with many of the other proposals.

In summary each of these modelled systems represents a viable proposal at pre-feasibility stage which is worthy of further analysis at a finer grain. This should be the next step taken prior to any final decisions being made on the ultimate viability of the shortlisted modelled networks. A subsequent stage of high-level feasibility analysis would allow the further testing of each proposal using more sophisticated financial and cost analysis techniques.

It is our recommendation that the positive outcomes of this Master-Planning exercise in terms of the viable proposals identified are taken forward for further feasibility analysis to build upon the findings of this study. Each of these viable proposals will contribute to the achievement of the NTC Low Carbon Plan Strategic Objectives no's. 2&3 (page 12); Energy Efficiency, Energy Generation & Income. Future extension of proposals to serve residential properties could also contribute to objective 4: Fuel Poverty.

We understand that budgetary constraints at the subsequent stage of this work restrict the Council to a detailed analysis of only two network proposals. On this basis we would recommend that the identified risks associated with the A19 North proposals are given serious consideration, with the recommendation that the Killingworth and A19 South (Phase 1) proposals are given preference in light of deliverability. Although we appreciate that the final decision can only be taken by the Council in consideration of each of the proposals on their own merits.

7.3 Port of Tyne: Howdon Green Energy Park Proposal

A significant development subsequent to the re-submission of the Energy Master plan report has been the announcement by the Port of Tyne of their intention to bring forward an energy from waste development on their Howdon site (figure 94). The proposal involves construction of a gasification facility which will process household waste into a combustible product to generate power.

Figure 94: Port of Tyne Howdon site

There is little detail available at this stage, as formal planning consultation has not yet commenced and no formal guidance has been sought from the North Tyneside Planning Authority. Although an indication of a 25MW capacity facility has been publicised. Whilst it is not possible to undertake a meaningful assessment of the opportunity given the lack of detail available, the potential waste heat created via power generation could provide a significant resource to heat network proposals throughout the borough. A full assessment of this opportunity during later feasibility phases will be very much dependant on the timing of this development and the availability of technical detail from the developer, as well as proactive engagement with the Port of Tyne. However, all efforts should be made to ensure that the development of any heat network proposals are aligned to this emerging development, if possible, to avoid potential opportunities being overlooked.

Figure 95: Howdon site – Artists Impression

Appendix 1: Model Assumptions:

Table 42: Model Assumptions

Monthly Heat Demand	
Building Size	Building sizes are taken from DEC TUFA measurement for public buildings and EPC measurements for private buildings where available. Where not available, sizes derived from GIS OS Map measurements adjusted for net internal area (NIA) & number of building storeys. The building sizes are only used to model annual standing charges for buildings for which actual consumption data is available, and used to model predicted annual consumption for buildings where actual consumption data was not available.
Gas Consumption	The annual gas consumption for each building identified is taken from actual billed consumption where available (NTC operational buildings) or from DEC certificates or EPC's where available for non-NTC buildings, Where a DEC or EPC is not available consumption has been derived using CIBSE TM46 or CIBSE Guide-F benchmarks in conjunction with GIS OS Map measurements.
Efficiency Correction	An efficiency correction is applied to each buildings annual gas consumption figure to correct for boiler efficiency (assumed 80%) to derive actual heat consumption from total gas consumption
Heat Corrected MWh	The buildings heating consumption is apportioned at 65% of total efficiency corrected consumption
DHW Corrected MWh	The buildings domestic hot water consumption is apportioned at 35% of total efficiency corrected consumption. The only exceptions to this are leisure buildings where wet leisure buildings are assumed to have a much higher DHW apportionment of 70% due to the heating of pool water, and dry leisure buildings which are assumed to have a DHW apportionment of 40% due to higher WC/Shower & changing facility use.
Monthly Profiled MWh	The monthly profiled MWh consumption of each building is derived based on a number of assumptions specific to that buildings type (use): Schools – the consumption profile is based on current building management system programming schedules for NTC schools. The winter heating schedule is in operation from September to March (6 months full day heating programme, approximated at 70% of annual heating consumption). The spring heating schedule is in operation from March to May (3 months Half day heating programme, approximated at 30% of annual heating consumption). There is no heating programmed from June to August based on seasonal average temperatures and school closure over the summer holiday period. Domestic hot water is programmed for operation across 11 months of the year, excluding August due to summer holiday closure. Office accommodation – NTC office accommodation sites are currently programmed for DHW operation for 12 months of the year. The winter heating schedule is in operation from September to March (6 months full day heating programme, approximated at 70% of annual heating consumption). The spring heating schedule is in operation from March to July (4 months Half day heating programme, approximated at 30% of annual heating consumption). There is no heating programmed from July to August based on seasonal average temperatures.

	Wet leisure facilities are currently programmed for DHW operation for 12 months of the year. The winter heating schedule is in operation from September to March (6 months full day heating programme, approximated at 70% of annual heating consumption). The spring heating schedule is in operation from March to September (6 months Half day heating programme, approximated at 30% of annual heating consumption). Dry leisure facilities are currently programmed for DHW operation for 12 months of the year. The winter heating schedule is in operation from September to March (6 months full day heating programme, approximated at 70% of annual heating consumption). The spring heating schedule is in operation from March to July (4 months Half day heating programme, approximated at 30% of annual heating consumption). There is no heating programmed from July to August based on seasonal average temperatures. It is assumed for modelling purposes that private/external buildings will follow the same seasonal profile as the equivalent NTC building, external retail is assumed to correspond to the consumption profile for NTC multi-use buildings based on similar operational/occupational hours, hotels are assumed to correspond to the consumption profile for NTC dry leisure buildings on the same basis.
Monthly Cluster Consumption	This is the sum of the apportioned heat and DHW consumption for each of the sites within the cluster. This identifies the consumption profile of the cluster as a whole and identifies the combined base-load, max-load, and average load to assist with CHP sizing
CHP & Plant Sizing (based on CIBSE AM12)	
Average Heat output	This figure is driven by the Base-load or Modular CHP Capacity, or the average load CHP Capacity figure where a thermal store is used
Average Electrical output	This figure is derived from the average Heat output factor
CHP run hours per year	This figure is derived from an assumed 17hr per day, 365 days per year CHP operational profile (adjusted for a 90% availability factor) Thermal storage models are adjusted for an additional 3 hrs run time (20hrs per day) to derive appropriate thermal storage vessel sizes and associated costs.
CHP Displaced Electricity	This is a function of the CIBSE AM12 model which identifies how much electricity will be generated by the CHP unit specified
Parasitic Electrical load adjustment	This is the amount of electricity generated by the CHP unit adjusted for a 1.9% electrical loss to account for the parasitic electrical load required to operate electro-mechanical infrastructure throughout the network. (DECC, *Assessment of the Costs, Performance, and Characteristics of UK Heat Networks*, 2015)
CHP Delivered heat	This is a function of the CIBSE AM12 model which identifies how much heat will be generated by the CHP unit specified
Network Heat loss adjustment	This is the amount of heat generated by the CHP unit adjusted for a 10% heat loss factor to account for the parasitic system heat losses which occur throughout the network infrastructure.(DECC, *Assessment of the Costs, Performance, and Characteristics of UK Heat Networks*, 2015)
System Energy Pricing	
Private Wire	Based on a modelled value at 95% of the DECC projected price scenario for 2018 (DECC Annex-f price growth assumptions 2013) on the basis that proposals would not be operational before 2018
Export	Based on an assumed grid export/power purchase price of 4.5p/kWh

