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FORD SITE ENERGY STUDY
FINANCIAL ANALYSIS

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FINANCIAL ANALYSIS

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Contents

No table of contents entries found.

TABLE OF FIGURES

1. INTRODUCTION

The City of St. Paul is in a process of preparing for the redevelopment the former Ford production facility into a sustainable urban neighborhood which aims to be a show case for an attractive and livable community developed around a district energy system.

Building on the Energy Study work for the Ford Site Redevelopment to date, this memorandum responds to a revised Activity 1.7 outlining the findings of an analysis of the financial viability of the derived energy supply concepts.

Ramboll has worked on the following analysis:

- Based on **development Scenario 5,** estimations of the likely build out phasing of the site, and the likely energy demand and its duration throughout the year.

- Analysis of three (3) technical concepts for financial viability (as agreed at the TAG meeting on 2015-29-01):

  - **Concept 0:** Business as usual Concept, **BAU** (Grid electricity, natural gas individual heating, and cooling with air conditioning)
  - **Concept 1:** District energy Concept, **DHC** (ATES based heat pump/chiller energy production, Solar Thermal, River free cooling, thermal storage (day-to-day) and gas boiler as back-up)
  - **Concept 2:** Individual generation Concept, **IND** (Solar PV on roof tops, central (ground source) heat pumps for heating and chillers for cooling, hot water storage (day-to-day))

The district energy concept has changed since the original outline of concepts for the financial analysis ref: CSP-39-001-Activity1.7-Financial Analysis Brief regarding assumptions. It now includes Aquifer Thermal Energy Storage (ATES) instead of the river source heat pump scheme. This change was implemented as a result of poor technical feasibility on the heat pumps as the temperature of the Mississippi drops to below freezing point during approx. 4 months of the year.

The analysis methodology and process is briefly outlined below.

To add the most value to the study, the Technical Advisory Group (TAG) subcommittee has provided input to the financial analysis, especially regarding pricing of installations, pipes, and the expected build out of the site.

An initial outline of the proposed analysis and its basic assumptions and base information was presented to the TAG subcommittee prior to a conference call on May 5, 2015. Its purpose was to clarify analysis setup, align expectations, and engage the TAG subcommittee to provide the input needed. Ref.: CSP-39-001-Activity1.7-Financial Analysis Brief regarding assumptions
Now the document will serve as an appendix on the financial analysis, for the main report.

In order to compare the three concepts, all assumptions must be aligned and coordinated across the chosen concepts.

Concept 0 - BAU was chosen as the reference scenario, since it represents the business as usual with regards to energy supply. The weighted average heating and cooling price of the BAU concept will be calculated based on all investments and costs of installing and supplying energy.

Estimating the average price per MMBtu (MWh) energy that a customer will pay in a business as usual (BAU) scenario, it is possible to compare the three concepts. This is done by using the reference heating and cooling price from the BAU concept as the reference prices in concept 1 and 2. In other words, the costumers are expected to pay the same price per MMBtu (MWh) energy in all three concepts, determined by the BAU scenario. Thus, the economic analysis will be able to identify which project is viable. Furthermore, if concept 1 and 2 are less viable from a financial view point than concept 0, potential investment gab can be identified.

2. SITE BUILD OUT AND CONNECTIONS

As noted in Section 1, all financial analysis is based on the Concept 5 from the Phase 1 Summary Report[1].

Based on input from a subcommittee of the TAG, the following phasing of the build out of the site has been assumed.

Table 1 Start development year

Area	Year
Green	0
Yellow	3
Blue	6
Red	10

Each area is assumed to be completed within 5 years from the start development year, and buildings fully occupied within 5 years of completion.

Figure 1 Site Development

[1] http://www.stpaul.gov/DocumentCenter/Home/View/3162

3. ENERGY DEMAND

The client and their advisors have chosen to proceed with Activity 1.7 using scenario 5 with an increased residential density as the baseline for building stock area and type distribution.

An overview of the building type areas included in scenario 5 is listed in Table 2 below:

Table 2 - Scenario 5 Building Type Areas

Unit	Total Heated/Cooled Floor Area (ft2)	Total Heated/Cooled Floor Area (m2)
Apartment/Condo (Low Density - 28 units/acre)	534,000	49,610
Apartment/Condo (Medium Density - 45 units/acre)	1,296,000	120,402
Apartment/Condo (High Density - 80 units/acre)	570,000	52,955
Civic	50,000	4,645
Retail/Mixed use	375,000	34,839
Official/Institutional	194,000	18,023

The estimated Site Energy Utilization Intensity (EUI) for different building types have been provided according to climate zone 6A (St. Paul) and the SB 2030 code, and are outlined below in table 3. The SB 2020 energy demands used for this assessment are shown below highlighted in blue. To account for any uncertainty regarding which category to apply (small, medium or large in Table 3), median values of the three categories are used.

Table 3 - Site Energy Utilization Intensity (EUI)

kBtu/ft²/yr		~ Current Minnesota Energy Code					~ Expected future energy code in Minnesota					
		ASHRAE 90.1-2004 [1]			2015 IECC / ASHRAE 90.1-2013 [2]		SB 2030					
	Prototype Floor Area (sf)	National Average Site EUI	**Climate Zone 6 Average Site EUI**	Factor between National and Climate Zone	National Average Site EUI	**Climate Zone 6 Average Site EUI**	2003 Baseline	2010 60% below	2015 70% below	2020 [6] 80% below	2025 90% below	2030 100% below
Small office	5.502	42,4	**53,7**	1,267	29,4	**37,2**	157,5	63,0	47,3	32,0	15,8	-
Medium office	53.628	49,5	**62,2**	1,256	34,1	**42,8**	155,0	62,0	46,5	30,0	15,5	-
Large office	498.588	84,5	**99,7**	1,179	70,8	**83,5**	150,0	60,0	45,0	30,0	15,0	-
Stand-alone retail	24.692	79,5	**107,2**	1,348	45,9	**61,9**	147,5	59,0	44,3	29,5	14,8	-
Strip mall retail	22.500	83,7	**118,3**	1,414	55,1	**77,9**	150,0	60,0	45,0	30,0	15,0	-
Supermarket [3]	n/a	179,0	**208,0**	1,162	*110,8*	**128,7**	297,5	119,0	89,3	59,5	29,8	-
Primary school	73.959	80,1	**100,1**	1,250	54,2	**67,8**	175,0	70,0	52,5	34,0	17,5	-
Secondary school	210.887	72,9	**98,4**	1,348	41,7	**56,2**	150,0	60,0	45,0	29,3	15,0	-
Hospital	241.501	170,5	**179,9**	1,055	123,7	**130,5**	197,5	79,0	59,3	79,3	19,8	-
Outpatient health care	40.946	157,4	**161,5**	1,026	115,8	**118,8**	130,0	52,0	39,0	58,7	13,0	-
Full-service restaurant	5.502	471,2	**570,2**	1,210	372,5	**450,8**	225,0	90,0	67,5	48,0	22,5	-
Quick-service restaurant	2.501	653,6	**781,9**	1,196	576,4	**689,6**	245,0	98,0	73,5	52,7	24,5	-
Small hotel	43.202	73,3	**87,4**	1,192	60,0	**71,5**	125,0	50,0	37,5	42,0	12,5	-
Large hotel	122.120	123,5	**151,8**	1,230	89,0	**109,4**	157,5	63,0	47,3	44,0	15,8	-
Warehouse	52.045	25,5	**35,3**	1,381	17,1	**23,6**	105,0	42,0	31,5	20,0	10,5	-
Mid-rise apartment	33.741	52,1	**68,0**	1,304	43,9	**57,3**	205,0	82,0	61,5	38,0	20,5	-
High-rise apartment [4]	84.360	55,3	**72,1**	1,304	46,9	**61,2**	220,0	88,0	66,0	39,5	22,0	-

Using these figures, a total energy demand for each building type has been calculated. The total demands are summarized below in Table 4.

