FICHTNER
Consulting Engineers Limited

Tees Valley Energy Recovery Facility

Viridor Tees Valley Ltd

CHP Assessment

ENGINEERING CONSULTING

Document approval

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Management Summary

Viridor Tees Valley Limited (herein referred to as Viridor) (the Applicant) is applying to the Environment Agency (EA) under the Environmental Permitting (England and Wales) Regulations 2016 (EPR) for an environmental permit to operate an Energy Recovery Facility (ERF), (herein referred to as the Facility), in Grangetown, Redcar & Cleveland Borough Council.

The Facility will comprise of an Energy Recovery Facility and associated infrastructure. The Facility will be fuelled by pre-processed municipal and commercial & industrial non-hazardous waste (herein referred to as waste). The waste accepted at the Facility will have been pre-treated off-site to remove recyclates.

Assuming a design NCV of 10.25 MJ/kg, the Facility will process approximately 429,197 tonnes per annum (at the design capacity of 52.6 tph, assuming 8,147 hours availability).

The maximum annual throughput is 510,000 tonnes per annum assuming 8,760 hours operation per annum at 110% of the design point. However, this does not account for periods of start up, shut down and other periods of non-availability. Allowing for these periods, the maximum capacity of the Facility will be approximately 495,000 tonnes per annum.

The Facility has been designed to export power to the National Grid. The Facility will generate approximately 48.2 MW_e of electricity in full condensing mode and with average ambient temperature. The Facility will have a parasitic load of approximately 4.63 MW_e. Therefore, the export capacity of the Facility, with average ambient temperature, is approximately 43.6 MW_e.

The Environment Agency (EA) Combined Heat and Power (CHP) Ready Guidance requires Best Available Techniques (BAT) to be demonstrated by maximising energy efficiency. Following screening of potential heat consumers and development of a network heat demand profile, it has been established that technically feasible opportunities exist to export an annual average heat load of up to 5.46 MW_{th}, and, when accounting for consumer diversity and heat losses, a peak load of 11.55 MW_{th}.

The Facility will be technically capable of meeting these heat loads, subject to economic feasibility. The maximum heat capacity of the Facility will be confirmed during detailed design and will be set as a minimum to meet the requirements of the heat consumers identified.

While the quantity of heat demand identified is sufficient to achieve Primary Energy Savings (PES) in excess of the 10 % technical feasibility threshold, it is not sufficient to be deemed ‘Good Quality’ in accordance with the CHP Quality Assurance (CHPQA) scheme. At the proposed heat network load, PES was calculated to be 23.56 % and the CHPQA Quality Index (QI) score was 63.9. A QI score of 105 is required at the design stage to be deemed ‘Good Quality’. The highly onerous new efficiency criteria set out in the latest CHPQA guidance means that it is unlikely that any energy recovery facility will now reach ‘Good Quality’ status.

In accordance with Article 14 of the Energy Efficiency Directive, a cost-benefit assessment (CBA) of opportunities for CHP is required when applying for an Environmental Permit (EP). An assessment of the costs and revenues associated with the construction and operation of the proposed heating network has been undertaken. This has been inputted into a CBA in accordance with the draft Article 14 guidance document issued by the EA. The results of the CBA indicate that the nominal project internal rate of return and net present value (before financing and tax) over 30 years are 9.6 % and -£5.02 million respectively. Although a reasonable IRR is achieved the NPV is negative indicating the project would not be profitable. Therefore, it is considered that the proposed heat network does not yield an economically viable scheme in its current configuration. However, the economic feasibility of the scheme will be reassessed in the future when there is further certainty regarding heat loads. This future assessment will also account for any subsidies that might become available in the future to support the export of heat.

Based on these findings, it is considered that construction as CHP-Ready will demonstrate BAT for the Facility. A CHP Ready Assessment form has been completed and is provided in Appendix D of this report.

CHP-Ready means that the Facility will be able to export heat in the future with minimum modification. This will be achieved by virtue of having steam capacity designed into the turbine bleed and safeguarded space to house CHP equipment.

Contents

1 Introduction

1.1 Background

Viridor Waste Management Ltd is developing the Tees Valley Energy Recovery Facility (the 'Facility') to incinerate incoming non-hazardous residual waste. The Facility will be located at the site of a former British Steel works in Grangetown, a large industrial brownfield site in Redcar and Cleveland Borough Council in an area known as Grangetown Prairie.

1.2 Objective

The principle objectives of this study are as follows:

1. Prepare a CHP Assessment in line with the Environment Agency (EA) guidance on cost-benefit assessment (CBA) for combustion installations, which will support an Environmental Permit (EP) application.
2. Provide a technical description of the proposed Facility and heat export infrastructure.
3. Calculate heat demands based on identified heat consumers and assess the feasibility of connecting identified heat consumers to the network.
4. Based on the heat loads anticipated for the outline solution identified, calculate relevant energy efficiency measures to demonstrate legislative compliance.
5. Produce provisional pipe routing drawing from the Facility to the likely heat consumers.
6. Conduct an economic assessment feeding into the CBA as required under Article 14 of the Energy Efficiency Directive.
7. Produce a CHP-Ready Assessment as required under the EA CHP-Ready guidance, including a clear statement on best available techniques (BAT), combined heat and power (CHP) envelope and the CHP-Ready Assessment form.

1.3 The Location

The Facility will be located on land within the South Tees Development Corporation (STDC) area, which comprises 4,500 acres (1,800 hectares) of land that forms part of the STDC's Regeneration Master Plan.

The proposed ERF site occupies a 25-acre (10 hectare) site situated at the southwestern corner of the STDC area, within the Grangetown Prairie Zone. The site lies 1.2km south of the River Tees and approximately 4miles to the north-east of Middlesbrough Town centre. The Facility will be located at an approximate national grid reference NZ 54436 21340.

The Facility is bounded to the north by the main Middlesbrough to Redcar railway line, to the east by the site of Lackenby steel works, to the south by industrial units and beyond them the A66 road and to the west by various industrial units. Access to the site will be via a new site access on the corner of Eston Road that will serve a new internal highway network for the Grangetown Prairie plots. This access will be constructed as part of the enabling works for all development plots by STDC. The site is brownfield land which has been cleared and was once dominated by industrial buildings at the heart of the steel making industry on Teesside. Some industrial buildings /plant still surround the Grangetown Prairie site on its the south, east and western boundaries.

A site location plan and Installation Boundary drawing are presented in Appendix A.

2 Conclusions

2.1 Technical Solution

The Facility will have a gross electrical output of 48.2 MWe, (design when operating in fully condensing mode), with a parasitic load of 4.63 MW_e with the balance exported to the National Grid. Therefore, the Facility will export approximately 43.6 MW_e in fully condensing mode. The Facility will be designed with the capability to export up to 12 MW_{th} of heat to local consumers. The maximum heat capacity will be subject to the requirements of the heat consumers and confirmed during the detailed design stage. Based on the heat network identified within this Heat Plan, the average heat load is expected to be 5.46 MW_{th}, resulting in an average gross electrical generation of approximately 47.4 MW_e.

A number of options for heat recovery and export from the Facility are available. Given the requirements of the heat consumers (discussed subsequently), flexibility in terms of export temperatures and capacity, and the associated environmental benefits, steam extraction from the turbine is considered the most favourable solution. It is proposed that heat will be transferred to a closed hot water circuit via a series of condensing heat exchangers and supplied to consumers through a pre-insulated buried hot water pipeline, before being returned to the Facility for reheating. This technology is well proven and highly efficient.

2.2 Potential Heat Consumers

A review of the potential heat demand within a 15 km radius of the Facility has been undertaken in accordance with the requirements set out in Section 2 of the EA’s draft Article 14 guidance. Physical constraints imposed by local infrastructure has a significant impact on which consumers can viably be connected. Both river and rail crossings exist in the area surrounding the Facility and may present obstructions to connect some consumers. Engineering a bridge crossing will likely require detailed structural assessments and the consent of the bridge owner. Trenching in road crossings will require traffic management and permission from the highway authority. Following screening of potential heat consumers, the identification of existing heat demands has centred on nearby industrial and commercial users, as the benefits of providing heat to large nearby premises is generally more financially viable than supply to multiple smaller consumers at further distances.

Heat consumers have been identified using publicly available data in the National Comprehensive Assessment, heat mapping tools and satellite imagery. The identified existing local heat consumers include offices and warehouses in many industrial estates located at pipeline distances of between 0.43 km and 4.5 km surrounding the Facility.

Several large heat consumers (point heat demands greater than 5 MW_{th} as defined by the UK CHP Development Map) have been identified within the specified 15 km search radius. The large consumers identified were located a significant distance away from the Facility and scattered at different locations and would require a prohibitively costly pipe network to connect to each consumer. Therefore, these large heat consumers have been discounted. Nearby Wilton Power station, which is operated by Sembcorp has its own CHP plant therefore it has also been discounted.

2.3 Heat Network Profile

The heat demand of the preferred heat consumers has been estimated based on generic heat demand profiles. The average and diversified peak heat demand of the proposed heat network has been estimated to be 5.46 MW_{th} and 11.55 MW_{th} respectively, with an annual heat demand of 77,787 MWh/annum.

A heat demand profile has been developed to assess diurnal and seasonal variation in heat demand for the proposed heat network. The heat demand profile indicates that base and peak loads can be met by the Facility independently. Detailed techno-economic modelling will be undertaken when there is a better understanding of consumer heat demands.

2.4 Economic Assessment

The costs and revenues associated with the construction and operation of the proposed district heating network has been undertaken. This has been inputted into the EA's CBA template. The CBA takes account of heat supply system capital and operating costs, heat sales revenue and lost electricity revenue as a result of diverting energy to the heat network.

The results of the CBA indicate that the estimated £13.94 million capital investment will not be offset by heat sales revenue. The nominal project internal rate of return (before financing and tax) over 30 years is projected as 9.6 %, with a net present value of -£5.02 million.

Given the current Renewable Heat Incentive (RHI) scheme is due to end in March 2022, it is unlikely that the Facility will qualify for support under the scheme. The economic feasibility of the scheme will be reassessed in the future when there is a better understanding of heat demands considering any subsidies that support the export of heat.

As construction of a district heating network is currently not economically feasible, the Facility will be built to be CHP-Ready. As such, the Facility will meet the requirements of BAT tests outlined in the EA CHP Ready Guidance.

2.5 Energy Efficiency Measures

In order to qualify as technically feasible under the draft Article 14 guidance, the heat demand must be sufficient to achieve high efficiency cogeneration, equivalent to at least 10 % savings in primary energy usage compared to the separate generation of heat and power. When operating in fully condensing mode (i.e. without heat export) the Facility will achieve a primary energy saving (PES) of 22.12 %, which is in excess of the technical feasibility threshold defined in the draft Article 14 guidance. Adding the proposed heat network will result in PES of 23.56 % which is in excess of the technical feasibility threshold and would therefore be technically feasible to supply.

To be considered 'Good Quality' CHP under the CHPQA scheme, the quantity of heat exported to a heat network must be sufficient to achieve a Quality Index (QI) of at least 105 at the design stage (reducing to 100 at the operational stage). Changes to CHPQA guidance in December 2018 mean that the maximum QI score which could be achieved by the proposed heat network would be 63.9. On this basis, any heat network would not qualify as Good Quality CHP. The efficiency criteria set out in the latest CHPQA guidance means that it is unlikely that any energy recovery facility will now achieve 'Good Quality' status.

2.6 CHP-Ready Assessment

A CHP-Ready Assessment has been carried out as part of this Heat Plan and the completed CHP Ready Assessment form is provided in Appendix D. As the economic case for the proposed heat network is not economically viable, constructing the Facility as CHP Ready is considered to represent BAT.

As CHP-Ready, the Facility will be designed to be ready, with minimum modification, to supply heat in the future. The EA CHP Ready Guidance in February 2013 states that given the uncertainty of future heat loads, the initial electrical efficiency of a CHP-Ready facility (before any opportunities for the supply of heat are realised) should be no less than that of the equivalent non-CHP-Ready facility. The Facility will include steam capacity designed into the turbine bleeds to facilitate heat export in the future, and safeguarded space to house CHP equipment.