Heat Sale (CHP & Boiler)	Based on comparative commercial gas unit rate at 3.7p/kWh with uplift adjustment for boiler maintenance & life-cycle replacement saving
Gas unit rate	Based on price indications of 2.53p/kWh received from independent energy brokers for gas purchase agreements at this volume/scale
Biomass rate	Based on quotes from potential suppliers averaging @ 4.6p/kWh for 20% MC pellet
Biomass RHi tariff rate (Tier 1 & 2)	Based on 2016 RHi biomass 250-999kW tariff rates: Tier 1 @ 5.24p/kWh, Tier 2 @ 2.27p/kWh Where top-up boiler capacity requirements are above the 999kW cut-off rate for the higher biomass RHi tariff it is assumed that a modular approach using multiple biomass boilers will be adopted to secure higher RHi rates.
Annual Standing Charge	Based on equivalent standing charge rate of £0.75/m2 for each building
System Opex Costs	
Network Maintenance	This is based on the aggregate of DECC benchmark figures of £0.6/MWh network maintenance, £9/MWh HIU maintenance, £3.4/MWh heat meter maintenance (DECC, *Assessment of the Costs, Performance, and Characteristics of UK Heat Networks*, 2015)
Bureaux Costs	This is based on the DECC benchmark figure of £16.9/MWh DECC, *Assessment of the Costs, Performance, and Characteristics of UK Heat Networks*, 2015)
Annual business rates	This is based on the DECC benchmark figure of £6/MWh DECC, *Assessment of the Costs, Performance, and Characteristics of UK Heat Networks*, 2015)
System Capital Costs	
Building Connections	Based on DECC benchmark of £25 per MWh annual consumption for non-domestic buildings DECC, *Assessment of the Costs, Performance, and Characteristics of UK Heat Networks*, 2015)
Transmission Mains	Based on DECC benchmark of £984/m (DECC 2015), this figure is supported by the findings of previous studies undertaken by Capita. DECC, *Assessment of the Costs, Performance, and Characteristics of UK Heat Networks*, (2015)
Distribution Mains	Based on a figure £600/m derived from the findings of previous studies
CHP	CHP costs are based on indicative pricing information from CHP providers of £500k per MW
Gas Boiler	Gas Boiler costs are based on £30k per MW – BSRIA Rules of Thumb Guidelines for Building Services 5th ed. (2011)
Biomass Boiler & assoc. plant	Biomass costs are based on detail provided by Biomass installers of £350k per MW including plant, Store, & associated civils costs
WHSP & assoc. plant	Large scale WHSP costs are based on indicative cost of £900k per MW provided by Star Refrigeration Ltd (Drammen large scale WHSP)
Plant balance of system (BOS)	Based on indicative costs from M&E installers of 16% of overall plant costs covering pumps, valves, and other electromechanical controls infrastructure required within the energy centre
Energy Centre (EC) building size	The size of the energy centre is derived using a minimum footprint of 100m2 with additional adjustment of 100m2 per 1MW plant capacity above an initial 1MW. A larger 1.2 adjustment factor is applied to the Biomass system due to additional space requirements dictated by fuel intake and ash recovery.
Energy Centre (EC) building cost	Based on BCIS £1,136 per m2 build cost for non-conditioned commercial plant & facilities accommodation
Thermal Store Size m3	Based on approximate requirement of 22m3 to supply 1MWh thermal energy (Tyndall Centre paper on Thermal Storage Jan 2013)
Thermal Store Cost	Based on DECC benchmark cost for Thermal Store of £843/m3 DECC, *Assessment of the Costs, Performance, and Characteristics of UK Heat Networks*, 2015)

Appendix 2: Risk Assessment

Risk ref.	Description	Likelihood (1:5)	Impact (1:5)	Risk	Recommended Action/Comments/Planned Mitigation	Likelihood (1:5)	Impact (1:5)	Residual Risk
Strategic risks identified at commencement of Master-Planning								
1	Reliance on 3rd Party consumption data from multiple sources - resulting in insufficient detail for technical design	**4**	**4**	**High**	Adopt an approach of modelling this data using the appropriate industry benchmarks. NTC to issue letter of Authority to external organisations and approval from external organisations to deal directly with suppliers.	**1**	**2**	**Acceptable**
2	Provision of data by 3rd Parties - M&E building information (External Organisations) - External organisations may not be willing to share detailed building information	**3**	**4**	**Med**	Where information not available we will advise on the suitability of desktop modelling based on recognised best practice provided by appropriate industry bodies such as CIBSE, BRE, and RIBA.	**4**	**3**	**Undesirable**
3	Poor engagement from external organisations - Soft market testing	**4**	**3**	**Med**	We would anticipate that the Council will already have strong relationships with the appropriate external organisations within their borough via existing networks - NTC to support facilitation of soft market testing by engaging with external organisations via existing networks.	**2**	**2**	**Acceptable**
4	Applications to utility providers - Timescales to complete statutory undertakings applications, should the completion of formal applications be deemed a requirement	**3**	**4**	**Med**	Where the brief refers to ‘appropriate initial applications to relevant utility providers’ we take this to mean holding initial informal discussions with relevant utility providers	**1**	**3**	**Acceptable**
Cross cutting risks relevant across all Master-Planning Clusters								
5	Insufficient/unavailable planning detail in the case of potential relevant new developments – Insufficient detail (dwelling space standards) for Murton Gap site identified at Heat Mapping phase resulting in inability to include this site in pre-feasibility modelling	**4**	**5**	**High**	Maintain close consultation with housing/planning teams liaising with developer consortium to ensure loads can be modelled once detail available. Provide narrative in report to this effect	**1**	**1**	**Acceptable**
6	Lack of availability of consistent half-hourly consumption data for external buildings will limit the level of complexity/detail achievable in network modelling – Min & Max loads, network sizing	**4**	**4**	**High**	Limit modelling to benchmark derived consumption where half-hourly data not available. NTC BMS operation used to derive annual building profiles – in keeping with HNCoP 2.1 best practice – revisit at feasibility where necessary	**2**	**4**	**Undesirable**
7	Lack of availability of consistent half-hourly consumption data for external buildings will limit the ability to accurately model thermal storage	**4**	**4**	**High**	Highlight data/detail discrepancies in report. Identify inherent storage capacity in network & quantify. Explore additional storage	**2**	**4**	**Undesirable**