Table 4 - Scenario 5 Total Energy Demands

Unit	Total Heated/Cooled Floor Area (ft2)	Total Demand (MMBtu/yr)	Total demand (MWh/yr)
Apartment/Condo (Low Density - 28 units/acre)	534,000	21,894	6,416
Apartment/Condo (Medium Density - 45 units/acre)	1,296,000	53,136	15,573
Apartment/Condo (High Density - 80 units/acre)	570,000	25,080	7,350
Civic	50,000	1,500	440
Retail/Mixed use	375,000	11,156	3,270
Official/Institutional	194,000	5,981	1,753

Based on Ramboll's experience, as well as input from the University of Minnesota, an energy distribution between heating, cooling, and other has been established. The distribution varies between building types and is summarized in Table 5 below.

Table 5 - Scenario 5 % Energy Distribution

Building type	Total Heated/Cooled Floor Area (ft2)	Total Demand (MMBtu/yr)	Energy Distribution Heating/Cooling/Other
Apartment/Condo (Low Density - 28 units/acre)	534,000	21,894	40%/20%/40%
Apartment/Condo (Medium Density - 45 units/acre)	1,296,000	53,136	40%/20%/40%
Apartment/Condo (High Density - 80 units/acre)	570,000	25,080	40%/20%/40%
Civic	50,000	1,500	30%/30%/40%
Retail/Mixed use	375,000	11,156	30%/30%/40%
Official/Institutional	194,000	5,981	30%/30%/40%

Based on the distribution of energy, annual heating and cooling demands for scenario 5 can be summarised as per table 6:

Table 6 - Scenario 5 Annual Heating and Cooling Demands

Annual Total Heat demand	Annual Total Cooling demand
47,503 MMBtu/yr	25,616 MMBtu/yr
13,922 MWh/yr	7,507 MWh/yr

In order to calculate the peak building heating and cooling load we have estimated[2] the number of equivalent full load hours (eqFLH) that the new energy plant will need to provide annually. These assumptions are detailed in table 7 below.

[2] Qualified estimate based on Rambolls experience and TAG input

Table 7 - Scenario 5 Full Load Hours for Heating and Cooling Plant

Unit	Total Demand (MMBtu/yr)	% Energy Distribution Heat/Cooling/Other	Equivalent Full load hours per year Heat/Cooling
Apartment/Condo (Low Density - 28 units/acre)	21,894	40%/20%/40%	1800/1200
Apartment/Condo (Medium Density - 45 units/acre)	53,136	40%/20%/40%	1800/1200
Apartment/Condo (High Density - 80 units/acre)	25,080	40%/20%/40%	1800/1200
Civic	1,500	30%/30%/40%	1800/1500
Retail/Mixed use	11,156	30%/30%/40%	1800/1500
Official/Institutional	5,981	30%/30%/40%	1800/1500

The estimated peak heating and cooling load for scenario 5 are summarised in table 8, by totalling the individual peak loads of all individual building units.

Table 8 - Scenario 5 Peak Heating and Cooling loads

Peak Heat load	Peak Cooling load
26.390 MMBtu/hr	20.414 MMBtu/hr
7.73 MW	5.98 MW

The capacity will be lower in the DHC concept (concept 1) due to the diversity that must be factored in. The concept of diversity will be further elaborated on in chapter 2.2.3.

3.1 Further Assumptions

In order to obtain realistic building footprint for each of the 38 building units, the scenario 5 map from the *Phase 1 summary report* has been integrated into a GIS platform.

Same-type Buildings are assumed to have an equal number of floors so that there is proportionality between footprint area and the actual unit square footage.

Average site EUI's apply according to SB 2030 (year 2020). 80% of the cooling demand is assumed to be outdoor temperature dependent, compared to 60% of the total heat demand because of the low energy class of new buildings.

Household electricity is not included in the comparison under the assumption that it will be constant across all concepts.

In each Concept, every building will have a hot water storage tank, size depending on buildings purpose. However the capital expenditure connected to the tanks is not included in the analysis because of constant cost in all 3 concepts.

Where local assumptions regarding CAPEX and OPEX have not been available, a paper from the Danish Energy Agency, "Technology Data for Energy Plants, Individual Heating Plants and

Energy", October 2013, has been used instead. An index of 0.80 will be used as the difference between the DKK and USD prices.

In the individual scenarios no reserve capacity is assumed. In the DHC scenario an assumption of redundancy corresponding to N+1 is applied.

The underground sand tunnels on the Ford site were initially assessed with the purpose of serving as thermal storages. However, integrating these into the preliminary analyses is not possible as this would have required extensive on-site investigation which lies outside the scope of this study. .

4. ENERGY CONCEPT

The three concept designs outlined in the current chapter are based on previous knowledge attained in two review memos of December 2014, prepared by Ramboll in collaboration with Krifcon.

1. "*Energy Technologies and System Report*" and
2. "*Best Practices in Building Design*"

4.1 Concept 0: Business As Usual - Individual Energy Production per Building

This is a "Business As Usual" (BAU) case where individual heating and cooling is assumed in each building unit.

4.1.1 Energy Production

Each unit has its own individual heating and cooling production (excluding electricity, which is supplied from the grid).

The chosen technology may differ depending on the building type in question.

- **Small residential unit**: Natural gas boiler (with a Hot Water Tank (HWT)) for heating **and** AC unit for cooling
- **Medium/Large residential unit**: A central natural gas boiler with local distribution for heating **and** a central cooling plant with local distribution
- **Official/Institutional**: A central Natural gas boiler for heating **and** a central cooling plant with local distribution

Table 9 Concept 0 Specifications

Individual Concept	Heating	Cooling	Electricity
Plant type	Natural gas boiler Individual or Common	AC unit Individual or Common	Grid
Plant size, MW	Depending on Building type and size	Depending on Building type and size	
Plant efficiency, %	94% (HHV)	400% (COP = 4)	
Equivalent Full Load Hours	1800	Retail, office, civic: 1500 Apartments: 1200	

4.1.2 Gas network

A natural gas network is established throughout the new development area.
Gas network assumptions provided by Xcel Energy. Figure 2 illustrates the natural gas network connections throughout the area. See also Appendix 8.1.