To satisfy the third BAT test on an ongoing basis, the Applicant is committed to carrying out periodic reviews of opportunities for the supply of heat to realise CHP.

3 Legislative Requirements

3.1 CHP-Ready Guidance

In February 2013, the EA produced a guidance note titled 'CHP Ready Guidance for Combustion and Energy from Waste Power Plants'[1]. This guidance applies to the following facilities, which will be regulated under the Environmental Permitting (England and Wales) Regulations 2016:

- new combustion power plants (referred to as power plants) with a gross rated thermal input of 50 MW or more; and
- new EfW plants with a throughput of more than 3 tonnes per hour of non-hazardous waste or 10 tonnes per day of hazardous waste.

The Facility will be regulated as a waste incineration facility with a throughput of more than 3 tonnes per hour. Therefore, the requirements of the CHP-Ready guidance will apply.

The EA requires developers to demonstrate BAT for a number of criteria, including energy efficiency. One of the principal ways of improving energy efficiency is through the use of CHP, for which three BAT tests exist. The first involves considering and identifying opportunities for the immediate use of heat off-site. Where this is not technically or economically possible, the second test involves ensuring that the plant is built to be CHP-Ready. The third test involves carrying out periodic reviews to determine whether the situation has changed and if there are opportunities for heat use off site.

3.2 Energy Efficiency Directive

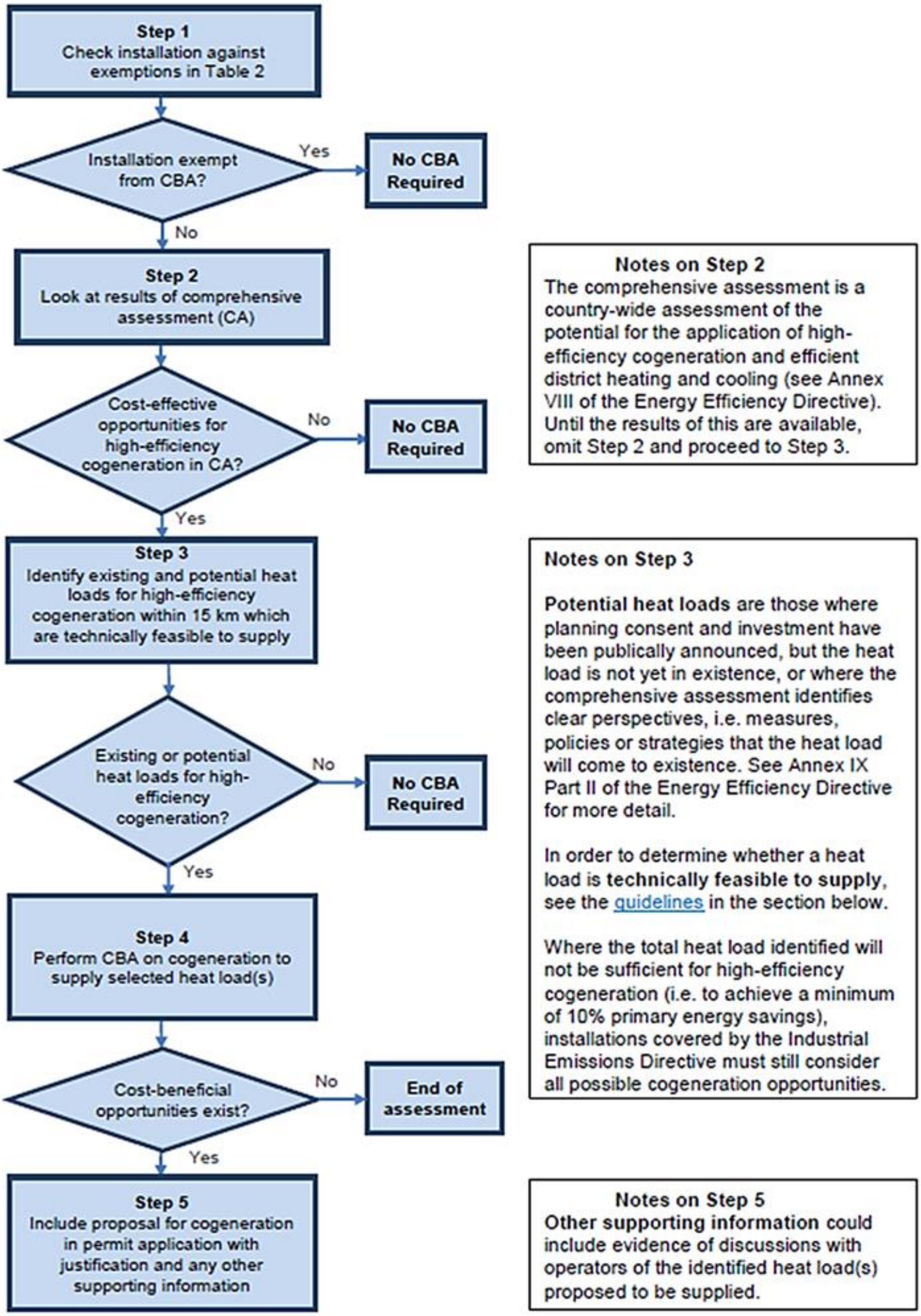
From 21 March 2015, operators of certain types of combustion installations are required to carry out a CBA of opportunities for CHP when applying for an EP. This is a requirement under Article 14 of the Energy Efficiency Directive and applies to a number of combustion installation types. As a new electricity generation installation with a total aggregated net thermal input of more than 20 MW, the Facility will be classified as an installation type 14.5(a).

In April 2015, the EA issued draft guidance on completing the CBA, entitled '*Draft guidance on completing cost-benefit assessments for installations under Article 14 of the Energy Efficiency Directive*'[2]. Figure 1 describes the process that must be followed for type 14.5(a) and 14.5(b) installations.

[1] CHP Ready Guidance for Combustion and Energy from Waste Power Plants v1.0, February 2013

[2] Draft guidance on completing cost-benefit assessments for installations under Article 14 of the Energy Efficiency Directive, V9.0 April 2015

Figure 1: CBA methodology for type 14.5(a) and 14.5(b) installations



4 Description of the Facility Technology

4.1 The Facility

The main activities associated with the Facility will be the combustion of incoming non-hazardous waste to raise steam and the generation of electricity in a steam turbine/generator.

The Facility includes two waste incineration lines, a waste reception hall, waste bunker, turbine hall, on-site facilities for the treatment or storage of residues and wastewater, flue gas treatment, stack, boiler, systems for controlling operation of the waste incineration plant and recording and monitoring conditions.

In addition to the main elements described, the Facility will also include weighbridges, water, auxiliary fuel and air supply systems, site fencing and security barriers, external hardstanding areas for vehicle manoeuvring, internal access roads and car parking, transformers, a grid connection compound, firewater storage tanks, offices, workshop, stores and staff welfare facilities.

The Facility will have a gross electrical output of 48.2MW_e, (design when operating in fully condensing mode), with a parasitic load of 4.63 MW_e with the balance exported to the local grid. Therefore, the Facility will export approximately 43.6 MW_e in full condensing mode. The facility is to be designed with the capability to export up to 12 MW_{th} of heat to local consumers. The maximum heat capacity will be confirmed during the detailed design stage and will be set as a minimum to meet the requirements of the heat consumers identified.

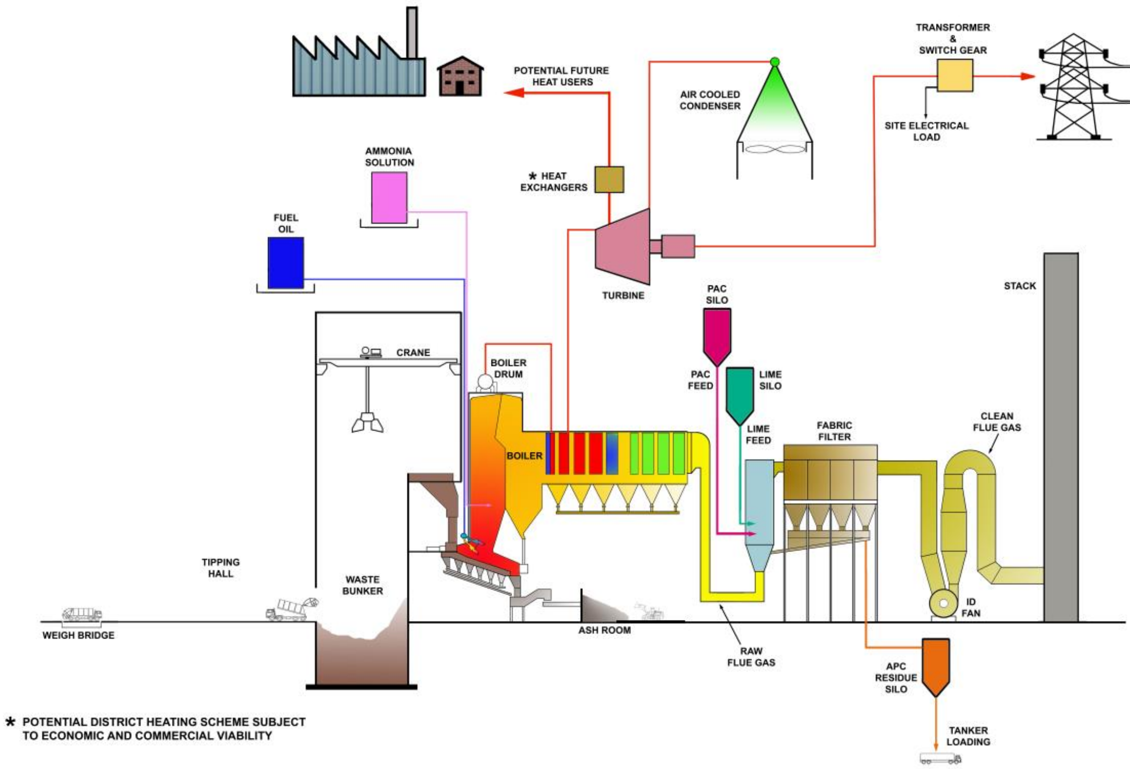
Based on the heat network identified within this Heat Plan, the average heat load is expected to be 5.46 MW_{th}, resulting in an average electrical export of approximately 42.9 MW_e. However, at the time of writing this report, there are no formal agreements in place for the export of heat from the Facility. The power exported may fluctuate as fuel quality fluctuates, and if heat is exported from the Facility to local heat users in the future.

The nominal capacity of the Facility will be approximately 52.6 tonnes per hour of mixed non-hazardous waste, with a nominal calorific value of 10.25 MJ/kg. The plant will have an estimated availability of around 8,147 hours. Therefore, the plant will have a nominal capacity of approximately 429,197 tonnes per annum. The maximum annual throughput is 510,000 tonnes per annum assuming 8,760 hours operation per annum at 110% of the design point. However, this does not account for periods of start up, shut down and other periods of non-availability. Allowing for these periods, the maximum capacity of the Facility will be approximately 495,000 tonnes per annum.

4.1.1 Combustion Process

Figure 2 is an indicative schematic of the combustion process that will be used in the Facility.

Figure 2: Process schematic



4.1.2 Energy Recovery

The heat released by the combustion of the incoming waste will be recovered by means of a water tube boiler, which is integral to the furnace and will produce (in combination with superheaters) at approximately 430 - 440°C and approximately 64 bar(a). The steam from the boiler will then feed a high-efficiency steam turbine which will generate electricity. The turbine will have a series of extractions at different pressures that will be used for preheating air and water in the steam cycle.

The remainder of the steam left after the turbine will be condensed back to water to generate the pressure drop to drive the turbine. A fraction of the steam will condense at the exhaust of the turbine in the form of wet steam, however the majority will be condensed and cooled using an air-cooled condenser. The condensed steam will be returned as feed water in a closed-circuit pipework system to the boiler.