	requirements/performance				options/performance based on system capacities/hourly heat output – revisit at feasibility where necessary			
8	Lack of availability of consistent half-hourly consumption data for external buildings will limit the ability to accurately model system operating temperatures, Delta T, Delta P	**4**	**4**	**High**	Clarification outstanding. In absence system temperatures have been modelled on known building system operating temperatures – revisit at feasibility where necessary	**3**	**4**	**Undesirable**
9	Available space for third party energy centre hosting – access to external buildings	**2**	**2**	**low**	NTC operational properties have been visited to assess space availability for potential energy centre hosting. Whilst no suitable sites have been found it has not been possible to gain access to non-NTC plant rooms – revisit at feasibility where necessary	**2**	**2**	**Acceptable**
Cluster Specific issues identified during Master-Planning								
11	A19 North – limited land availability for energy centre. The only available site is a fair way from the main network infrastructure.	**3**	**3**	**Med**	Land ownership/availability constraints have been highlighted and assessed. With no other available sites or opportunities for 3rd party hosting possible mitigations are limited. The proposal does still achieve a number of financial viability criteria.	**2**	**3**	**Acceptable**
12	A19 North –Building ownership concerns – many buildings in this commercial business park are owned by institutional landlords (including NTC buildings) – obtaining firm commitments could be challenging	**4**	**4**	**High**	Building ownership constraints have been highlighted and the risks communicated in the report – continued analysis of this proposal at feasibility stage should be subject to an expression of interest from key building landlords	**3**	**4**	**Undesirable**
13	A19 North –This proposal is heavily reliant on modelled heat load	**3**	**4**	**Med**	In the absence of consistent half hourly data proposals at this pre-feasibility stage can only be assessed using modelled load – risks should be clearly highlighted and revisited at feasibility stage where necessary.	**3**	**4**	**Undesirable**
14	A19 North –This proposal is reliant on external take-up of private wire load (NTC consumption = 88% of system electricity generation)	**2**	**4**	**Med**	Private wire electricity sale is competitively priced within the financial modelling suggesting this is a relatively safe assumption – direct contact could be made where relevant at feasibility where necessary to test interest.	**2**	**4**	**Undesirable**
15	A19 South (Phase 2) –This phase of the proposal is completely reliant on modelled heat load	**4**	**4**	**High**	In the absence of consistent half hourly data proposals at this pre-feasibility stage can only be assessed using modelled load –	**3**	**3**	**Undesirable**

					risks should be clearly highlighted and revisited at feasibility stage where necessary.			
16	A19 South (Phase 2) –This phase of the proposal is reliant on external take-up of private wire load (NTC consumption = 32% of system electricity generation)	**2**	**4**	**Med**	Private wire electricity sale is competitively priced within the financial modelling suggesting this is a relatively safe assumption – direct contact could be made where relevant at feasibility where necessary to test interest.	**2**	**4**	**Undesirable**
17	Killingworth –reliance on modelled heat load	**3**	**4**	**Med**	In the absence of consistent half hourly data proposals at this pre-feasibility stage can only be assessed using modelled load – risks should be clearly highlighted and revisited at feasibility stage where necessary.	**3**	**3**	**Undesirable**
18	Killingworth – reliance on external take-up of private wire load (NTC consumption = 43% of system electricity generation)	**2**	**4**	**Med**	Private wire electricity sale is competitively priced within the financial modelling suggesting this is a relatively safe assumption – direct contact could be made where relevant at feasibility where necessary to test interest.	**2**	**4**	**Undesirable**
19	North Shields –reliance on modelled heat load (43% load risk)	**3**	**4**	**Med**	In the absence of consistent half hourly data proposals at this pre-feasibility stage can only be assessed using modelled load – risks should be clearly highlighted and revisited at feasibility stage where necessary.	**3**	**3**	**Undesirable**
20	North Shields – reliance on external take-up of private wire load (NTC consumption = 63% of system electricity generation)	**2**	**4**	**Med**	Private wire electricity sale is competitively priced within the financial modelling suggesting this is a relatively safe assumption – direct contact could be made where relevant at feasibility where necessary to test interest.	**2**	**4**	**Undesirable**
21	North Shields –Potential utilities congestion	**3**	**4**	**Med**	Utilities constraints to be explored further at feasibility stage as necessary – visual survey, or informal consultation with providers	**2**	**3**	**Acceptable**
22	Wallsend –reliance on modelled heat load (33% load risk)	**3**	**4**	**Med**	In the absence of consistent half hourly data proposals at this pre-feasibility stage can only be assessed using modelled load – risks should be clearly highlighted and revisited at feasibility stage where necessary.	**3**	**3**	**Undesirable**