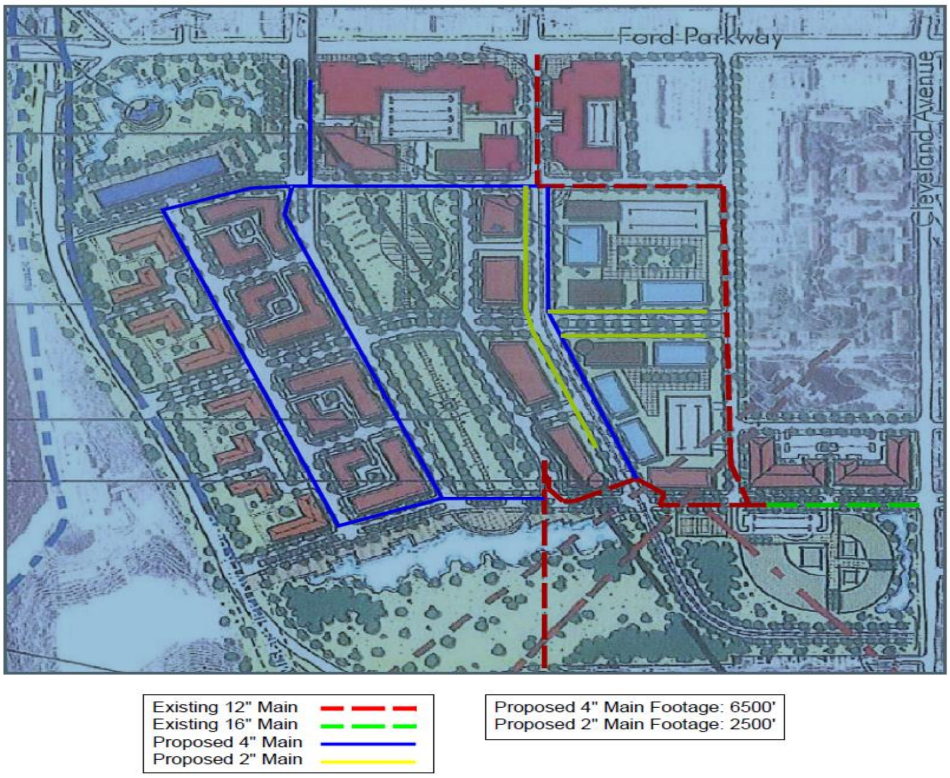


Figure 2 Natural gas network

4.2 Concept 1: District Energy – Centralized Energy Production

Concept 1 is based on energy supply to the site via a District Heating & Cooling (DHC) network.

4.2.1 Energy production

In this concept both heating and cooling will be produced in a central energy center and then distributed via a buried pipe network with individual connections to each building unit.

Ramboll proposes that a groundwater thermal energy storage or aquifer (ATES) storage be applied as the central nerve of the energy center. The use of aquifer storage is possible in most regions but does require some preliminary investigations and testing to establish the suitability and capacity of the soil.

Ground water reservoirs are utilized as seasonal storage to:

1. Supply low grade heat as a source for heat production to the district heating network via high efficient industrial heat pumps.
2. Supply low temperature water into the district cooling network either as free cooling or pre cooling (pre cooling as first step before entering chillers in the energy center).

Other components in the DHC system are:

- The Mississippi river used as a heat sink for the chillers
- Solar thermal installed on the adjacent 4-acre, concrete-sealed area for increased Renewable Energy Supply (RES)
- Simultaneous heat and cooling production through a high efficient combined heat pump/chiller aggregate
- Dedicated chiller units
- Dedicated heat pump units
- Short term energy storage for day-to-day balancing of supply/demand offset.

Table 10 and Table 11 presents the production units divided into prioritized groups based on marginal production cost for heat and cooling production, respectively.

Table 10 Heat production

Base load units	Intermediate load units	Peak and reserve load units
1. Flat plate solar thermal **2. Combined heat pump/chiller unit** **3. Dedicated heat pumps**	4. Flat plate solar thermal (Boost to increase HP efficiency) 5. Short term storage	6. Natural gas boiler*

*In order to insure reliable heat production as well as high flexibility in peak operation a gas boiler is installed.

Heat Pump (HP) heat sources:

- ATES with temperatures up to 77°F (25°C)
- Return water from DC network (source capacity in the combined aggregate and chilled water used to satisfy coinciding cooling demand)
- Solar boost - when solar is not suitable for primary production due to low irradiancy the low temperature heat can be used to boost ground source heated water in order to achieve increased COP in the dedicated heat pumps.

Table 11 Cooling production

Base load units	Intermediate load units	Peak and reserve load units
1. Free cooling (ATES) **2. Combined heat pump/chiller unit** **3. Dedicated chiller units**	4. Pre cooling (ATES) 5. Free cooling (River) 6. Short term storage	7. Dedicated chiller unit (N + 1)

Chiller heat sinks:

- River
- ATES (for yearly balancing if necessary)

The DHC system principle is outlined in Figure 3.

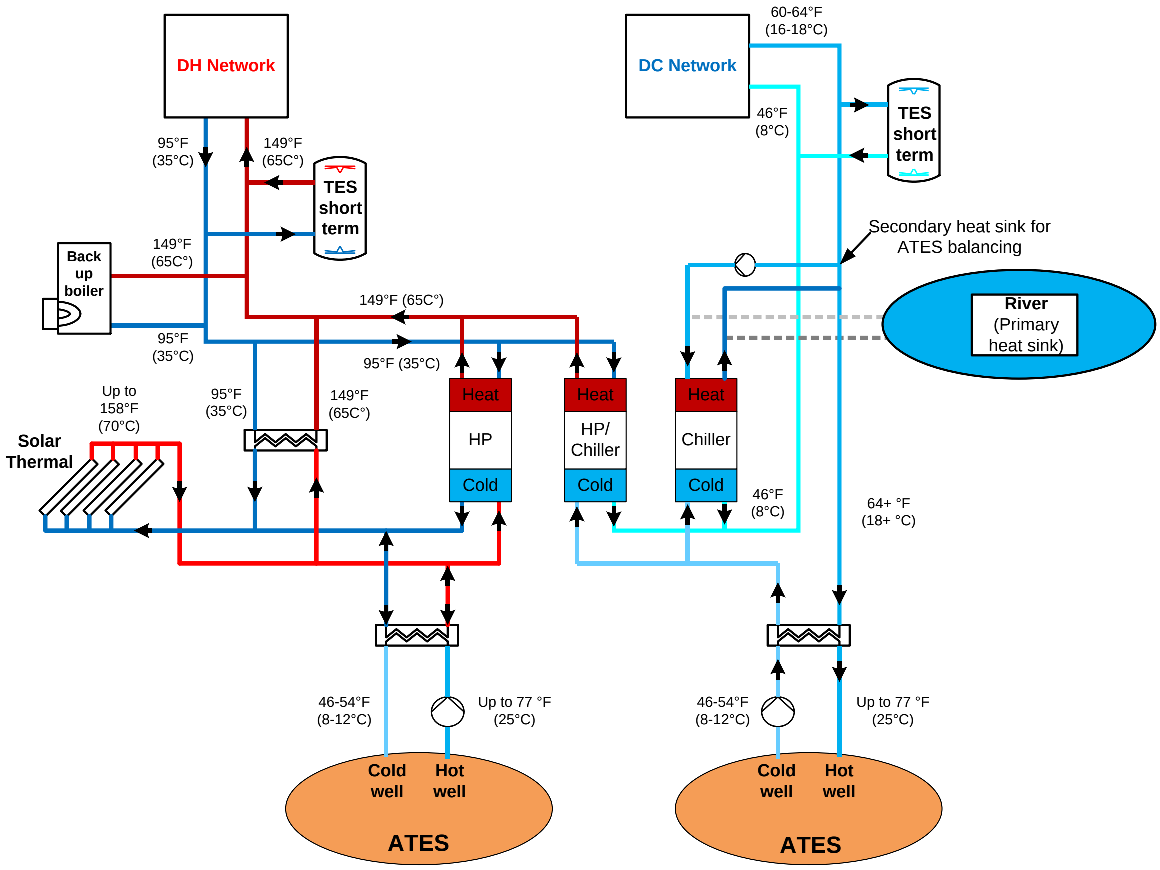


Figure 3 Concept 3 with integrated heating and cooling production + thermal storage

4.2.2 ATES in principle

In order to utilize heat pumps (HP's) as a base load unit in the DH system, a stable low grade heat source must be readily available. ATES provides this.