Depending on the requirements of the heat users, either high pressure steam or hot water could be supplied. High pressure steam could be extracted from the turbine and piped directly to the heat users. Alternatively, low pressure steam exiting the turbine could pass through an onsite heat exchanger to heat up water for use in a heat network. The volume of steam extracted would vary depending on the heat load requirements of the heat users. It should be noted that at the time of writing this report, there are no formal agreements in place for the export of heat from the Facility.

4.1.3 Details of Input Waste

Table 1: Expected Facility input waste characteristics

Parameter	Unit	Value
Nominal waste throughput	tpa	429,197

Parameter	Unit	Value
Maximum waste throughput	tpa	495,000
Proposed NCV	MJ/kg	10.25
Proposed GCV	MJ/kg	11.85

4.2 Details of Heat Supply System

Heat is typically supplied from the energy recovery process in the form of steam and / or hot water, depending on the grade of heat required by the end consumers.

The most commonly considered options for recovering heat are discussed below.

1. Heat recovery from the condenser

Wet steam emerges from the steam turbine typically at around 40 °C. This energy can be recovered in the form of low-grade hot water from the condenser depending on the type of cooling implemented.

An ACC will be installed at the Facility. Steam is condensed in a large air-cooled system which rejects the heat in the steam into the air flow, which is rejected to atmosphere. An ACC generates a similar temperature condensate to mechanical draught or hybrid cooling towers. The condensate then returns back to the boiler. Cooling this condensate further by extracting heat for use in a heat network requires additional steam to be extracted from the turbine to heat the condensate prior to being returned to the boiler. This additional steam extraction reduces the power generation from the plant and therefore reduces the plant power efficiency and power revenues.

2. Heat extraction from the steam turbine

Steam extracted from the steam turbine can be used to generate hot water for district heating schemes. District heating schemes typically operate with a flow temperature of 90 to 120 °C and return water temperature of 50 to 80 °C. Steam is preferably extracted from the turbine at low pressure to maximise the power generated from the steam. Extraction steam is passed through a condensing heat exchanger(s), with condensate recovered back into the feedwater system. Hot water is pumped to heat consumers for consumption before being returned to the primary heat exchangers where it is reheated.

Where steam is used for heating hot water, it is normally extracted from a lowest pressure bleeds on the turbine, depending on the heating requirements of the heat consumers.

This source of heat offers the most flexible design for a heat network. The steam bleeds can be sized to provide additional steam above the Facility's parasitic steam loads. However, the size of the heat load needs to be clearly defined to allow the steam bleeds and associated pipework to be adequately sized. The capacity of the bleeds cannot be increased once the turbine has been installed.

3. Heat extraction from the flue gas

The temperature of flue gas exiting the flue gas treatment plant is typically around 140 °C and contains water in vapour form. This can be cooled further using a flue gas condenser to recover the latent heat from the moisture. This heat can be used to produce hot water for district heating in the range 90 to 120 °C. This method of heat extraction does not significantly impact the power generation from the plant.

Condensing the flue gas can be achieved in a flue gas condenser. However, the recovered temperature is typically no more than 80 °C, which restricts the hot water temperature available for the consumer. Additionally, condensing water vapour from the flue gas reduces the flue gas volume and hence increases the concentration of non-condensable pollutants within it. The lower volume of cooler gas containing higher concentration of some pollutants would likely require a different stack height to effect adequate dispersion. The additional cooling of the flue gas results in the frequent production of a visible plume from the chimney and although this is only water vapour it can be misinterpreted as pollution. The water condensed from the flue gas needs to be treated and then discharged under a controlled consent.

The best solution to supply heat for the network under consideration is by extracting steam from the turbine. This method for the supply of heat is considered to be favourable for the following reasons.

1. The heat requirements of the identified consumers (as described in section 5.2) are too high for the temperatures attainable from the turbine exhaust steam.
2. The use of a flue gas condenser would generate a visible plume which would be present for significant periods of the year. This is not desirable as it will significantly add to the visual impact of the Facility and as such has not been included.
3. Extraction of steam from the turbine offers the most flexibility for varying heat quality and capacity to supply variable demands or new future demands.
4. Extraction of steam from the turbine, heat transfer to a hot water circuit and delivery of heat to consumers can be facilitated by well proven and highly efficient technology.

5 Heat Demand Investigation

5.1 Wider Heat Export Opportunities

5.1.1 The National Comprehensive Assessment

'National Comprehensive Assessment of the Potential for Combined Heat and Power and District Heating and Cooling in the UK'[3] (the NCA), dated 16 December 2015, was published by Ricardo AEA Ltd on behalf of the Department of Energy and Climate Change (now part of the Department for Business, Energy and Industrial Strategy). The report was produced to fulfil the requirement (under Directive 2012/27/EU on energy efficiency) on all EU Member States to undertake a National Comprehensive Assessment (NCA) to establish the technical and socially cost-effective potential for high-efficiency cogeneration. The report also sets out information pertaining to heat policy development in the UK. Due to the low resolution of the data, the results of the NCA can be considered as an overview only.

Table 2 details the heat consumption in 2012 and estimated consumption in 2025 by sector for the North East of the UK as extracted from the NCA. Heat consumption is greatest in the industrial and residential sectors. Heat demand from the industrial and residential sectors is above the national average. The estimated heat consumption in 2025 is lower than in 2012, most notably in the residential sector. The energy projections take account of climate change policies where funding has been agreed and where decisions on policy design are sufficiently advanced to allow robust estimates of policy impacts to be made, including measures such as building regulations.

Table 2: Heat consumption in the North East of the UK

Sector	2012 consumption (TWh/annum)	2025 consumption (TWh/annum)
Industry (including agriculture)	11	10
Commercial services	1	1
Public sector	1	1
Residential	13	11
Total	**25**	**22**

Source: National Comprehensive Assessment of the Potential for Combined Heat and Power and District Heating and Cooling in the UK, Ricardo AEA, December 2015

Current and projected space cooling consumption data detailed in Table 3. Given the paucity of available data on energy consumption for cooling, these figures are estimates based on consumption indicators, building types and floor areas; consequently, they should be considered as indicative.

[3]National Comprehensive Assessment of the Potential for Combined Heat and Power and District Heating and Cooling in the UK, Ricardo AEA, December 2015

Table 3: Cooling consumption in the North East of the UK

Sector	2012 consumption (TWh/annum)	2025 consumption (TWh/annum)
Industry (including agriculture)	0	0
Commercial services	0	0
Public sector	0	0
Total	**1**	**0**

Source: National Comprehensive Assessment of the Potential for Combined Heat and Power and District Heating and Cooling in the UK, Ricardo AEA, December 2015

It is assumed that the apparent discrepancy in the figures is due to rounding errors. It is not possible to verify this as access to the underlying data is not available.

5.1.2 UK CHP Development Map

The Department for Business, Energy and Industrial Strategy (BEIS) UK CHP Development Map[4] geographically represents heat demand across various sectors in England, Scotland, Wales and Northern Ireland. A search of heat consumers within 15 km of the Facility was carried out, as shown in Table 4. This is represented as coloured contour areas in Figure 3, with each colour band representing a range of heat demand density values.

The data returned considers the entire regional area into which the search area extends. If a search radius extends marginally into a particular region, the data for the entire region will be included in the results table so there is a possibility that the heat demand can be overestimated.

With the exception of public buildings, the heat map is produced entirely without access to the meter readings or energy bills of individual premises. Therefore, results should be taken as estimates only.

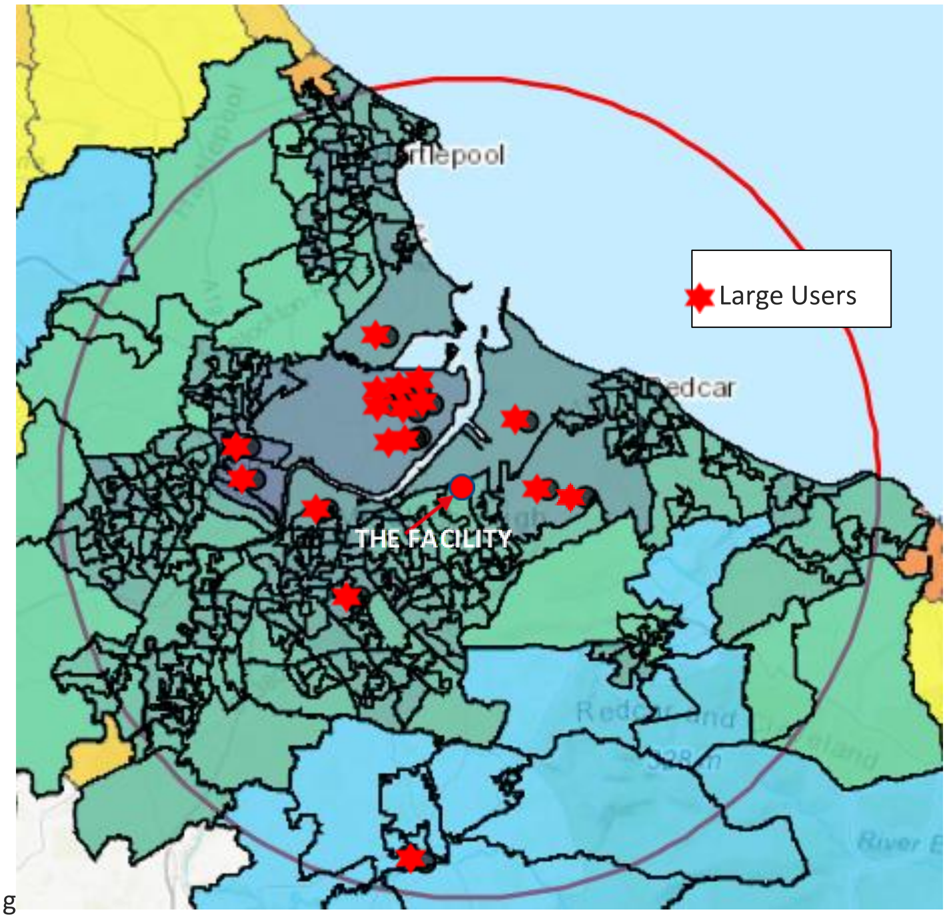
[4] http://chptools.decc.gov.uk/developmentmap/

Table 4: Heat demand within 15 km of the Facility

Sector	Heat demand	
	MWh/a	**% share**
Communications and Transport	4,954	0%
Commercial Offices	126,411	1%
Domestic	2,607,771	22%
Education	74,690	1%
Government Buildings	18,722	0%
Hotels	20,651	0%
Large Industrial	6,356,851	53%
Health	46,039	0%
Other	5,235	0%
Small Industrial	134,258	1%
Prisons	-	0%
Retail	36,166	0%
Sport and Leisure	10,246	0%
Warehouses	4,298	0%
District Heating	2,583,902	21%
Total heat load in area	**12,030,193**	**100%**

Source: UK CHP Development Map

Figure 3: Local heat demand density



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Source: UK CHP Development Map

The heat demand in the area surrounding the Facility is predominantly from the commercial/industrial sectors, and to a lesser extent, the domestic sector. In most cases, existing domestic buildings are unsuitable for inclusion in a heat network as a result of the prohibitive costs of replacing existing heating infrastructure and connecting multiple smaller heat consumers to a network. To secure the most economically viable heat network, Fichtner has attempted to identify consumers that will provide maximum return and carbon saving for the minimum cost. Therefore, the approach to this study has focused on industrial and commercial consumers within the search radius.

Section 5.1.4 identify potential heat users that would provide maximum return and carbon saving.

5.1.3 Large Heat Consumers

Seventeen large heat consumers (point heat demands greater than 5 MW_{th}) were identified within 15km of the Proposed Development using the BEIS UK CHP Development Map[5] tool, as shown as shown in detailed in Table 5 and Figure 3.