23	Wallsend –Potential utilities congestion	**3**	**4**	**Med**	Utilities constraints to be explored further at feasibility stage as necessary – visual survey, or informal consultation with providers	**2**	**3**	**Acceptable**
24	Wallsend –Potential land constraints – distribution access over church land to residential care homes	**2**	**2**	**low**	Land constraints to be explored further at feasibility stage as necessary – visual survey, or informal consultation church authorities – explore re-routing options as necessary	**1**	**2**	**Acceptable**
25	Whitley Bay –reliance on modelled heat load (50% load risk)	**3**	**4**	**Med**	In the absence of consistent half hourly data proposals at this pre-feasibility stage can only be assessed using modelled load – risks should be clearly highlighted and revisited at feasibility stage where necessary.	**3**	**3**	**Undesirable**
26	Whitley Bay – reliance on external take-up of private wire load (NTC consumption = 28% of system electricity generation)	**2**	**4**	**Med**	Private wire electricity sale is competitively priced within the financial modelling suggesting this is a relatively safe assumption – direct contact could be made where relevant at feasibility where necessary to test interest.	**2**	**4**	**Undesirable**

Appendix 3: Initial Submission (04/04/16): A19 South Proposal with NWL Waste Heat Analysis

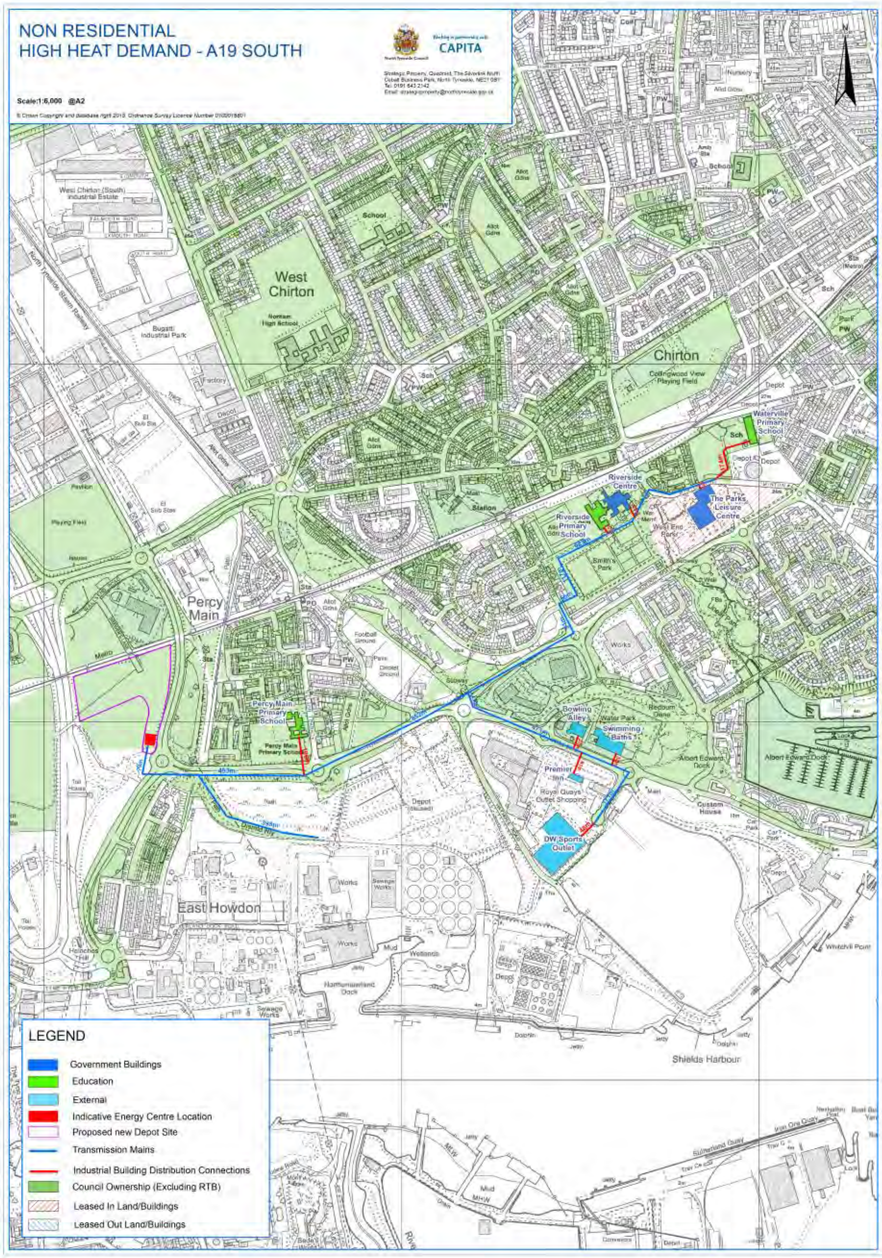

Figure 96: Non Residential Heat Demand - A19 South

North Tyneside Council

Working in partnership with CAPITA

6.3.1 A19 South System – Anchor Buildings and Energy Centre Location:

Table 43: A19 South - Anchor Building Properties

Building	Size m2	Annual Heat demand (MWh)	Data Source	Comments
Percy Main Primary School	2482	210.53	Actual consumption data from NTC EM System	Large older Secondary school with lower summer baseload & no heating load from June to September
Riverside Primary School	2249	336.87	Actual consumption data from NTC EM System	Medium sized modern Primary school with lower summer baseload & no heating load from June to September
Waterville Primary School	1569	138.56	Actual consumption data from NTC EM System	Smaller modern Primary school with lower summer baseload & no heating load from June to September
Riverside Children's Centre	3865	638.12	Actual consumption data from NTC EM System	Large mixed-use children's centre with extended opening hours and no heating load in July & August
Parks Leisure Centre	6916	787.17	Actual consumption data from NTC EM System	Dry leisure centre with high DHW demand and fairly constant seasonal load profile.
Wet'n'Wild Leisure Centre	3574	343.10	2013 EPC rating	Wet leisure centre/water-park with high DHW demand and continuous heating load.
Starbowl Centre	2748	235.23	2013 EPC rating	Indoor Bowling ally with no heating load in July & August
Premier Inn Hotel	1318	348.06	Modelled on CIBSE TM46 using EPC & GIS measurement	Compact Modern budget Hotel with continuous DHW load, seasonal cooling load, and no heating load in July & August.
DW Fitness Soccer dome	9525	662.94	Modelled on CIBSE TM46 using EPC & GIS measurement	Large mixed-use retail with large food store & smaller retail parade – assumed no heating load in July & August