Water up to 77°F (25°C) is drawn from the "hot" aquifer through a hot well and sourced to the HP's. While useful high grade heat is discharged in the DH network on the hot side of the HP, the source water on the cold side of the HP is cooled down, heat is extracted in the process, and returned to the ATES in a cold aquifer where it is preserved at a stable temperature of 46–54 °F (8-12°C).

The cooled water that returns to the cold aquifer is a by-product of heat production, however, just as useful in terms of meeting cooling demands in the DC network. Depending on the temperature of the cold water aquifer, cold water can be drawn with one of two purposes:

1. To "free cool" the return water from the DC network down to design temperature of 46°F (8°C), that is if temperature in the aquifer is lower than 46°F (8°C).

   OR

2. to pre-cool the return water as much as possible before cooling to design temperature in the chillers (called partial free cooling or integrated free cooling).

Thus, introducing ATES in the system creates great synergy between summer and winter production.

4.2.3 Sizing of production capacity

Based on the energy demands described in section 2 we have simulated the DHC concept using Energy Pro software. For now, only demand from the fully built-out site has been simulated.

By simulating the energy demand of the site in line with available weather data for the City of St Paul (incl. irradiance model), we can provide an initial indication of the possible major plant sizes, i.e. solar thermal, heat pumps, chillers, short term thermal energy storages (TES) etc.

Whereas the required capacity in the individual scenarios is the sum of capacities for all the buildings, the required capacity in the DHC scenario must be factored to take into account that peak demands will not occur in all of the buildings at the same time. This is one of the major advantages of district energy because it enables us to decrease level of investment for production capacity.

The EnergyPro model factors this automatically, and the required peak capacity is reduced compared to the totalled peak capacity shown in the individual concept (Table 8).

The reason for the cooling capacity installed is only reduced by 5 % compared to the individual scenario is due to the fact that a 80% outdoor temperature dependency is assumed in the EnergyPro model.

The outdoor temperature dependant (OTDS) share of the cooling demand might be lowered significantly depending on how much light process (e.g. servers etc.) that eventually will be introduced in the system. Lower outdoor temperature dependency implies less required peak capacity installed.

Sensitivity: Setting the aforementioned dependency share at 70% instead of 80% gives a 17% reduction on the required production capacity.

Table 12 Reduced peak capacity

	Peak Heat load	Peak Cooling load
Individual concept	26,390 MMBtu/hr (7.73 MW)	20,414 MMBtu/hr (5.98 MW)
DHC concept	13,140 MMBtu/hr (3,85 MW)	19,150 MMBtu/hr (5,7 MW)
Capacity Reduction	~51%	~5% (~17% with OTDS at 70%)

To ensure security of supply an N + 1 approach is taken, meaning that the biggest unit can fail (back up unit of equal size is installed).

ATES is assumed to have the required capacity to meet demands in the heat pumps and chillers at all times.

Energy losses in the network have been calculated using a certified Logstor model. Energy loss in the DHC network is in the order of 6% for heating & 2% for cooling.

A schematic overview of the system components can be found in Table 13.

Table 13 Concept 3 Specifications

District Energy Concept	District Heating				Combined heating/ cooling	District Cooling		
Plant type	**Solar thermal**	**Heat pump**	**Natural gas boiler**	**Thermal Store**	**Heat pump**	**ATES Free Cooling**	**Chiller**	**Cold Store**
Plant size	5250 m2	3 x 1MW	1 x 4MW	600m3	1 x 500 kW	1 x 2MW	3 x 2MW	1725m^3
Plant efficiency	Covers approx. 30% of yearly heat demand	600%	94%	-	800%	4000% (only pump)	500%	-

An indication of the annual contribution that each production unit makes to the total energy production is presented in Figure 4 and Figure 5 (below).

The black curve (duration curve) indicates the demand at any given hour of the year. The reason why heat production is way above the aforementioned peak production capacity is because solar thermal production is highly fluctuating (very large peak in limited amount of hours during summer) and that the excess heat (above actual demand) is stored in the short term thermal storage.

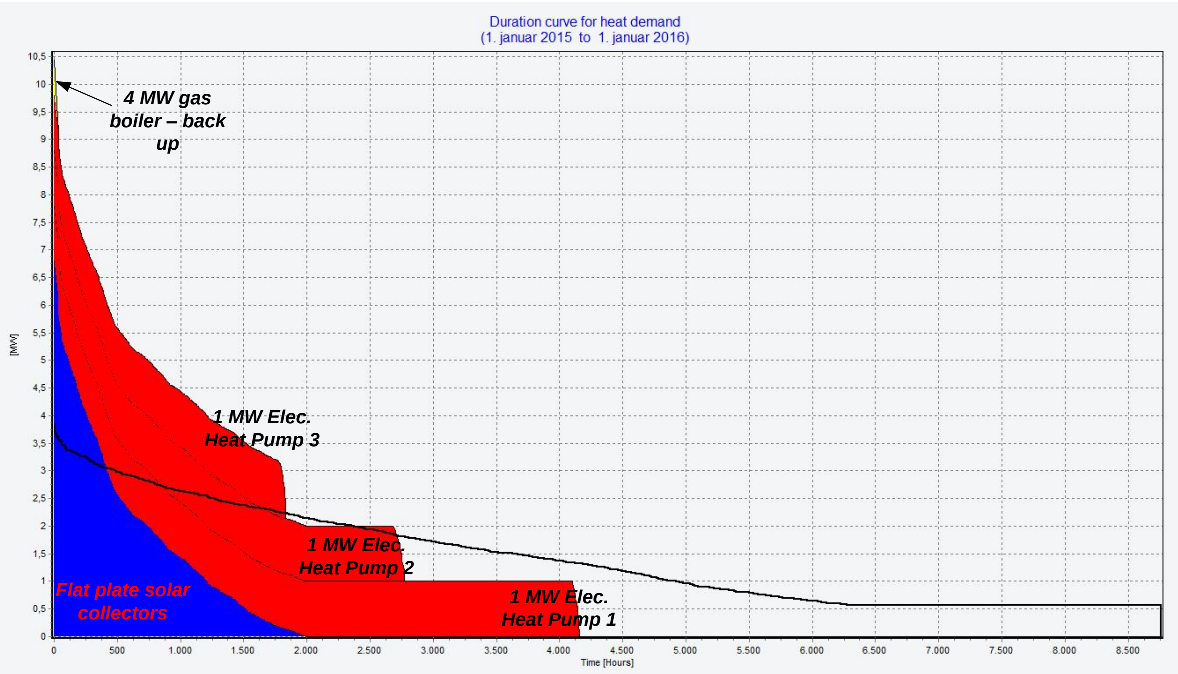


Figure 4 Heat Duration Curve with Productions from solar thermal, heat pumps and Ngas boiler