[5] http://chptools.decc.gov.uk/developmentmap/

Table 5: Large Heat Consumers

Site	Heat demand (MWh/annum)
Large heat consumer 1	2,675,750
Large heat consumer 2	2,551,929
Large heat consumer 3	1,670,138
Large heat consumer 4	546,827
Large heat consumer 5	471,251
Large heat consumer 6	379,236
Large heat consumer 7	225,499
Large heat consumer 8	103,784
Large heat consumer 9	98,076
Large heat consumer 10	75,926
Large heat consumer 11	49,773
Large heat consumer 12	36,959
Large heat consumer 13	28,589
Large heat consumer 14	27,975
Large heat consumer 15	27,807
Large heat consumer 16	23,284
Large heat consumer 17	21,010

The locations of the large heat consumers identified are at distances that would require a prohibitively costly pipe network to connect. Physical constraints imposed by the local infrastructure and topology have a significant impact on which loads can viably be connected. River and rail crossings are technically challenging and may obstruct the most direct route to the consumer. Connecting most of these large heat users to a heat network from the Facility would require river and rail crossings. The above distances assume river crossings and rail crossings will use existing road bridges. Crossings and associated new infrastructure will increase the cost of the network. Due to the estimated distances and complexity of the connections to these heat consumers, they have been discounted. Nearby Wilton Power station, which is operated by Sembcorp has its own CHP plant therefore it has been discounted.

5.1.4 Visual Assessment

From a review of satellite imagery and aerial photography, potential heat consumers have been identified in the area surrounding the Facility, and are listed in Table 6. The locations of these heat consumers relative to the Facility are shown in Appendix A. Connecting these consumers would not require and rail, river or major road crossing and there would be no disruption to residential areas.

A list of potential heat consumers identified within 15 km of the Facility, applying engineering judgement to screen out unfavourable routes, is provided in Table 6. The list includes industrial estates surrounding the Facility. It includes units for low-grade industrial uses, retail, manufacturing and warehousing. It is likely that more heat users would be identified at the detailed design phase. There is a potential heat demand of approximately 45,557 MWh/year. At this stage, these heat consumers have not been contacted. Until the Environmental Permit has been granted and detailed design has been undertaken the heat export conditions are not known, making it difficult for potential heat consumers to determine whether they would be interested in importing heat. When detailed design has been undertaken and an Environmental Permit for the Facility granted, potential heat consumers will be contacted. Each potential consumer's heat consumption has been estimated using the method outlined in Section 5.2.

Table 6: Potential heat users – visual assessment

Map Reference	Business Name/Description	Category	Estimated heat load at point of use (MWh/a)
1	Marshbrook Motors	B1 - Small offices/Light industry	243
2	Master Radiators	B1 - Small offices/Light industry	201
3	Truck Tech North East Ltd	B1 - Small offices/Light industry	99
4	Vantech Northern Ltd	B1 - Small offices/Light industry	120
5	Glass Technology	B1 - Small offices/Light industry	244
6	Bolckow Industrial Estate	B1 - Small offices/Light industry	499
7	Wood street	B1 - Small offices/Light industry	60
8	Lee Road	B1 - Small offices/Light industry	155
9	Cargo Pallets Ltd	B1 - Small offices/Light industry	300
10	Holden Close	B1 - Small offices/Light industry	764
11	South Tees Freight Park	B1 - Small offices/Light industry	3,240
12	John Boyle Rd	B1 - Small offices/Light industry	428
13	Puddlers Rd	B1 - Small offices/Light industry	2,753
14	Nelson Street Industrial Estate	B1 - Small offices/Light industry	2,065
15	South Tees Imperial Food Park	B1 - Small offices/Light industry	566
16	Old Station Rd	B1 - Small offices/Light industry	572
17	Skippers Lane Ind Est	B1 - Small offices/Light industry	14,921
18	Cargo Fleet	B1 - Small offices/Light industry	18,327
	Total		**45,557**

5.2 Estimated Overall Heat Load

Broad assumptions have been made regarding the estimated heat demand from existing potential heat consumers. Heat demands have been calculated based on benchmark figures from the Chartered Institution of Building Services Engineers (CIBSE) Guide F (Energy Efficiency in Buildings). This document provides good practice benchmark figures based on energy performance of existing buildings. In the CIBSE Guide, loads are expressed in terms of kWh per square metre of floor space per year of fossil fuel use (natural gas is typically assumed). Based on estimates of floor areas and an assessment of the development type, it is possible to estimate annual energy usage. Converting natural gas use to actual heat loads (which can be provided by a hot water distribution system) requires an assumption of gas-fired boiler efficiency. An efficiency of 80 % is assumed, based on industry norms.

Based on this benchmark, the users identified in section 5.1.4 have a total annual heat consumption of 45,557 MWh/a, with a required heat export of 47,787 MWh/a when diversified and accounting for pipe losses. It should be noted that for large heating systems all individual peak loads do not necessarily occur at the same time. Therefore, the network peak demand is not the sum of the individual peak loads due to the diversity of demand.

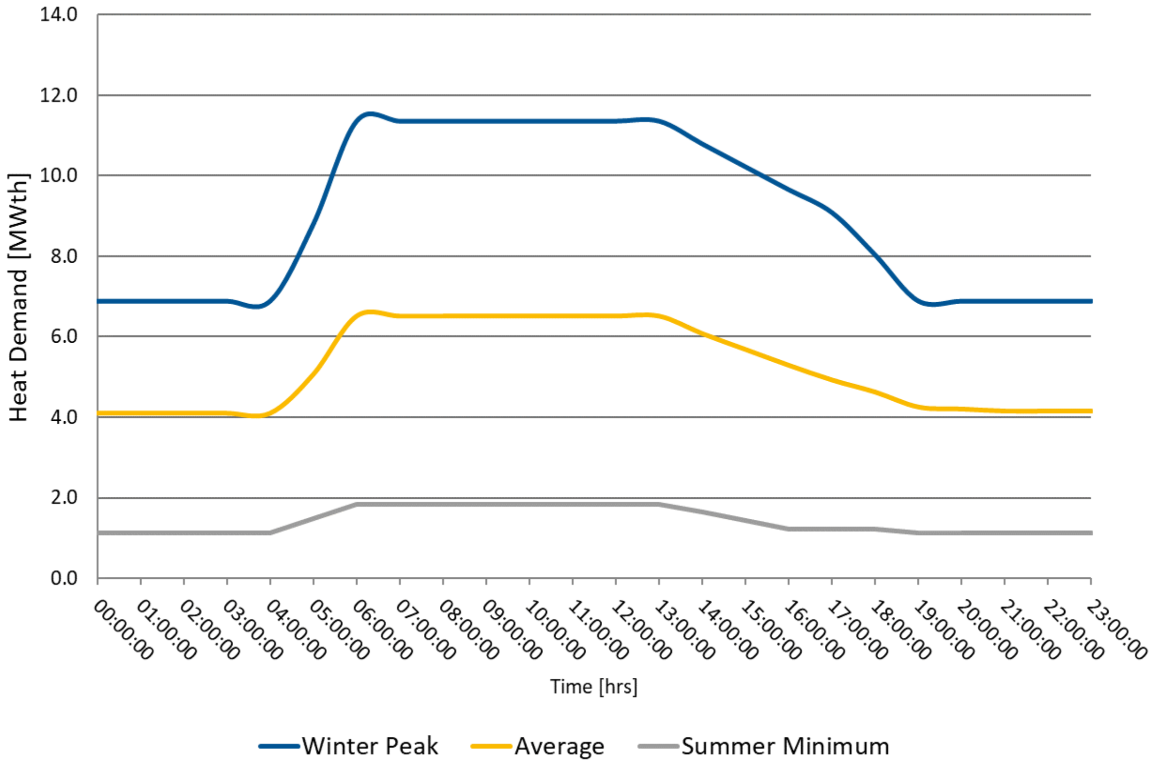
6 Heat Network Technical Solution

6.1 Heat Network Profile

A generic heat demand profile has been developed to model the seasonal and diurnal variation in heat demand for the proposed heat network, by integrating the estimated annual heat demands (in MWh). This has allowed the annual average and peak heat demands (in MW) to be calculated.

The heat network profile for the proposed heat network is shown in Figure 4 and illustrates the variation in heat demand during a typical day in different seasons. The profile represents heat demand at the point of use and therefore does not include network heat losses.

Figure 4: Heat network profile



Daily and seasonal variation in heat demand is typical for heat networks serving industrial, commercial and office consumer types, which form the basis of the proposed heat network. Increasing the number and type of consumers connected to a network diversifies heat demand and helps to reduce the impact of the peak demand of any individual consumer, since it is less likely that peak demands will coincide.

The total annual heat export, and average and peak instantaneous network values are projected in Table 7.

Table 7: Proposed heat network demand

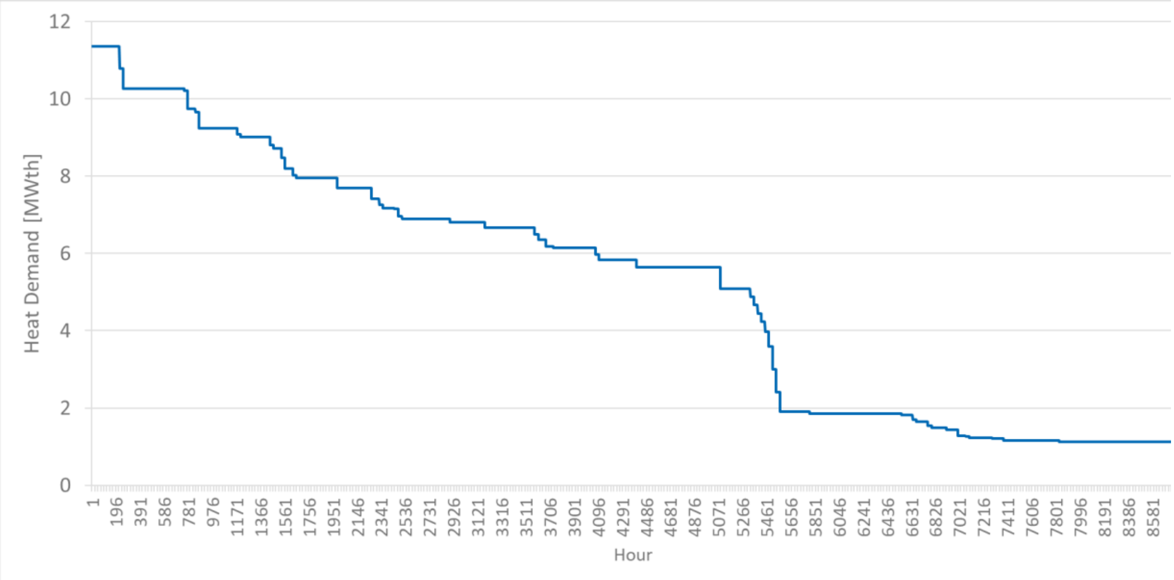
Annual Heat Load (MWh/a)		Average heat demand (MWth)		Peak heat demand (MWth)		
At point of use	Accounting for pipe losses	At point of use	Accounting for pipe losses	Peak winter value	After applying diversity factor	diversified with pipe losses
45,557	47,787	5.20	5.46	11.55	11.30	11.55

6.1.1 Heat Load Duration Curve

The heat load duration curve presented in Figure 5 displays the instantaneous heat demand for the proposed heat network, arranged in order of decreasing magnitude, across the year.

Since detailed heat demand data is not available at this stage, the heat load duration curve has been developed on the basis of instantaneous heat demand at each hour of the day for each month. This demand data does not heat losses.

Figure 5: Heat load duration curve



6.2 Heat Network Design

As a conventional heat network, heat distribution between the Facility and the identified heat consumers located in nearby industrial estates would likely use buried pipework. Pre-insulated steel pipes would be used to supply pressurised hot water to the customer, and to return cooler water. Where pipes are small, two pipes may be integrated within a single insulated sleeve. For larger heat demands, large bore pipes would be installed as a single insulated run. Pipe technology is well proven and can provide a heat distribution system with a 30 year plus design life. Additional pipe work can be added retrospectively, and it is reasonably straightforward to add branches to serve new developments.