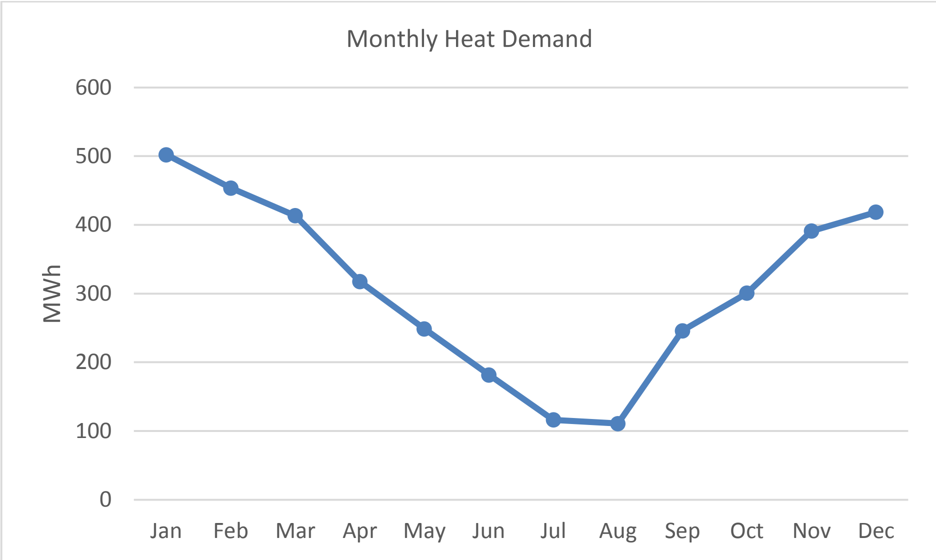

Figure 97: A19 South - Monthly Heat Demand

The A19 South cluster includes a number of buildings with a diverse range of uses. With three primary schools there is a noticeable seasonal effect on the annual heat demand across the cluster, with a noticeable drop in demand in July and August as a result of summer school closures as identified in the graphic above. This is offset to some extent by the two dry leisure centres and the Wet'n'Wild wet leisure centre/water park which support the base-load over the warmer summer months. The higher demands are provided by the Parks Leisure centre, the Children's centre, and the DW Fitness Soccer dome.

Five of the nine buildings within the cluster are NTC operational buildings with actual consumption data available, with the remaining for buildings reliant on derived consumption data, two of these buildings would be significant anchors within the network so further attention at the feasibility stage will be required to test the benchmark outputs. To highlight this, the demand from the wet'n'wild leisure centre seems low given the type of building use, the figure is derived from the 2013 EPC rating and the measured floor area recorded on the EPC certificate, rather than calculated using the appropriate benchmark. As the EPC constitutes a measured survey, undertaken in-line with a nationally agreed methodology, the outputs have been used to derive the building's consumption in preference of a benchmark approach. However, a further check should be undertaken prior to detailed feasibility analysis.

Figure 98: A19 South - Aerial Satellite View

As identified on the proposal map there is a good level of NTC land ownership within the proposal area with the majority of the proposed anchor buildings accessible via NTC owned land. In addition to the preferable land ownership situation the above satellite image demonstrates that there is considerable amounts of green space in many areas which supports flexibility in terms of network routing as well as associated opportunities to value-engineer network infrastructure costs.

The satellite image below identifies a large site on the Western edge of the image which is currently the preferred option for the relocation of the Council's depot site. Given the sites location as the closest feasible NTC site in proximity to the source of waste heat from the NWL Howdon treatment works this is the location that has been chosen for the proposed energy centre. The site could comfortably accommodate 200+m2 energy centre, along with any additional requirement for biomass or thermal storage.

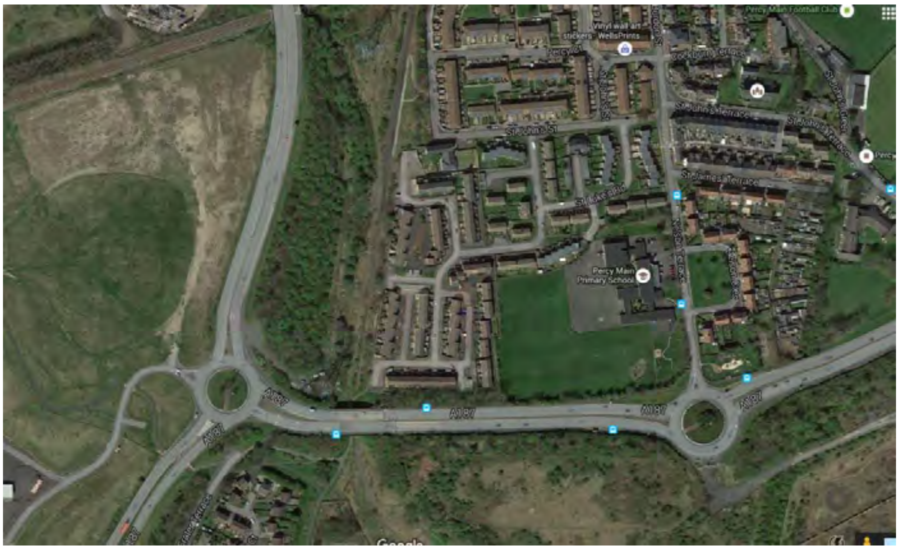

Figure 99: A19 South – Aerial Satellite View (2)

The NTC Asset Management and NTC Energy Management function have confirmed that the three NTC operational buildings within the cluster are heated by traditional medium temperature wet heating systems operating at approximately 80°C flow with 70°C return. Domestic hot water is supplied by with calorifiers operating at 60°C flow and 50°C return. Further detail on the non-NTC buildings will have to be sought at the feasibility stage however, given the age and type of construction of the external buildings it is assumed that traditional wet heating systems are in use. On this basis it is assumed that all buildings are suitable for connection to a district heating network and that none of the buildings identified present insurmountable constraints in terms of the proposal.