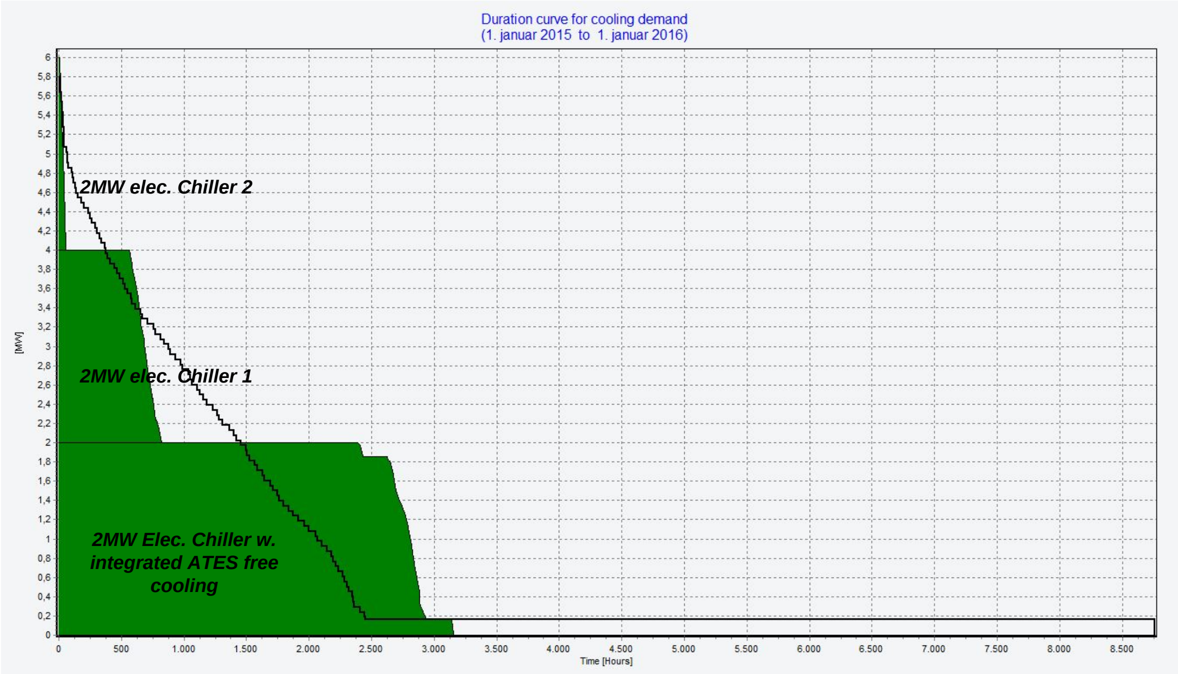


Figure 5 Cooling Duration Curve with Productions from ATES free cooling and chiller plants

The non-coloured area is where demand is met by thermal storage.

The yield of the flat plate solar thermal is based on an actual irradiance model for the area of St Paul (and Ramboll's general experience).

Short term thermal storages have been sized to optimize solar fraction in the system and to allow for economic optimization according to the day-ahead electricity market. The night time electricity tariff (between 9 pm and 9 am) is approx. 50% of the day time tariff, making it favourable to operate heat pumps and chillers in the evening or night time.

Energy production will be on a modulated approach with smaller units added on as the site is build out to delay CAPEX.

4.2.4 DHC Network

Network dimensions have been chosen based on a hydraulic modelling of the proposed DHC concept. The district energy network is presented in Figure 6.

Figure 6 the district energy network

At this stage we envisage a low temperature DH network will be employed with the following design parameters:

Design temperature:	185 or 203°F (85 or 95°C)
Design Pressure:	87 or 145 psi (6 or 10 bars)

It should be noted that these temperatures require a different design to the secondary systems than is normal practised in the US.

Pre-insulated pipes have been assumed for both the heating and cooling network.

Pre-insulated pipes are a necessity in the DH network in terms of energy efficiency (large temperature difference to the ambient meaning large heat losses). However, for the DC network un-insulated plastic pipes could be used instead because temperature difference between the cooling water and the ambient is very small (low energy losses in general).

Plastic pipes incur a significantly lower investment in the piping network, however, it should be noted that using un-insulated pipes limits the options regarding leak detection.

If steel pipes are chosen for the DC network insulation could be required to prevent condensation on the outside of the pipe (prevents corrosion).

4.3 Concept 2: Individual Renewable Energy Supply

This concept is a further development of the BAU case described in concept 0. Heating and cooling production is individual (IND) for each building unit and as close to 100% RES integrated.

4.3.1 Energy Production

Individual heating and cooling by Heat Pumps and Chillers respectively, with immersion heaters installed as back up.

Solar PV panels are integrated into the building mass to increase RES in the overall concept. Solar PV is installed on a maximum of 40 % of the individual building foot print with an additional constraint that the yield of the solar PV (MWh produced/year) must not exceed the total electricity consumption of the heat and cooling production in the individual building.

A net-meter arrangement is assumed, allowing excess production to be absorbed in the public electricity network and bought back at zero cost.

The specification for the Solar PV is taken from the EPA Rooftop PV report.

Alternatively, we propose the Solar PV panels could be located centrally at the concrete sealed area next to the river. A total of about 40% of the site area (approx. 4 acres) of solar Photovoltaics could be installed. This solution would probably be much cheaper that integrating it into the building mass.

The electricity produced by the PV-panels, will be used for the heat pump and chillers in each building. It is assumed that the price of the supplied electricity corresponds to the industrial tariff.

Heat pumps are expensive and during peak hours it would be necessary to install a high amount of capacity. An alternative to peak production for heat pumps is gas boilers, but to avoid establishing a natural gas network and paying an increased price during peak hours, an oil-fired boiler is assumed instead. This serves as peak load boiler and is expected to cover 30% of the heating demand annually.

Table 14 Concept 2 Specifications

Individual Concept	Heating		Cooling	Electricity
Plant type	Heat Pump Individual or Common	Oil-fired boiler (as back-up)	Chiller Individual or Common	Solar PV + Grid
Plant size, MW	Depending on Building type and size		Depending on Building type and size	Depending on roof space
Plant efficiency, %	500%	95%	400%	-
Operating hours	1800		1200	1300[3]

5. FINANCIAL ASSUMPTIONS

5.1 Overall general assumptions

For the analysis Ramboll has use the following financial inputs.

Parameter	Ramboll suggestion
Start year	2019
Inflation	3%
Discount rate (WACC)	7.3%

[3] Assuming a little less than the maximum production (1400) mentioned in the EPA report.

We consider the discount rate calculated in nominal terms (includes inflation) i.e. all calculation will be made on nominal basis. All prices will therefore be inflated during the calculation period.

It is assumed that the value of all investments is zero after 25 years.

5.2 Concept 0: Business as Usual Financial assumptions

The financial assumption for concept 0 is presented in Table 15.