Modern heat-insulated piping technology enables hot water to be transferred large distances without significant losses. Where the topography creates challenges, heat exchangers and additional pumping systems can be installed to create pressure breaks, enabling the network to be extended.

Heat delivery arriving at a heat consumer's premises usually terminates using a secondary heat exchanger. The heat exchanger is typically arranged to supply heat to a tertiary heating circuit upstream of any boiler plant. The water in the tertiary circuit is boosted to the temperature required to satisfy the heating needs of the building.

Water is pumped continuously around the system. Pumps are operated with 100% standby capacity to maintain heat in the event of a pump fault. Pumps are likely to utilise variable speed drives to minimise energy usage.

The following conservative design criteria relate to a typical hot water network utilising conventional heat extraction (as detailed in section 4.2) and have been used to size the heat transmission pipe diameters. Where possible, the flow temperature will be reduced to minimise heat losses and this will be subject to the requirements of the heat consumers. Flow and return temperatures presented in Table 8 have been selected on the basis of the likely requirements of identified consumers.

Table 8: District heating network design criteria

Parameter	Value
Water supply temperature to consumer	95°C
Water return temperature from consumer	55°C
Distance between flow and return pipes	150 mm
Soil temperature	10°C
Depth of soil covering	600 mm

Using the above design criteria and allowing for the estimated heat demand for the preferred network, the primary hot water transmission pipe size has been calculated as DN200, reducing along the length of the pipe network to DN20 at the consumer located farthest from the Facility. This is an indicative figure and will be subject to heat demand verification and subsequent network design. Assuming the difference between the flow and return temperatures (deltaT) remains constant, it will be possible to reduce the flow temperature in the future in line with the CIBSE Code of Practice without impacting the pipe size and thereby reduce system energy losses.

6.3 Back-up Heat Sources

The Facility has been designed to achieve an availability of 93.0 % (i.e. 8,147 operational hours per year). During periods of routine maintenance or unplanned outages the Facility will not be operating, however the heat consumers will still require heat. There is therefore a need, somewhere within the heat distribution system, to provide a back-up source of heat to meet the needs of the heat consumers.

At the heat network scale under consideration, the standby plant will likely comprise oil- or gas-fired hot water heaters (boilers) with a separate dedicated chimney stack. Back-up boilers are typically designed to ensure that the peak heat export capacity can be met but also provide sufficient turndown to supply smaller summer loads with reasonable efficiency.

However, in the case that a majority of heat consumers were to retrofit connections to storage and distribution warehousing, it is possible that existing heating/cooling infrastructure could be retained as back up. The back-up strategy would need to be developed as part of the detailed design phase. Subject to detailed heat demand modelling once heat consumers are known with more certainty, opportunities for installing thermal stores may also be considered to lessen reliance on the back-up plant by storing excess heat generated during off peak periods for use during times of peak heat demand.

Indicative costs of installing and operating back-up plant have been included in the economic assessment in Section 8.3.

6.4 Considerations for Pipe Route

At the present time, no definitive fixed route has been established for the connections from the Facility to the various potential users since no specific agreements have been made. However, an indicative pipe route is presented in Appendix A.

Planning permission, easements and Highways Licenses would need to be obtained for access, construction, and maintenance of the pipeline infrastructure. There is a significant financial implication for obtaining easements, and these would only be progressed once planning permission and an EP have been granted for the Facility and heat supply agreements put in place. Traffic management requirements would need to be agreed prior to being able to obtain the necessary Highways Licenses granting permission to install the pipework. The projected timetable for the development of the heat mains is detailed in Section 6.5.

Discussion with the various potential heat consumers will need to be entered into which, if successful, would lead into the production of a heat supply agreement and designs for the pipework. A full economic analysis will need to be undertaken, considering the costs associated with pipe installation and lost electricity revenue in order to determine a suitable heat price per unit. However, without an EP being granted for the Facility, any firm commitment to a supply of heat is difficult to achieve.

6.5 Implementation Timescale

The table below gives an indicative timetable for the programme for the construction of the Facility and heat network. The start of the construction of the heat system is dependent on the viability of the system and the location of the heat consumers. For example, planning and gaining consent for installation of the pipework off the site would take a significant amount of time due to the potential impact on local traffic management. Until a core of heat consumers have been identified and contracted to take heat, pipeline installation will not commence.

Table 9: Implementation programme

Description	Schedule
Obtain Permitting for the Facility	Day 1
Completion of Negotiation for Heat Supply Contracts	6 months
Start of Construction of plant	9 months
Submit planning application for heat mains	18 months
Start of commissioning of the Facility	30 months
Take Over of the Facility	36 months
Completion of Construction on Heat System	52 months
Testing & Commissioning of Heat Network	53 months
Start-up of the Heat Supply	54 months

7 Energy Efficiency Calculations

7.1 Heat and Power Export

The Z ratio, which is the ratio of reduction in power export for a given increase in heat export, can be used to calculate the effect of variations in heat export on the electrical output of the Facility. A value of 6.85 was obtained following the approach set out in CHPQA Guidance Note 28[6], assuming steam extraction at a pressure of 1.9 bar(a), which is considered sufficient to meet the requirements of the potential heat consumers identified for the Facility. The heat and power export has been modelled across a range of load cases and the results are presented in Table 10.

Table 10: Heat and power export

Load case	Heat export at turbine (MW_{th})	Gross power generated (MWe)	Net power exported (MW_e)	Z ratio
1. No heat export	0.0	48.2	43.6	N/A
2. Proposed network heat load (see Section 6.1)	5.46	47.4	42.9	6.85
3. Maximum heat export capacity	12.00	46.4	41.9	6.85

The results indicate that for the heat consumers identified in Section 5.1.4 and 5.2, load case 2 corresponding to an average heat export of 5.46 MW_{th} will result in a net power export of 42.9 MW_e.

7.2 CHPQA Quality Index

CHPQA is an energy efficiency best practice programme initiative by the UK Government. CHPQA aims to monitor, assess and improve the quality of CHP in the UK. In order to prove that a plant is a 'Good Quality' CHP plant, a QI of at least 105 must be achieved at the design, specification, tendering and approval stages. Under normal operating conditions (i.e. when the scheme is operational) the QI threshold drops to 100. The QI for CHP schemes is a function of their heat efficiency and power efficiency according to the following formula:

$$QI = X\eta_{power} + Y\eta_{heat}$$

where: η_{power} = power efficiency; and

η_{heat} = heat efficiency.

The power efficiency within the formula is calculated using the gross electrical output and is based on the gross calorific value of the input fuel. The heat efficiency is also based on the gross calorific value of the input fuel. The coefficients X and Y are defined by CHPQA based on the total gross electrical capacity of the scheme and the fuel / technology type used.

[6] CHPQA Guidance Note 28, 2007

In December 2018, the Government released a revised CHPQA Standard Issue 7. The document sets out revisions to the design and implementation of the CHPQA scheme. These revisions are intended to ensure schemes which receive Government support are supplying significant quantities of heat and delivering intended energy savings. The following X and Y coefficients apply to the Facility:

- X value = 220; and
- Y value = 120.

The QI and efficiency values (based on a gross calorific value of 11.85 MJ/kg) have been calculated in accordance with CHPQA methodology for various load cases and the results are presented in Table 11.

Table 11: QI and efficiency calculations

Load case	Gross power efficiency (%)	Heat efficiency (%)	Overall efficiency (%)	CHPQA QI
1. No heat export	27.77	0.00	27.77	61.1
2. Proposed network heat load (see Section 6.1)	27.31	3.15	30.45	63.9
3. Maximum heat export capacity	26.75	6.92	33.67	67.2

The results indicate that the Facility will not achieve a QI score in excess of the 'Good Quality' CHP threshold (QI of 105 at the design stage) for the average heat load exported to the proposed heat network. The highly onerous efficiency criteria set out in the latest CHPQA guidance, most notably the underpinning requirement to achieve an overall efficiency (NCV basis) of at least 70%, means that none of the load cases considered will enable heat export from the Facility to be considered Good Quality.

For reference, assuming the same Z ratio as set out in the preceding section, an average heat export of 87 MW_{th} would be required for a heat network to achieve Good Quality status. It is clear that the design proposed for heat recovery is not capable of supplying this quantity of heat at the assumed conditions required by the local network.

8 Heat Network Economic Assessment

8.1 Fiscal Support

The following fiscal incentives are available to energy generation projects and impact the feasibility of delivering a district heating network.

8.1.1 Capacity Market for electricity supplied by the Facility

Under the Capacity Market, subsidies are paid to electricity generators (and large electricity consumers who can offer demand-side response) to ensure long-term energy security for the UK. Capacity Agreements are awarded in a competitive auction and new plants (such as the Facility) are eligible for contracts lasting up to 15 years. Based on the eligibility criteria of the mechanism, the Facility will be eligible for Capacity Market support. Since support is based on electrical generation capacity (which would reduce when operating in CHP mode), these payments will act to disincentivise heat export and have therefore not been included in the economic assessment.

8.1.2 Renewable Heat Incentive

The Renewable Heat Incentive (RHI) was created by the Government to promote the deployment of heat generated from renewable sources. However, no funding announcements have been published for the RHI post March 2022. Therefore, it is unlikely the Facility will receive incentives under the RHI. In addition, to be eligible, the plant in question must not receive any other support or subsidy from public funds including any support received under the Capacity Market. Therefore, if the Facility qualifies for support under the Capacity Market mechanism, it will not be eligible for the RHI.

8.1.3 Contracts for Difference

Contracts for Difference (CfD) has replaced the Renewables Obligation (RO) as the mechanism by which the Government supports low carbon power generation. CfD de-risks investing in low carbon generation projects by guaranteeing a fixed price (the Strike Price) for electricity over a 15-year period. In the second CfD allocation round (executed on 11 September 2017) no funding was allocated for Energy from Waste plants, with or without CHP, on the basis that these are now considered established technologies. The third allocation[7] round was executed in September 2019 with contracts awarded to eligible less established technologies only[8].

The Government has confirmed that it plans to hold the next allocation round in 2021. The Government has also announced that it intends to hold further auctions every two years on a rolling basis. Under the current regulations, CfD delivery years subject to auction must end on 31st March 2026. BEIS has released a consultation[9] on changes ahead of the fourth allocation round for CfD. This consultation proposes that the CfD scheme be extended to cover delivery years until 31st March 2030 and confirms that allocation round 4 will include auctions for both established (Pot 1) and less established (Pot 2) technologies, with energy from waste with CHP included in Pot 1. The

[7] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/832924/Contracts_for_Difference_CfD_Allocation_Round_3_Results.pdf

[8] https://www.gov.uk/government/collections/contracts-for-difference-cfd-third-allocation-round

[9] https://www.gov.uk/government/consultations/contracts-for-difference-cfd-proposed-amendments-to-the-scheme-2020

justification is that the strike price at auction for Pot 1 will likely be below or near the wholesale price for electricity, meaning these projects would effectively be zero subsidy. In this case, the CfD might not provide financial support, but it would provide long term security on the price to be achieved, which can be useful in securing financing. On this basis, the Facility would not receive support under the CfD mechanism but could secure long term security on the electricity price.

8.1.4 Heat Network Investment Project funding

The Heat Network Investment Project (HNIP) aims to deliver carbon savings and create a self-sustaining heat network market through the provision of subsidies, in the form of grants and loans, for heat network projects. £320 million has been made available to fund the HNIP between 2019 and 2022. Following a pilot scheme, which ran from October 2016 to March 2017, the Department for Business, Energy and Industrial Strategy (BEIS) has confirmed that funding will be available for both public and private sector applicants, and that there will be no constraints on scheme size. The 2020 Budget confirms £96 million for the final year of the HNIP, which ends in March 2022.

The HNIP may be a source of funding that would improve the economic viability of the heat network. The level of funding that the Facility could achieve under this program would depend on the final size of the network and commercial arrangements.