6.3.2 System configuration and Technology Options:

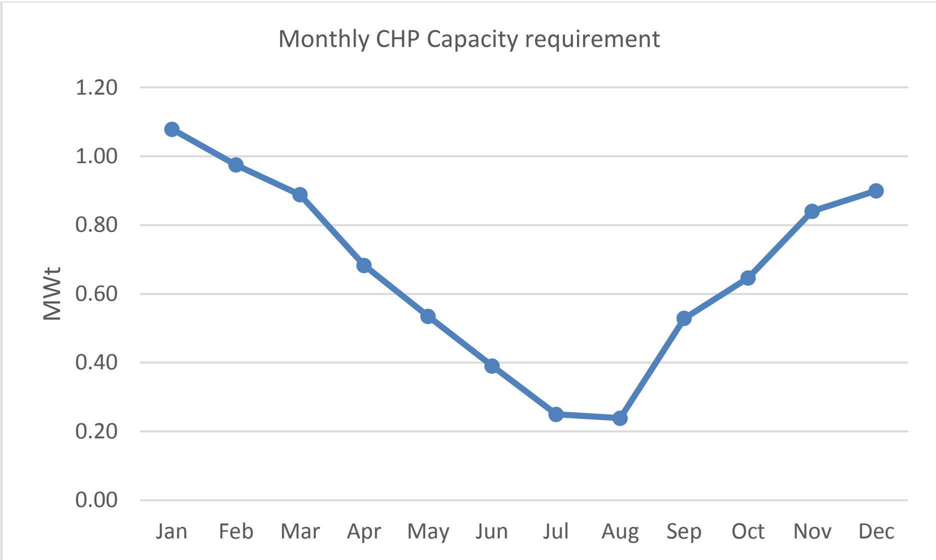

Figure 100: A19 South - Monthly CHP Capacity Requirement

With the lowest monthly heat & DHW demand across the cluster occurring in August, the corresponding base-load of 110.93 MWh would dictate a maximum CHP size of 260kWt/2000kWe, with a top-up boiler capacity requirement of 1.34MWt for gas fired boilers, or 1.46MWt for Biomass boilers. On a base-load CHP sizing basis only 36% of the annual heat demand would be served by the CHP unit with the remainder being provided by the back-up boilers.

If a modular CHP approach were adopted a the smaller base-load CHP unit could be supported a larger 440kWt/340kWe CHP unit to provide a combined capacity of 700kWt/550kWe which would provide approximately 77% of the annual heat demand and reducing back-up boiler capacity requirement to 710kWt for gas fired boilers, or 770kWt for Biomass boilers. Further to this the modular CHP approach would generate an additional 1,295.91 MWh of power for sale via private wire, or export.

With an indicative waste heat load of 2MW at approximately 80°C available from the NWL sewage treatment site at Howdon an outline system has been modelled to assess the value of this potential free heat within the context of this proposal. A small CHP unit has been sized to provide the 70MWh per annum of power required to transport the available heat throughout the network, apart from the heat generated by this unit the remaining heat demand is served by the waste heat available. On this basis a 20kWe/24kWt unit would be required to service the network.

For both the gas only, and Biomass system options electricity sale via a Private-wire only, and export only approaches have been modelled to establish the value of the different approaches. Under the waste heat scenario there is only around 30MWh of excess power generated by the CHP unit (due to sizing tolerances), therefore the income contribution from private wire or export sale is minimal.

To connect the potential anchor buildings identified, a total 3,188 of transmission mains would be required at a capital cost of £3,137,000 with a further 555m of distribution mains to individual buildings at a cost of £32,800, and an overall cost of 856,160 for building connections.

Total capital costs for the gas only network including network infrastructure, plant and energy centre costs comes to £4,630,590. Whereas the total cost for the biomass top-up system comes in at a higher total capital cost of £4,949,269 due to the higher cost of biomass heating plant and ancillary equipment.

Table 44: A19 South Table Cost Summary

System	Network Infrastructure costs (£)	Energy Centre & Plant costs (£)	Potential CO2 abatement (tonnes p/a)	Total costs (£)
Gas only	4,325,960	304,630	1,613.05	**4,630,590**
Gas CHP biomass top-up	4,325,960	623,309	1,773.98	**4,949,269**

Table 45: A19 South System Annual Income Profile

System Annual Income profile		
Income Item	**Gas Only**	**Gas-Biomass**
Energy Sales (Private Wire only)	494,450	494,450
Energy Sales (Export Only)	338,355	338,355
RHI Income	-	45,589
Standing Charge	25,685	25,685
Business rates (Cost not income)	22,220	22,220

6.3.3 Network options – Financial Assessment:

A techno-economic analysis is presented for the A19 South cluster for the following five technology options:

1. Gas CHP unit using private wire electrical distribution
2. Gas CHP unit with electricity exported to the national grid
3. Gas CHP unit plus biomass heat generation with private wire electrical distribution
4. Gas CHP unit plus biomass heat generation with electricity exported to the national grid
5. NWL Waste heat system with CHP

Table 46: A19 South Cluster Summary Table

A19 South Cluster				
		Appraisal (years)	**IRR**	**NPV @ 6%**
Gas CHP Private Wire	Without TS	25	-	-2,501,085
		40	-	-2,144,174
	With TS	25	-	-3,048,625
		40	1%	-2,634,493
Gas CHP Export	Without TS	25	-	-4,349,248
		40	-	-4,345,572
	With TS	25	-	-5,040,059
		40	-	-5,006,544
Gas CHP + Bio Private Wire	Without TS	25	-	-2,563,773
		40	-	-2,161,383
	With TS	25	-	-3,172,145
		40	1%	-2,724,160
Gas CHP + Bio Export	Without TS	25	-	-4,411,937
		40	-	-4,362,781
	With TS	25	-	-5,163,579
		40	-	-5,096,211
Waste Heat	Without TS	25	-	-3,220,519
		40	-	-3,008,456

Table 25 above provides an overview of the financial performance of the four system options for the A19 South network proposal at an assumed public sector borrowing rate of 6%. As the table identifies, neither of the export based systems return a positive NPV suggesting that they are not viable given the capital investment required.

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Following a private wire electricity sale approach, neither the gas only nor the biomass backup system options would be viable at the 6% target rate. The Gas-Biomass approach returns a slightly higher NPV over both the 25 and 40 year appraisal periods despite the higher capital costs.