Table 15 Concept 0 Financial assumptions

Individual Concept	Heating	Cooling
Plant type	Natural gas boiler Individual or Common	AC unit Individual or Common
Plant efficiency, %	94% (HHV)	400% (COP = 4)
Equivalent Full Load Hours	1800	Retail, office, civic: 1500 Apartments: 1200
Capex	XX (280$/kW[4])	Apartment: $ 6.50 MMBtu/h ($1,919/kW) Retail: $ 6.10 MMBtu/h ($1,791/kW) Office: $ 9.30 MMBtu/h ($2,730/kW)[5]
Service & Maintenance[6]		
Retail/Mixed use	400 $/unit/yr	400 $/unit/yr
Apartment/Condo-High Density	400 $/unit/yr	400 $/unit/yr
Official/Institutional	500 $/unit/yr	500 $/unit/yr
Civic	400 $/unit/yr	400 $/unit/yr
Apartment/Condo-Medium Density	300 $/unit/yr	300 $/unit/yr
Apartment/Condo-Low Density	300 $/unit/yr	300 $/unit/yr

The variable and fixed costs of maintenance are included in the service and maintenance costs.

A natural gas network is established throughout the new development area. The single consumer pays a price for the natural gas which includes a natural gas network.

Xcel Energy assumes that the loads will trigger the revenue justification formulas that would allow the natural gas ratepayers to absorb these costs. Hence, the investment for gas network will not be included in the financial model.

5.3 Concept 1: District Heating and Cooling Financial assumptions

A schematic overview of the system components can be found in Table 16.

[4] Danish Energy Agency, Technology Data for Energy Plants, Individual Heating Plants and Energy, October 2013

[5] TAG committee comments Ken Smith email 8th of May 2015

[6] TAG committee comments Ken Smith email 8th of May 2015 + Ramboll assumption

Table 16 Concept 3 Specifications

District Energy Concept	District Heating				Combined heating/ cooling	District Cooling		
Plant type	**Solar thermal**	**Heat pump**	**Natural gas boiler**	**Thermal Store**	**Heat pump**	**ATES Free Cooling**	**Chiller**	**Cold Store**
Plant size	5250 m^2	3 x 1MW	1 x 4MW	600m^3	1 x 500 kW	1 x 2MW	3 x 2MW	1725m^3
Plant efficiency	Covers approx. 30% of yearly heat demand	600%	94%	-	800%	4000% (only pump)	500%	-
CAPEX/plant[7]	375$/$m^3$	2.92 M$/MMBtu/h (0.85 M$/MW)	0.6 M$/MMBtu/h (0.175 M$/MW)	200$/m3	4.75 M$/MMBtu/h (1.39 M$/MW)	$1,000,000	1.79 M$/MMBtu/h (0.52 M$/MW)[8]	200$/$m^3$
OPEX		0,1% of CAPEX	0,05% of CAPEX	-	0,1% of CAPEX	0,1% of CAPEX	0,1% of CAPEX	-

Flat plate solar thermal is based on irradiance model for the area of St Paul and Rambolls general experience.

Short term thermal storages are sized to optimize solar fraction in the system and to allow for economic optimization according to the day-ahead electricity market. Night time electricity tariff (between 9 pm and 9 am) is approx. 50% of day time tariff making it favourable to operate heat pumps/chillers in the evening/night.

Energy production will be on a modulated approach with smaller units added on as the site is build out to delay CAPEX.

[7] TAG committee comments, 8th of May 2015

[8] Ramboll District Cooling feasibility studies

A cooling and heating substation will be placed in each building. The CAPEX and OPEX are presented in Table 17.

Table 17 CAPEX and OPEX of District energy substations

Plant type	DH unit	DC unit
CAPEX/plant[9]	0.76 $/MMBtu/h (224 $/kW)	0.76 $/MMBtu/h (224 $/kW)
OPEX[10]	134 $/unit/year	134 $/unit/year

Installed district energy pipe prices are assumed to be approximately for green field conditions as presented in Table 18.

Table 18 Prices pipes installed

Pipes	DN (mm)	32	40	50	65	80	100	125	150	200	250	300
Heating/ Cooling	$/ft	350	375	425	500	525	550	575	600	730	920	1130
Heat loss	w/m	17.74	21.15	23.48	26.44	27.98	29.18	28.52	37.95	44.47		
Cooling loss	w/m				2.14	2.27	2.37	2.68	3.08	3.61	3.53	4.02

Above prices assume separate installation of heating and cooling pipes which increases the prices by $100/ft each. Simultaneous installation is assumed for the financial analysis.

It is estimated that coordination of installation with other infrastructure and utilities will save another 30% in installation cost. This is not assumed for the analysis, but investigated through a separate sensitivity analysis.

Overheads added to the district energy network are presented in Table 19.

Table 19 overheads for the district energy network

Overhead	%
Admin	0.05
O&M	0.1
Power demand for network	1

[9] Danish Energy Agency, Technology Data for Energy Plants, Individual Heating Plants and Energy, October 2013

[10] Danish Energy Agency, Technology Data for Energy Plants, Individual Heating Plants and Energy, October 2013

5.4 Concept 2: Individual Financial assumptions

The financial assumptions regarding concept 2 are presented in Table 20.

Table 20 Concept 2 Specifications

Individual Concept	Heating		Cooling	Electricity
Plant type	Heat Pump Individual or Common	Oil-fired boiler (as back-up)	Chiller Individual or Common	Solar PV + Grid
Plant size, MW	Depending on Building type and size		Depending on Building type and size	Depending on roof space
Plant efficiency, %	500%	95%	400%	-
Operating hours	1800		1200	1300[11]
CAPEX/plant, Installed effect	2.73 $/MMBtu/h (800$/kW)	9,400 $/unit[12]	$6.8-13.6/MMBtu/h ($ 2,000-4,000/kW)[13]	6 $/MMBtu/h (2,000$/kW[14])
Maintenance	450$/unit/yr	390 $/unit/year[15]	300 $/unit/yr	-

To the heat pump CAPEX a cost of $150,000[16] per building are added to cover the expenses for ground source heating for heat pump,

5.5 Operational costs and tariffs

Several additional components are needed to complete price assumptions of the analysis.

5.6 Energy prices

The following energy prices are assumed.

Natural gas prices, for energy plants in DH Concept and for end users in BAU Concept. Three different price levels dependent on customer type are assumed (DH company, commercial/retail, residential). The price is for the base year (2016), and is adjusted annually by the chosen rate of inflation.

Flat rate prices are assumed for all utilities except electricity for the district energy company.

Table 21 Energy Prices ($/MWh)[17]

	Residential	Commercial/Retail	Industrial	District energy utility
Natural gas	23,5	21,5	16,5	16,5
Electricity	148	139	117	-
Oil	31	31	31	-

Commercial/retail prices are applied for electricity used for chillers, and heat pumps in concept 1 DHC.

[11] Assuming a little less than the maximum production (1400) mentioned in the EPA report.
[12] Danish Energy Agency, Technology Data for Energy Plants, Individual Heating Plants and Energy, October 2013
[13] Depending on size, Ramboll District Cooling feasibility studies
[14] Assuming the average cost projections for 2019, p. 23 of the EPA report.
[15] Danish Energy Agency, Technology Data for Energy Plants, Individual Heating Plants and Energy, October 2013
[16] Based on Ramboll experience from similar project
[17] Xcel Energy, John Marshall, May 7th 2015 by email

The oil for the oil-burner peak load, will be available for both residential and commercial at the same price, as a larger block central oil boiler is assumed rather than smaller individual oil boilers.

All energy prices presented in Table 21 are added a price increase of 3% per year, corresponding to the assumed inflation.