Relatively modest grant funding, to assist local authorities in heat network project development, is also available through the Heat Networks Delivery Unit (HNDU), although this could not be received by the Facility directly and would not serve to support project delivery.

8.1.5 Green Heat Networks Scheme

After HNIP ends in March 2022, the government will invest a further £270 million in a new Green Heat Networks Scheme (GHNS), enabling new and existing heat networks to be low carbon and connect to waste heat that would otherwise be released into the atmosphere.

Following discussions with BEIS, the UK District Energy Association (ukDEA) can advise the following regarding this new GHNS and difference to HNIP:

1. GHNS is to enable new and existing networks to be low carbon and connect to waste heat. It is not for the construction of heat networks in themselves as the HNIP fund is. To be clear this new GHNS fund is very much about driving the transition towards a low carbon source of heat for planned and existing networks and not specifically about delivering large scale heat networks as HNIP is.
2. GHNS is a capital grant fund and not a split loan and grant as HNIP is.
3. The GHNS fund will be available from 2022 to 2025.
4. The GHNF will fund up to, but not including, 50 per-cent of a project's total combined commercialisation and capex costs.

   GHNS is aimed at waste heat as a heat source and would not apply to steam extractions from turbine. Therefore, the Facility will not be eligible for the GHNS in its current design.

8.2 Technical feasibility

Step 3 of the CBA methodology requires identification of existing and proposed heat loads which are technically feasible to supply. The draft Article 14 guidance states that the following factors should be accounted for when determining the technical feasibility of a scheme, pertaining to a type 14.5(a) installation.

1. The compatibility of the heat source(s) and load(s) in terms of temperature and load profiles

The CHP scheme has been developed on the basis of delivering heat at typical district heating conditions (refer to Section 6.2). It is reasonable to assume that identified potential heat consumers would be able to utilise hot water at the design conditions. Consumer requirements (in terms of hot water temperature and load profiles) will need to be verified in any subsequent design process prior to the implementation of a heat network. Therefore, the heat source and heat load are considered to be compatible.

2. Whether thermal stores or other techniques can be used to match heat source(s) and load(s) which will otherwise have incompatible load profiles

Conventional thermal stores or back-up boilers (as detailed in Section 6.3) will likely be included in the CHP scheme to ensure continuity of supply. The specific arrangement will be selected when there is greater certainty with regards heat loads.

3. Whether there is enough demand for heat to allow high-efficiency cogeneration

High-efficiency cogeneration is cogeneration which achieves at least 10% savings in primary energy usage compared to the separate generation of heat and power. Primary energy saving (PES) is calculated in the following section.

8.2.1 Primary energy savings

To be considered high-efficiency cogeneration, the scheme must achieve at least 10% savings in primary energy usage compared to the separate generation of heat and power. PES have been calculated in accordance with European Commission Delegated Regulation (EU) 2015/2402 of 12 October 2015 Annex II part (b), using the following assumptions.

1. Annual nominal throughput capacity of 429,197 tonnes per annum based on an NCV of 10.25 MJ/kg.
2. Nominal gross electrical output (expected capacity in fully condensing mode) of 48.2MW$_e$.
3. Parasitic load is 4.63 MW$_e$.
4. Z ratio of 6.85.
5. Efficiency reference values for the separate production of heat and electricity have been taken as 80% and 25% respectively as defined in Commission Delegated Regulation (EU) 2015/2402 of 12 October 2015[10].

When operating in fully condensing mode (i.e. without heat export) the Facility will achieve a PES of 22.12 %. This is in excess of the technical feasibility threshold defined in the draft Article 14 guidance. The inclusion of heat export at the design case level anticipated for the proposed heat network increases PES to 23.56 %. On this basis, the Facility will qualify as a high-efficiency cogeneration operation when operating in CHP mode.

8.3 Results of CBA

A CBA has been carried out on the selected heat load, in accordance with section 3 of the draft Article 14 guidance. The CBA uses an Excel template, '*Environment Agency Article 14 CBA Template.xlsx*' provided by the EA, with inputs updated to correspond with the specifics of this Heat Plan.

The CBA model considers:

[10] http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32015R2402

1. the revenue streams (heat sales);
2. the costs streams for the heat supply infrastructure (construction and operational, including back-up plant); and
3. the lost electricity sales revenue, over the lifetime of the scheme.

The following assumptions have been made:

1. The DH scheme will commence operation in 2025.
2. The heat export infrastructure required to export heat from the Facility to the consumers identified is estimated to have a capital cost of approximately £9.92 million, split over a two-year construction programme.
3. The heat station will cost approximately £1.72million, split over a two-year construction programme.
4. Back-up boilers will be provided to meet the peak heat demand, at a cost of approximately £2.30 million.
5. Operational costs have been estimated based on similar sized projects.
6. Heat sales revenue will be £40 / MWh, current price and index linked for inflation in CBA.
7. Electricity sales revenue will be £57 / MWh, current price and index linked for inflation in CBA.
8. Standby boiler fuel costs will be £25 / MWh, current price and index linked for inflation in CBA.
9. Standby boiler(s) will supply 3.5% of annual heat exported.

The results of the CBA indicate that both the nominal project internal rate of return and net present value (before financing and tax) over 30 years are 9.6 % and -£5.02 million respectively. Unattractive returns are a result of large network pipe lengths resulting in higher capital expenditure, combined with a relatively low identified heat demand. Therefore, it is considered that the proposed heat network does not yield an economically viable scheme in its current configuration. Model inputs and key outputs are presented in Appendix C.

9 CHP-Ready BAT Assessment

9.1 CHP-Ready BAT Assessment

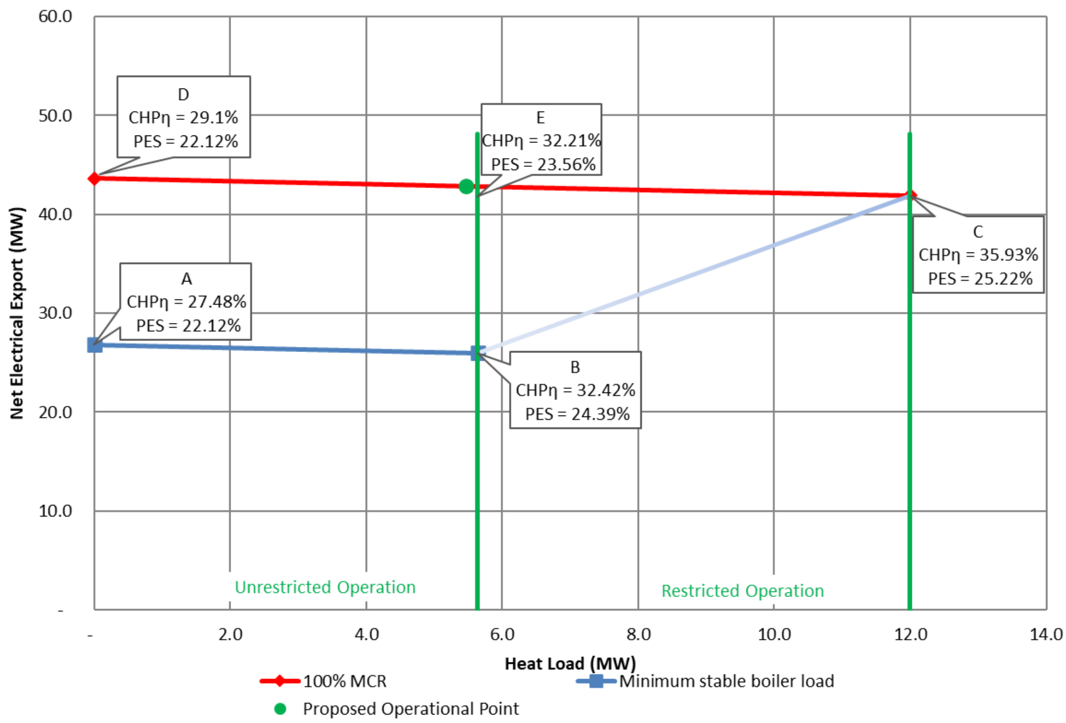
This report includes a CHP-Ready Assessment which considers the requirements of the EA's CHP-Ready Guidance. The completed CHP-Ready Assessment form is provided in Appendix D.

The 'CHP envelope' as outlined under requirement 2 of the CHP-Ready guidance, which identifies the potential operational range of a new plant where it could be technically feasible to operate electrical power generation with heat generation, is provided in Figure 6.

The points defining the CHP envelope are as follows.

- A: minimum stable load (with no heat extraction).
- B: minimum stable load (with maximum heat extraction).
- Line A to B: minimum electrical power output for any given heat load (corresponds to the minimum stable plant load).
- C: 100% load (with maximum heat extraction).
- D: 100% load (with no heat extraction).
- Line D to C: maximum electrical power output for any given heat load (corresponds to 100% plant load).
- E: proposed operational point of the Facility, based on the proposed heat network.
- Unrestricted operation: if a selected heat load is located in this region, the Facility will have the ability to operate at any load between minimum stable plant load and 100% plant load whilst maintaining the selected heat load.
- Restricted operation: if a selected heat load is located in this region, the Facility will not have the ability to operate over its full operational range without a reduction in heat load.

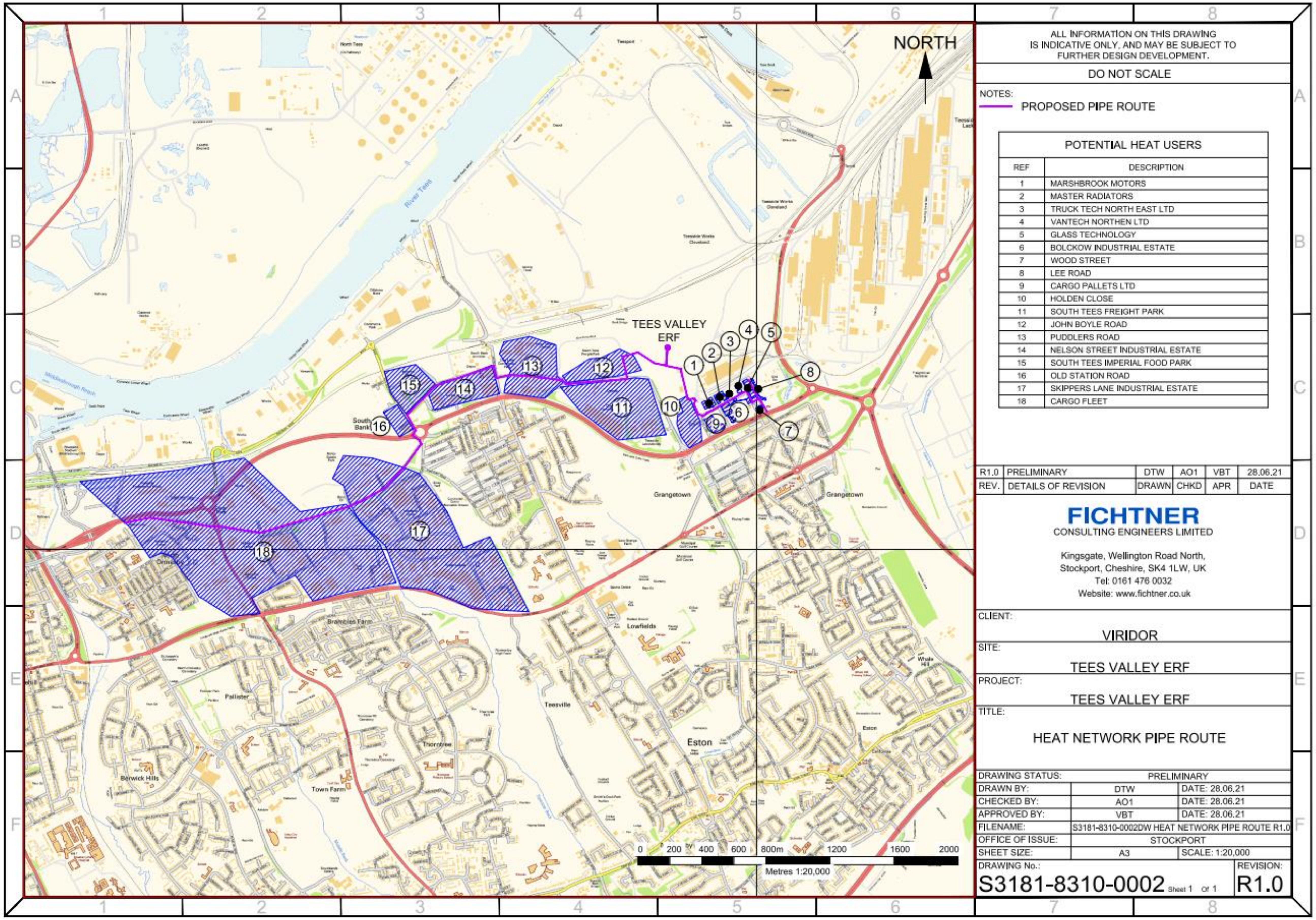
Figure 6: Graphical representation of CHP envelope for proposed heat network



The proposed operational point (point E) represents the annual average heat demand exported to the proposed heat network detailed in section 5 and 6.1. It considers the heat losses and pressure drop in the pipe network and therefore corresponds to the annual average heat demand predicted at the Facility site boundary. The operational range for the Facility will ultimately be subject to the required hot water flow temperature and final steam turbine selection, which are subject to detailed design.