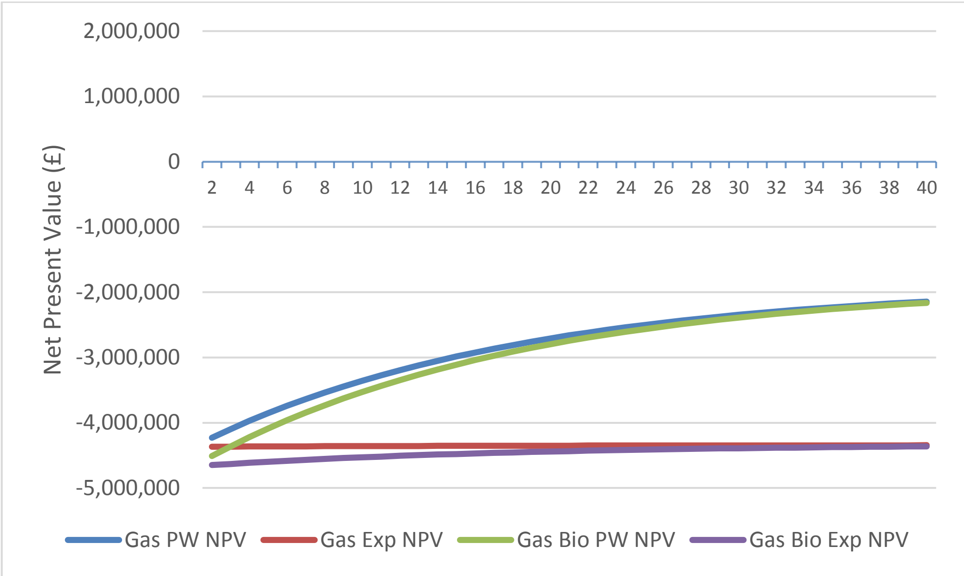

Figure 101: A19 South Cluster - Outline Cost Evaluation (NPV discount rate @ 6%)

As the chart above demonstrates, none of the systems generate a positive NPV position having failed to repay the required capital outlay across the longer 40 year appraisal period. This suggests that none of the network would operate profitably at any point throughout the longest 40 year period. This suggests that additional gap funding (to reduce capital expenditure) would be required in order to make any proposal viable.

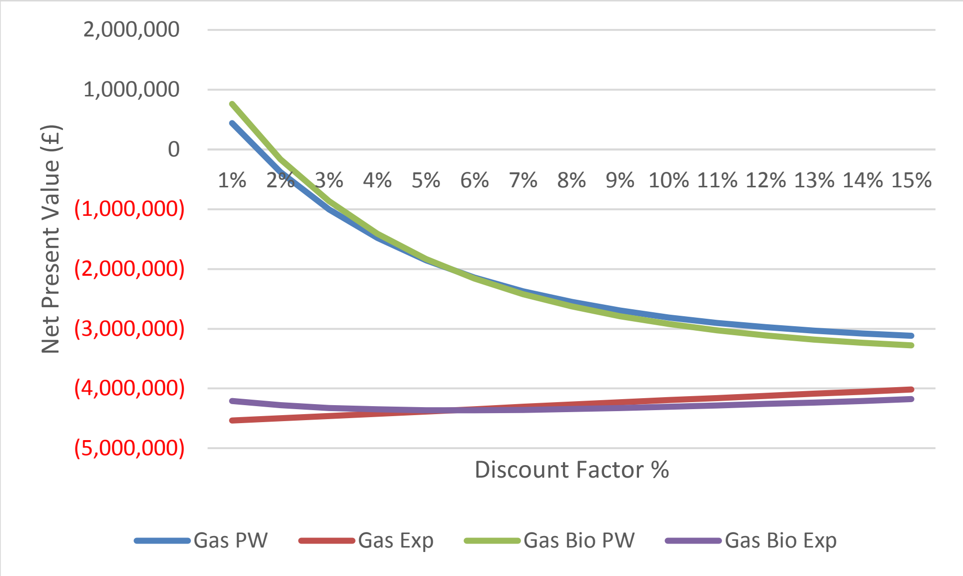

Figure 102: A19 South Cluster - NPV DCF Sensitivity Analysis

The figure above demonstrates the change in NPV for a given discount factor. The DCF essentially represents the cost of borrowing. It is therefore possible to ascertain the viability of the system across a range of borrowing rates.

As noted previously, public sector funded projects are typically financed at a cost of borrowing of around 6%. Conversely, it is unlikely that private sector could be secured from the open market at a borrowing rate of less than 10%.

As the chart above demonstrates, no proposal returns a positive NPV at a 10% discount factor, suggesting that further cost reduction or capital offset of between £3m to £4.5m would be required to make these proposals robust enough to secure private sector funding.

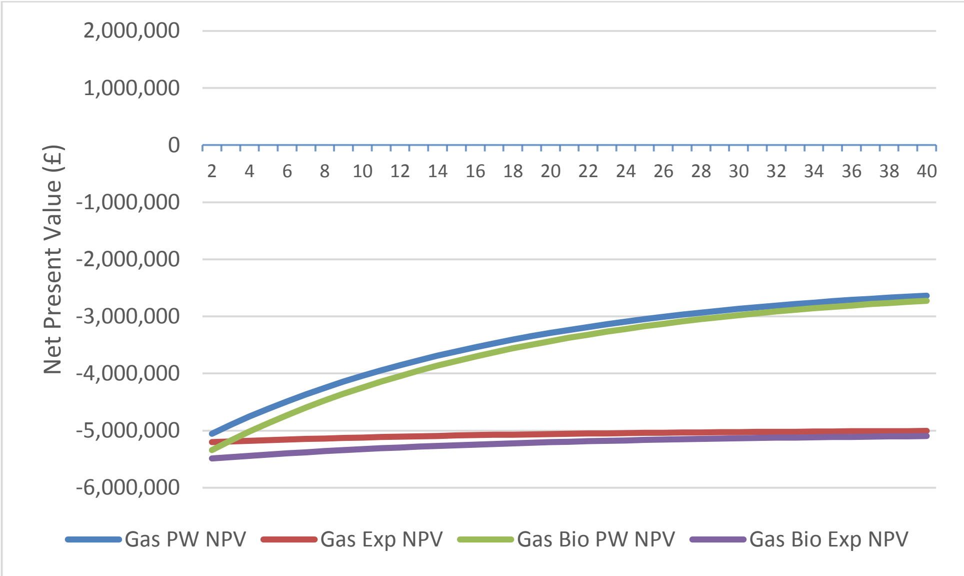

Figure 103: A19 South Cluster with Thermal Store - Outline Cost Evaluation (NPV discount rate @ 6%)

It is evident from the figure above that the additional capital cost of thermal storage neither improves the financial performance of any of the proposals, nor could the additional cost be supported. No system options could deliver a positive NPV under a thermal store scenario.