5.7 Electricity for the district energy utility

Basically two demand charges appear, one for peak hours (9am-9pm on weekdays) and one for off-peak hours.

The rates assumed are based on information from Xcel Energy, and are as follows:

Rate,	Peak	Off-peak
$/MWh	77.12 (81.69)	45.42 (48.11)[18]

The share between Peak and Off-Peak hours are assumed at:
Peak: 30%
Off-peak: 70%
A 5.9% price increase per year.

Fixed charges are anticipated at about 13.963 $/MW/month and 9.853 $/MW/month for summer and winter periods respectively.

6. RESULTS

6.1 Concept 0, Business as Usual

The Business As Usual Concept is used as a reference Concept, for comparison between the three Concepts. The assumptions regarding the BAU Concept are described in section 4.1.

In order to compare the BAU concept with the other two concepts, a weighted average price per MMBtu heating and cooling was calculated based on the total investment and all cost during the entire project lifetime. The share between heating and cooling are presented in Figure 7.

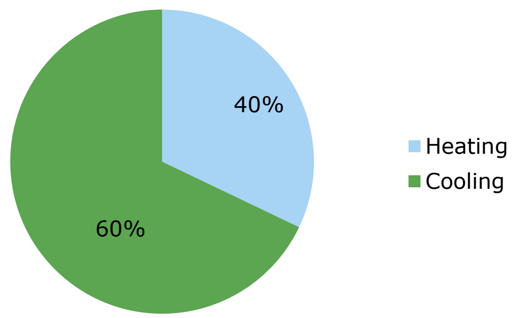


Figure 7 the share of costs and investment between heating and cooling in Concept 0

The reason for cooling has a larger share than heating is due to the high investment cost in chillers compared to the investment cost for gas boilers. The different costs and investment included when calculating the heating and cooling prices are as following:

- Gas for boilers
- Service and maintenance
- Electricity for chillers
- Network investment
- Gas boiler investment

[18] Including 5,9% add on of May 2015 class rate increase

- Chiller investment

The heating and cooling costs per MMBtu are presented in Table 22. The calculated costs of energy per MMBtu cooling and heating are the weighted costs the consumers will pay in order to be supplied with both heating and cooling seen over a lifespan of 25 years.

Table 22 energy cost pr. MWh heating and cooling in BAU Concept

Energy	Cost pr. energy unit
Heating	243 $/MMBtu (71 $/MWh)
Cooling	1000 $/MMBtu (294 $/MWh)

With the calculated reference heating and cooling price, the results of the BAU Concept are as presented in Figure 8. Given the calculated average price of heating and cooling, the BAU concept will, as expected, result in a Net Present Value (NPV) of $0 (accumulated discounted cash flow) and an Internal Rate of Return at 7.3%. An overview of revenues, costs, investments, and the accumulated discounted cash flow are presented in **Error! Reference source not found.**.

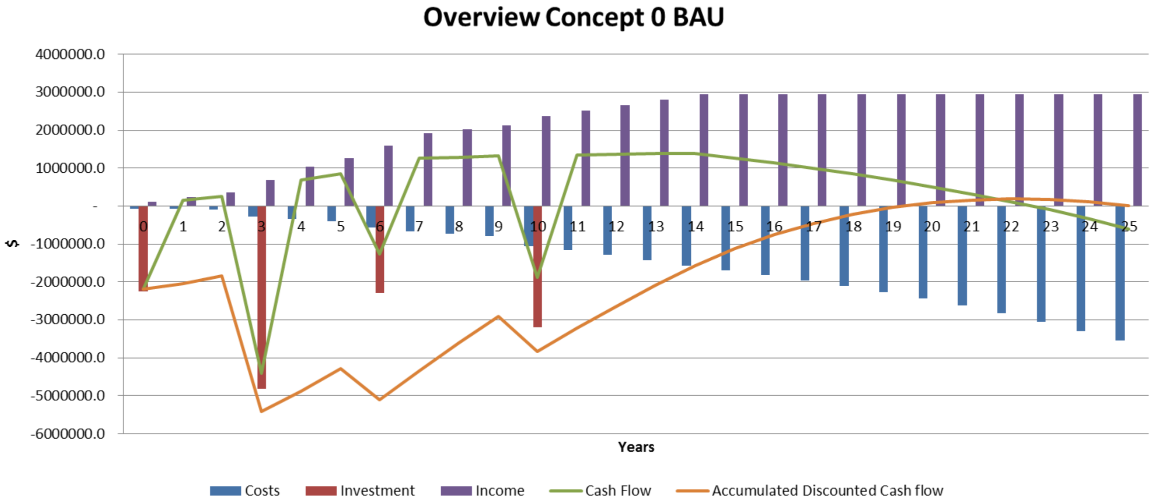


Figure 8 Overview concept 0 BAU

The detailed cash flow is added in Appendix 8.2. From the cash flow it is evident that the largest costs are the investment in chillers, and the energy cost of gas of $7.5M and $4.6M respectively. The net present value of the total investment for concept 0 BAU is $8.6M.

6.2 Concept 1, District Energy

Previously mentioned, the heating and cooling $/MMBtu from Concept 0 BAU will be applied 1:1 as the actual heating and cooling price in the District Energy Concept.
However it is important to note, for the customer to have incentives to connect to the network, a lower price than business as usual energy supply could be used. This lower price should be taken into consideration if a district energy concept is further developed.

By adding an income responding to the cost of energy per MWh in the reference BAU Concept, a comparison between the two can be executed.

The overall results are presented in Table 23, with the net present value (NPV) and Internal Rate of Return (IRR).

Table 23 the result of concept 1

	NPV	IRR

Concept 1, DHC	$-6.1M	3.81%
Total investment	$ 23M	-

As the table indicate concept 1 has an overall negative result of $6.1M, which is largely caused by the investments of $23M, which also is presented in Table 23, while the shares of investments are illustrated in Figure 9.

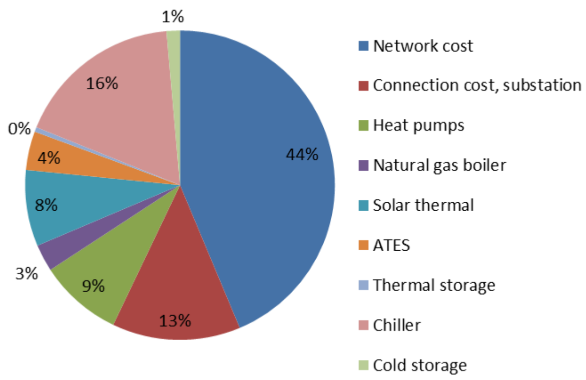


Figure 9 The share of investment for concept 1

The main contributor to the overall total investment is the network, comprising both the heating and cooling network. While the chillers and substations accounts for 16% and 13%, respectively.

The cash flow is included in Appendix 8.3.

As the cash indicate the service and maintenance cost of all production units are rather low compared to the electricity costs at $2.9M and the positive cost for the reduction in building space of around $2.3M.

The overview of concept 1 is illustrated in Figure 10.