Appendices

A Pipe route and heat users


NORTH
TEES VALLEY ERF
South Bank
Grangetown
Eston
ALL INFORMATION ON THIS DRAWING IS INDICATIVE ONLY, AND MAY BE SUBJECT TO FURTHER DESIGN DEVELOPMENT.
DO NOT SCALE
NOTES:
PROPOSED PIPE ROUTE
POTENTIAL HEAT USERS
REF DESCRIPTION
1 MARSHBROOK MOTORS
2 MASTER RADIATORS
3 TRUCK TECH NORTH EAST LTD
4 VANTECH NORTHEN LTD
5 GLASS TECHNOLOGY
6 BOLCKOW INDUSTRIAL ESTATE
7 WOOD STREET
8 LEE ROAD
9 CARGO PALLETS LTD
10 HOLDEN CLOSE
11 SOUTH TEES FREIGHT PARK
12 JOHN BOYLE ROAD
13 PUDDLERS ROAD
14 NELSON STREET INDUSTRIAL ESTATE
15 SOUTH TEES IMPERIAL FOOD PARK
16 OLD STATION ROAD
17 SKIPPERS LANE INDUSTRIAL ESTATE
18 CARGO FLEET
R1.0 PRELIMINARY DTW AO1 VBT 28.06.21
REV. DETAILS OF REVISION DRAWN CHKD APR DATE
FICHTNER
CONSULTING ENGINEERS LIMITED
Kingsgate, Wellington Road North, Stockport, Cheshire, SK4 1LW, UK
Tel: 0161 476 0032
Website: www.fichtner.co.uk
CLIENT: VIRIDOR
SITE: TEES VALLEY ERF
PROJECT: TEES VALLEY ERF
TITLE: HEAT NETWORK PIPE ROUTE
DRAWING STATUS: PRELIMINARY
DRAWN BY: DTW DATE: 28.06.21
CHECKED BY: AO1 DATE: 28.06.21
APPROVED BY: VBT DATE: 28.06.21
FILENAME: S3181-8310-0002DW HEAT NETWORK PIPE ROUTE R1.0
OFFICE OF ISSUE: STOCKPORT
SHEET SIZE: A3 SCALE: 1:20,000
DRAWING No.: S3181-8310-0002 Sheet 1 Of 1
REVISION: R1.0
0 200 400 600 800m 1200 1600 2000
Metres 1:20,000

B Site Location and Layout Drawings

Please refer to Appendix A of EP Application Supporting Information

C CBA Inputs and Key Outputs

INPUTS — Version Jan 2015

Scenario Choice (dropdown box): 1 — Power generator (Heat Source) same fuel amount

Key	
2	Participant to define
2	Regulatory prescribed
2	Calculated
2	Prescribed - but possibility to change if make a case

Technical solution features

Heat carrying medium (hot water, steam or other) (dropdown box)	Hot water
Total length of supply pipework (kms)	5.66
Peak heat demand from Heat User(s) (MWth)	11.55
Annual quantity of heat supplied from the Heat Source(s) to Heat User(s) (MWh)	*Lines 49 & 79*

DCF Model Parameters

Discount rate (pre-tax pre-financing) (%) - 17% suggested rate	17%
Project lifespan (yrs)	30
Exceptional shorter lifespan (yrs)	0

Cost and revenue streams

Construction costs and build up of operating costs and revenues during construction phase

	% operating costs and revenues during construction phase	Heat Supply Infrastructure - used in Scenarios 1, 2, 3 and 5	Heat Station - used in Scenarios 1, 2 and 3	Standby boilers (only if needed for Scenarios 1, 2 and 3)	Industrial CHP - used in Scenario 4 *
Project asset lifespan (yrs)		30	30	30	
Exceptional reason for shorter lifespan of Heat Supply Infrastructure, Standby Boiler and/ or Heat Station (yrs)					
Construction length before system operational and at steady state (yrs)	2				
Number of years to build		2	2	2	0
	% (ONLY IF APPLICABLE)	£m	£m	£m	£m
Year 1 costs (£m) and build up of operating costs and revenues (%)	0%	4.95926014	0.859002325	1.15052154	
Year 2 costs (£m) and build up of operating costs and revenues (%)	0%	4.95926014	0.859002325	1.15052154	
Year 3 costs (£m) and build up of operating costs and revenues (%)					
Year 4 costs (£m) and build up of operating costs and revenues (%)					
Year 5 costs (£m) and build up of operating costs and revenues (%)					

Non-power related operations

OPEX for full steady state Heat Supply Infrastructure on price basis of first year of operations (partial or steady state) (£m)	0.1
OPEX for full steady state Heat Station on price basis of first year of operations (partial or steady state) (£m)	0.1
OPEX for full steady state Standby Boilers on price basis of first year of operations (partial or steady state) (£m)	0.1
OPEX for full steady state Industrial CHP on price basis of first year of operations (partial or steady state) (£m) *	
Additional equivalent OPEX to pay for a major Industrial CHP overall spread over the life of the asset (£m) on price basis of first year of operations (partial or steady state) (£m) *	
Other 1 - Participant to define (£m)	

Other 2 - Participant to define (£m)	
Total non-power related operations	**0.2**
Annual inflation for all non-power related OPEX from first year of operations (full or partial) (%)	2.0%

Unit Energy Prices, Energy Balance, Fuel Related Operational costs and Revenue Stream

	Scenario used	1 Power generator (Heat Source) same fuel amount	2 Power generator (Heat Source) same electrical output	3 Industrial installation (Heat Source) - use waste heat	4 Industrial installation (Heat Source) - CHP set to thermal input	5 District heating (Heat User)
Heat sale price (£/ MWh) at first year of operations (partial or full)	40.00	40.00				
Annual quantity of heat supplied from the Heat Source(s) to Heat User(s) at steady state (MWh)	47,787	47,787				
Equivalent heat sales if first year of operations is steady state (£ m)	1.9					
Heat sale price inflation from first year of operations (full or partial) (% per year)	2.0%	2.0%				
Percentage of heat supplied by Standby Boiler (if relevant)	4%	4%				
'Lost' electricity sale price (£/ MWh) at first year of operations	57.00	57.00				
Z-ratio (commonly in the range 3.5 - 8.5)	6.85	6.85				
Power generation lost at steady state (MWh)	6,732	6,732				
Equivalent 'lost' revenue from power generation if first year of operations is steady state (£ m)	0.38					
Electricity sale price inflation from first year of operations (full or partial) (% per year)	2.0%	2.0%				
Industrial CHP electricity sale price (£/ MWh) at first year of operations (full or partial)	0.00					
Industrial CHP electrical generation in steady state (MWh)	0					
Equivalent revenue from power generation if first year of operations is steady state (£ m)	0.00					
Industrial CHP electricity price inflation from first year of operations (full or partial) (% per year)	0.0%					
Fuel price for larger power generator/ CHP at first year of operations (full or partial) (£ / MWh)	0.00					
Z-ratio (commonly in the range 3.5 - 8.5)	0					
Power efficiency in cogeneration mode (%)	0					
Additional fuel required per year for larger power generator / CHP in steady state (MWh)	0		#DIV/0!			
Equivalent additional fuel costs if first year of operations is steady state (£ m)	0.00					
Fuel price inflation from first year of operations (full or partial) (% per year)	0.0%					
Fuel price for Standby Boiler at first year of operations (£ / MWh)	25.00	25.00				
Boiler efficiency of Standby Boiler (%)	80%	80%	80%	80%		
Additional fuel required per year for Standby Boiler in steady state (MWh)	2,091	2,091	-	-		
Equivalent additional fuel costs if first year of operations is steady state (£m)	0.05					
Fuel price inflation for Standby Boiler from first year of operations (full or partial) (% per year)	2.00%	2.0%				

Heat purchase price (£/ MWh) at first year of operations (partial or full)	0.00		
Annual quantity of heat supplied from the Heat Source(s) to Heat User(s) at steady state (MWh)	0		
Equivalent cost of heat purchased if first year of operations is steady state (£ m)	0.0		
Heat purchase price inflation from first year of operations (full or partial) (% per year)	0.0%		
Fuel price (£ / MWh) at first year of operations (partial or full)	0.00		
Boiler efficiency of district heating plant	0%		80%
Fuel avoided per year in steady state (MWh)	0		-
Equivalent fuel savings if first year of operations is steady state (£m)	0.0		
Fuel price inflation from first year of operations (full or partial) (% per year)	0.0%		4.0%
Fiscal benefits (£m) in first year of operations assuming it is at steady state **	0.00	0.00	
Fiscal benefits inflation rate from first year of opeations (full or partial) (%) **	0.0%		

* In the case of Industrial CHP a separate model template is available for typical indicative CAPEX, non-power related OPEX, additional equivalent OPEX to pay for a major overall, MWh of electricity generated in the steady state and the additional fuel required.