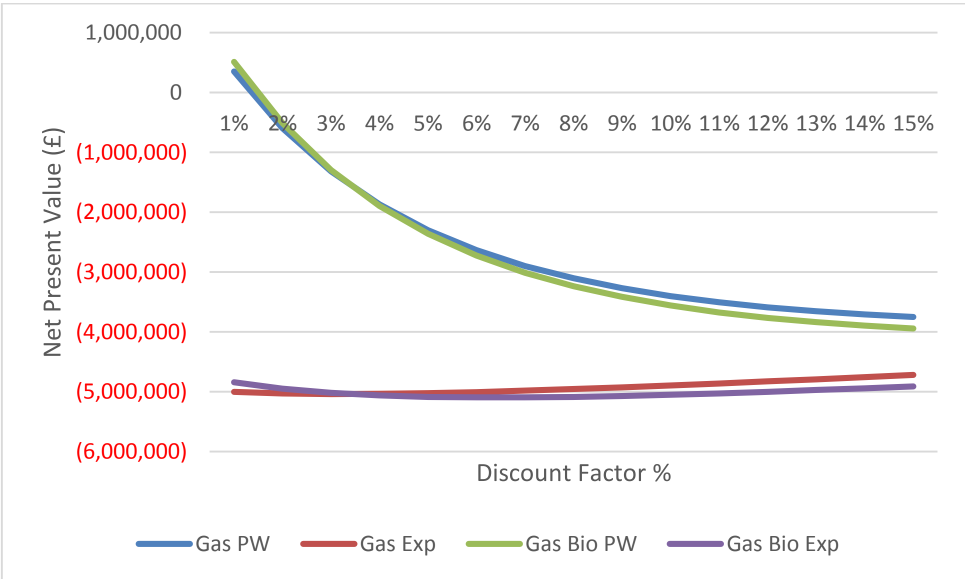

Figure 104: A19 South Cluster with Thermal Store - NPV DCF Sensitivity Analysis

Further to the adverse effect on payback the figure above suggests that all thermal storage options fail to meet the threshold required for private sector financing or public sector funding support.

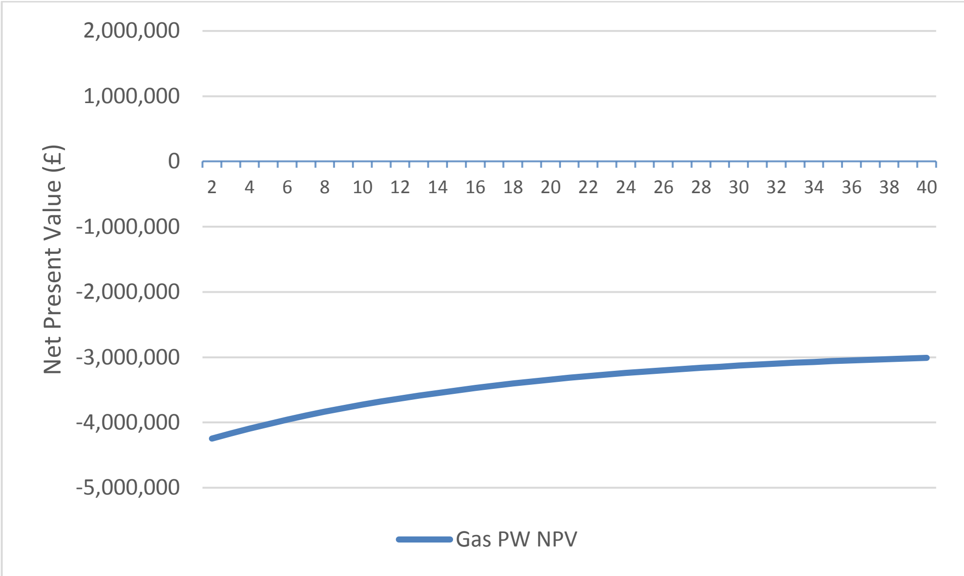

Figure 105: A19 South - Gas PW (NPV discount rate @ 6%)

As the figure above demonstrates, the availability of a significant waste heat resource does little to improve the financial performance of the network when the sale of heat provides the only source of revenue. This is further reflected by the figure below which highlights the borrowing scenario under a waste heat proposal where electricity revenues are removed from the model.

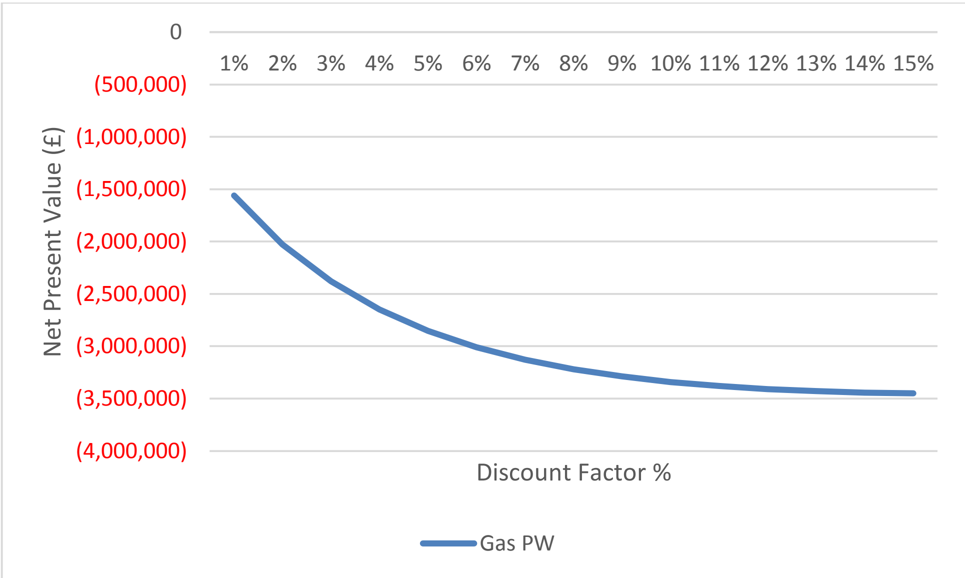

Figure 106: A19 South - Gas PW - NPV DCF Sensitivity Analysis

In summary the financial analysis suggests that the A19 South network proposal is not financially robust, failing to achieve a positive NPV across any technology/configuration. In addition to this securing either public or private sector funding support would be extremely challenging without significant capital re-gearing.

Contact

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