** Operator only needs to enter a value for fiscal benefits (£m) and the annual fiscal benefit inflation rate (%) if the NPV without fiscal benefits is negative at the specified discount rate

OUTPUTS

Nominal Project IRR (before financing and tax) over 32 years	9.6%
Nominal NPV (before financing and tax) (£m) over 32 years	-5.02

D CHP-R Assessment Form

#	Description	Units	Notes / Instructions
Requirement 1: Plant, Plant location and Potential heat loads			
1.1	Plant name		Tees Valley Energy Recovery Facility
1.2	Plant description		The main activities associated with the Facility will be the combustion of incoming waste to raise steam and the generation of electricity in a steam turbine/generator. The Facility includes two waste incineration lines, waste reception hall, main thermal treatment process, turbine hall, on-site facilities for the treatment or storage of residues and waste water, flue gas treatment, stack, boilers, devices and systems for controlling operation of the waste incineration plant and recording and monitoring conditions. In addition to the main elements described, the Facility will also include weighbridges, water, auxiliary fuel and air supply systems, site fencing and security barriers, external hardstanding areas for vehicle manoeuvring, internal access roads and car parking, transformers, grid connection compound, firewater storage tanks, offices, workshop, stores and staff welfare facilities. The Facility has been designed to export power to the National Grid. The Facility will generate approximately 48.2MWe of electricity in full condensing mode. The Facility will have a parasitic load of 4.63 MWe. Therefore, the maximum export capacity of the Facility is 43.6 MWe. In addition to generating power, the Facility has been designed to be capable of exporting up to 12 MW_{th} heat to local heat users. However, it is assumed that maximum heat export capacity is 11.55 MW_{th}, which is suitable for the identified district heating network. The maximum heat capacity will be subject to the requirements of the heat consumers and confirmed during detailed design stage. At the time of writing this report, there are no formal agreements in place for the export of heat from the Facility. The power exported may fluctuate as fuel quality fluctuates, and if heat is exported from the Facility to local heat users in the future. The Facility has been designed to thermally treat waste with a range of net calorific values (NCV's) with a Net Calorific Value (NCV) of 7 MJ/kg to 14 MJ/kg. The nominal capacity of the Facility is 52.6 tonnes per

#	Description	Units	Notes / Instructions
			hour of fuel with an NCV of 10.25 MJ/kg. The expected operational availability is 8,147 hours per annum (~93%), which is regarded as typical for an EfW plant in the UK. Therefore, the nominal capacity for the installation is 429,197 tonnes per annum. Assuming the lowest the realistic annual average NCV is 8.5 MJ/kg, then the Facility will have a maximum capacity of up to approximately 500,322 tonnes per annum (again assuming 8,147 hours availability).
1.3	Plant location (Postcode / Grid Ref)		The site is located on land within the South Tees Development Corporation (STDC) area, which comprises 4,500 acres (1,800 hectares) of land that forms part of the STDC's Regeneration Master Plan. The site occupies a 25-acre (10 hectare) site situated at the southwestern corner of the STDC area, within the Grangetown Prairie Zone. The site lies 1.2km south of the River Tees and approximately 4miles to the north east of Middlesbrough Town centre. The Facility will be located at an approximate national grid reference NZ 54436 21340.
1.4	Factors influencing selection of plant location		Refer to Section 3 of EIA, submitted with planning application.
1.5	Operation of plant		
a)	Proposed operational plant load	%	100
b)	Thermal input at proposed operational plant load	MW	150.00
c)	Net electrical output at proposed operational plant load	MW	43.65
d)	Net electrical efficiency at proposed operational plant load	%	29.10%
e)	Maximum plant load	%	100
f)	Thermal input at maximum plant load	MW	150.00
g)	Net electrical output at maximum plant load	MW	43.65
h)	Net electrical efficiency at maximum plant load	%	29.10%
i)	minimum stable plant load	%	65%
j)	Thermal input at minimum stable plant load	MW	97.50
k)	Net electrical output at minimum stable plant load	MW	25.97
l)	Net electrical efficiency at minimum stable plant load	%	26.64%

#	Description	Units	Notes / Instructions
1.6	Identified potential heat loads		
			Details of the identified heat loads are in Sections 5 and 6.1. Following consumer screening and accounting for network heat losses and consumer diversity, potential consumers were identified with an average heat load of 5.46 $MW_{th.}$ and a peak load of 12 MW_{th} for the proposed heat network. The estimated heat use of the identified network is 47,787 MWh/year.
1.7	Selected heat load(s)		
a)	Category (e.g. industrial / district heating)		District heating
b)	Maximum heat load extraction required	MW	The average and diversified peak heat demand of the proposed heat network has been calculated to be 5.46 MW_{th} and 12 MW_{th} respectively.
1.8	Export and return requirements of heat load		
a)	Description of heat load extraction		Network to supply hot water at typical district heating temperatures (approximately 95°C) via turbine steam extractions at approximately 1.9 bar(a).
b)	Description of heat load profile		The heat load profile is variable due to mixed use developments (primarily industrial and commercial). A detailed heat load profile can be found in section 6.1 of the Heat Plan. The consumer heat load and profile is subject to verification.
c)	Export pressure	bar a	10
d)	Export temperature	°C	95
e)	Export flow	t/h	195.25 (nominal case)
f)	Return pressure	bar a	3
g)	Return temperature	°C	55
h)	Return flow	t/h	195.25 (nominal case)
Requirement 2: Identification of CHP Envelope			
2.0	Comparative efficiency of a standalone boiler for supplying the heat load	% LHV	80% - updated in accordance with CHPQA Stakeholder Engagement Document, April 2016, Table 1.
2.1	Heat extraction at 100% plant load		

#	Description	Units	Notes / Instructions
a)	Maximum heat load extraction at 100% plant load	MW	12.00
b)	Maximum heat extraction export flow at 100% plant load	t/h	Assuming steam extraction at 1.91 bar(a), export flow rate would be: 6.876 t/hr
c)	CHP mode net electrical output at 100% plant load	MW	41.90
d)	CHP mode net electrical efficiency at 100% plant load	%	27.93%
e)	CHP mode net CHP efficiency at 100% plant load	%	35.93%
f)	Reduction in primary energy usage for CHP mode at 100% plant load	%	25.22%
2.2	Heat extraction at minimum stable plant load		
a)	Maximum heat load extraction at minimum stable plant load	MW	5.64
b)	Maximum heat extraction export flow at minimum stable plant load	t/h	Assuming steam extraction at 1.91 bar(a), export flow rate would be: 3.23 t/h
c)	CHP mode net electrical output at minimum stable plant load	MW	25.97
d)	CHP mode net electrical efficiency at minimum stable plant load	%	26.64%
e)	CHP mode net CHP efficiency at minimum stable plant load	%	32.42%
f)	Reduction in primary energy usage for CHP mode at minimum stable plant load	%	24.39%
2.3	Can the plant supply the selected identified potential heat load (i.e.is the identified potential heat load within the 'CHP envelope')?		Yes, but not deemed 'Good Quality' CHP as detailed in section 7 of the Heat Plan.
Requirement 3: Operation of the Plant with the Selected Identified Heat Load			
3.1	Proposed operation of plant with CHP		
a)	CHP mode net electrical output at proposed operational plant load	MW	42.85
b)	CHP mode net electrical efficiency at proposed operational plant load	%	28.57%

#	Description	Units	Notes / Instructions
c)	CHP mode net CHP efficiency at proposed operational plant load	%	32.21%
d)	Reduction in net electrical output for CHP mode at proposed operational plant load	MW	0.80
e)	Reduction in net electrical efficiency for CHP mode at proposed operational plant load	%	0.53%
f)	Reduction in primary energy usage for CHP mode at proposed operational plant load	%	23.56%
g)	Z ratio		6.85
Requirement 4: Technical provisions and space requirements			
4.1	Description of likely suitable extraction points		Steam for the district heating system could be supplied via a controlled steam flow extraction from low pressure turbine bleed at approximately 1.91 bar(a). Full details are provided in section 4.2 of the Heat Plan.
4.2	Description of potential options which could be incorporated in the plant, should a CHP opportunity be realised outside the 'CHP envelope'		The CHP opportunity lies within the CHP envelope.
4.3	Description of how the future costs and burdens associated with supplying the identified heat load / potential CHP opportunity have been minimised through the implementation of an appropriate CHP-R design		If the scheme were to be implemented, space will be allocated for the CHP equipment within or in the area adjacent to the turbine hall to avoid the cost of building a dedicated heat station at a later date. The turbine design will be selected to maximise electrical efficiency while allowing for the option of heat export to be implemented in the future. This is in line with the EA CHP-Ready Guidance which states that the initial electrical efficiency of a CHP-R plant (before any opportunities for the supply of heat are realised) should be no less than that of the equivalent non-CHP-R plant.
4.4	Provision of site layout of the plant, indicating available space which could be made available for CHP-R		Detailed design of the Facility has not been undertaken at this stage. However, space will be left available within or in the area adjacent to the turbine hall for heat export infrastructure. Please see the site layout in Appendix B. The heat network will (likely) include steam extraction piping, control and shutoff valves, heat exchangers, district heating supply and return lines, district heating circulation pumps, condensate return piping (to the condensate tank), control and instrumentation / electrical connections, an

#	Description	Units	Notes / Instructions
			expansion tank for pressurisation of the district heating pipe network and heat metering. If necessary, a back-up boiler will be located at a suitable location within the installation boundary for ease of connection to the primary hot water circuit.
Requirement 5: Integration of CHP and carbon capture			
5.1	Is the plant required to be CCR?		No
5.2	Export and return requirements identified for carbon capture		
	100% plant load		
a)	Heat load extraction for carbon capture at 100% plant load	MW	N/A
b)	Description of heat export (e.g. steam / hot water)		N/A
c)	Export pressure	bar a	N/A
d)	Export temperature	°C	N/A
e)	Export flow	t/h	N/A
f)	Return pressure	bar a	N/A
g)	Return temperature	°C	N/A
h)	Return flow	t/h	N/A
i)	Likely suitable extraction points		N/A
	Minimum stable plant load		
j)	Heat load extraction for carbon capture at minimum stable plant load	MW	N/A
k)	Description of heat export (e.g. steam / hot water)		N/A
l)	Export pressure	bar a	N/A
m)	Export temperature	°C	N/A
n)	Export flow	t/h	N/A
o)	Return pressure	bar a	N/A
p)	Return temperature	°C	N/A
q)	Return flow	t/h	N/A
r)	Likely suitable extraction points		N/A
5.3	Operation of plant with carbon capture (without CHP)		

#	Description	Units	Notes / Instructions
a)	Maximum plant load with carbon capture	%	N/A
b)	Carbon capture mode thermal input at maximum plant load	MW	N/A
c)	Carbon capture mode net electrical output at maximum plant load	MW	N/A
d)	Carbon capture mode net electrical efficiency at maximum plant load	%	N/A
e)	Minimum stable plant load with CCS	%	N/A
f)	Carbon capture mode CCS thermal input at minimum stable plant load	MW	N/A
g)	Carbon capture mode net electrical output at minimum stable plant load	MW	N/A
h)	Carbon capture mode net electrical efficiency at minimum stable plant load	%	N/A
5.4	Heat extraction for CHP at 100% plant load with carbon capture		
a)	Maximum heat load extraction at 100% plant load with carbon capture [H]	MW	N/A
b)	Maximum heat extraction export flow at 100% plant load with carbon capture	t/h	N/A
c)	Carbon capture and CHP mode net electrical output at 100% plant load	MW	N/A
d)	Carbon capture and CHP mode net electrical efficiency at 100% plant load	%	N/A
e)	Carbon capture and CHP mode net CHP efficiency at 100% plant load	%	N/A
f)	Reduction in primary energy usage for carbon capture and CHP mode at 100% plant load	%	N/A
5.5	Heat extraction at minimum stable plant load with carbon capture		
a)	Maximum heat load extraction at minimum stable plant load with carbon capture	MW	N/A

#	Description	Units	Notes / Instructions
b)	Maximum heat extraction export flow at minimum stable plant load with carbon capture	t/h	N/A
c)	Carbon capture and CHP mode net electrical output at minimum stable plant load	MW	N/A
d)	Carbon capture and CHP mode net electrical efficiency at minimum stable plant load	%	N/A
e)	Carbon capture and CHP mode net CHP efficiency at minimum stable plant load	%	N/A
f)	reduction in primary energy usage for carbon capture and CHP mode at minimum stable plant load	%	N/A
5.6	Can the plant with carbon capture supply the selected identified potential heat load (i.e. is the identified potential heat load within the 'CHP and carbon capture envelope')?		N/A
5.7	Description of potential options which could be incorporated in the plant for useful integration of any realised CHP system and carbon capture system		N/A
Requirement 6: Economics of CHP-R			
6.1	Economic assessment of CHP-R		In order to assess the economic feasibility of the CHP scheme (as required under Article 14 of the Energy Efficiency Directive) a cost benefit assessment has been carried out in accordance with the draft Article 14 guidance. The results of the CBA indicate an internal rate of return of 9.6 % and a net present value of -£5.02 million. The proposed heat network will not yield an economically viable scheme in its current configuration. The economic feasibility of the scheme will be reassessed in the future when there is a better understanding of heat demands and considering any subsidies that support the export of heat.

#	Description	Units	Notes / Instructions
BAT assessment			
	Is the new plant a CHP plant at the outset (i.e. are there economically viable CHP opportunities at the outset)?		No
	If not, is the new plant a CHP-R plant at the outset?		Yes
	Once the new plant is CHP-R, is it BAT?		Yes

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