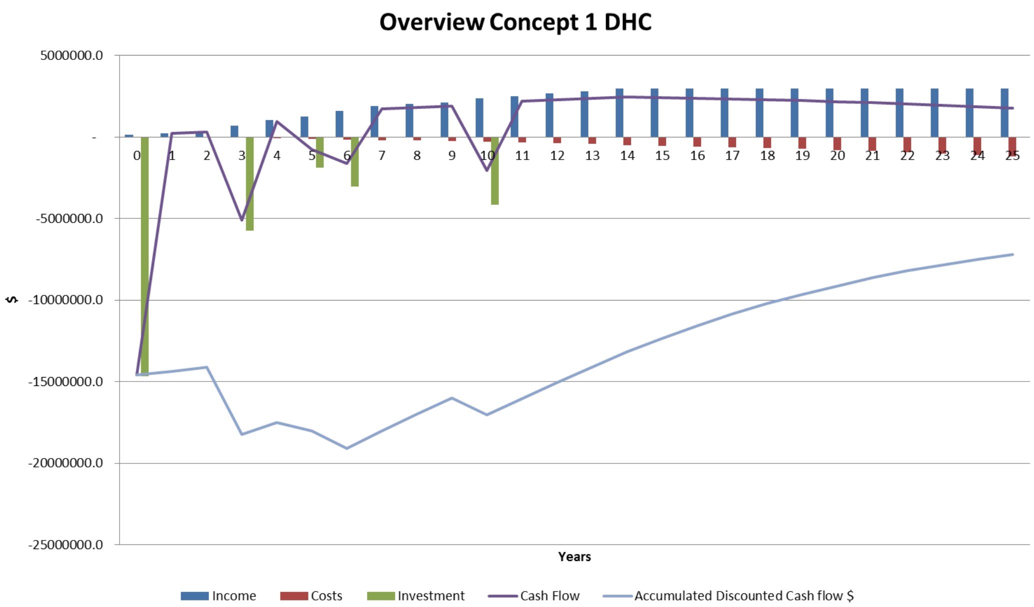


Figure 10 Overview of concept 1 DHC

As the figure indicates, the concept is slowly going towards a break even, with only a slightly higher annual income than costs, however it is not possible within the project evaluation time due to the value of the investments. But the project lifetime is longer than the evaluation period.

6.3 Sensitivity analysis Concept 1 – District Heating and Cooling

A sensitivity analysis was carried out for concept 1, in order to analyze the different parameters and their influence on the final results. Table 24 present the chosen factors, and their corresponding interval. The intervals indicate how the parameters will be changed to see the effect on the result.

Table 24 Parameters used in sensitivity analysis

Name	Start	High	Low
Discount rate (WACC)	7,3%	10,0%	3,0%
Network investment	100%	130%	70%
Substation costs	100%	150%	50%
District Energy price	100%	120%	80%
Residential, EqFLH	1200	1500	900
Electricity on/off peak	70,0%	100%	0%
Heat pump investment	100%	120%	80%
Gas boiler investment	100%	120%	80%
Chiller investment	100%	120%	80%
Solar thermal investment	100%	120%	80%
ATES investment	100%	120%	80%
Electricity price increase	5.6%	5.6%	0%
Internal rate of return	7.3%	7.3%	3%

The results of the sensitivity analysis are presented in Figure 11. The parameters are examined one at the time, to see their individual affection on the result.

The figure should be read as following: The overall NPV of concept 1 is represented by the reference line in the figure. The high and the low columns indicate the NPV if the given parameter was changed to the higher or lower value, as already presented in Table 24. The high and low values could also be called best and worst case scenarios. As example, the NPV is around $ -6.1M now, if the network investment is increased with 30% the NPV would be around $-8M, and if the investment was decreased with 30% the NPV would be $-5M.

The parameter with the larges sensitivity is the energy price, accounting for both the cooling and heating. If the heating and cooling prices are 20% higher than the current reference price, the concept will have an overall result of around $-11M.

As mentioned in the section about the network cost, a sensitivity regarding saving 30% of network investment is included. As the figure below indicates, the final result will be affected when lowering network investment with 30%.

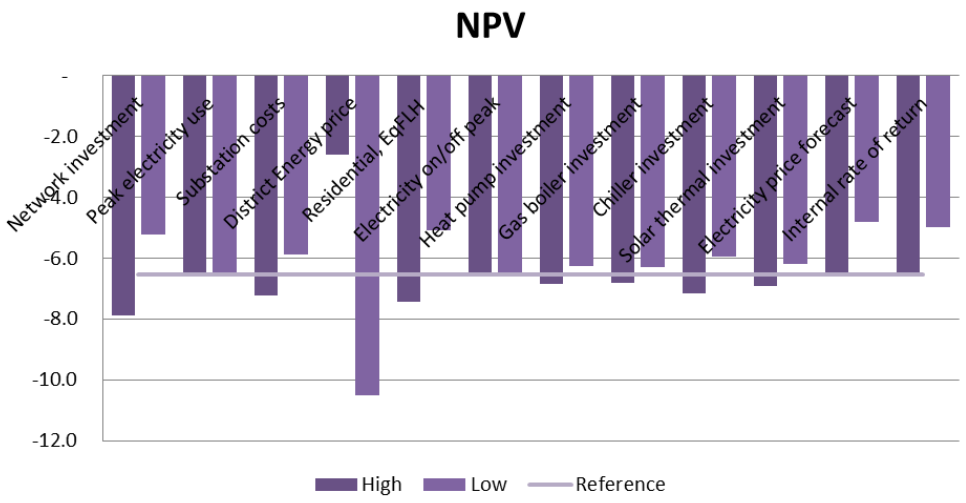


Figure 11 Results of sensitivity analysis of concept 1

The equivalent full load hours for residential buildings will also have a rather high impact on the viability of the concept.
The investment in the different energy producers has a relatively low impact on the result of the concept.

6.4 Concept 2, Individual

Again the reference heating and cooling price from concept 0 is used as the price the costumers will pay. However since the ford site will be developed from the ground, a price index of 1:1 is assumed. The overall results are presented in Table 25.

Table 25 result of concept 2

	NPV	IRR
Concept 2, IND	\$-5.7 M	3.13%
Total investment	\$19.7M	-

Concept 2 has a negative net present value of \$5.7M compared to concept 0 BAU. The main reasons for that is the larger capital investment cost in concept 2.

The cash flow is added in Appendix 8.4.

As the cash flow indicates the overall significant post in the cost of the Individual concept is the investment in chillers with \$10M. Furthermore the investment in PV panels and costs of electricity are rather significant, costing \$3M and \$4M respectively.

Even though each building will have solar PV panels, some buildings are not able to produce enough to cover the electricity demand from the heat pump and chillers in the buildings. Hence, some electricity must be bought from the grid.

The shares of the investments are presented in Figure 12.

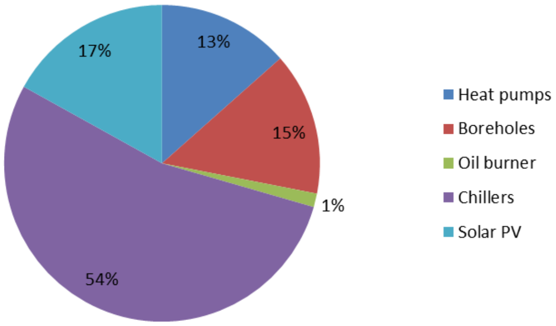


Figure 12 share of investment for concept 2

The main investment is the chillers with more than 50% of the total investment. While the heat pump, boreholes for the heat pumps and solar PV panels are around 15% with the oil burner unit at just 1%.
The overall overview of concept 2 is illustrated in Figure 13.

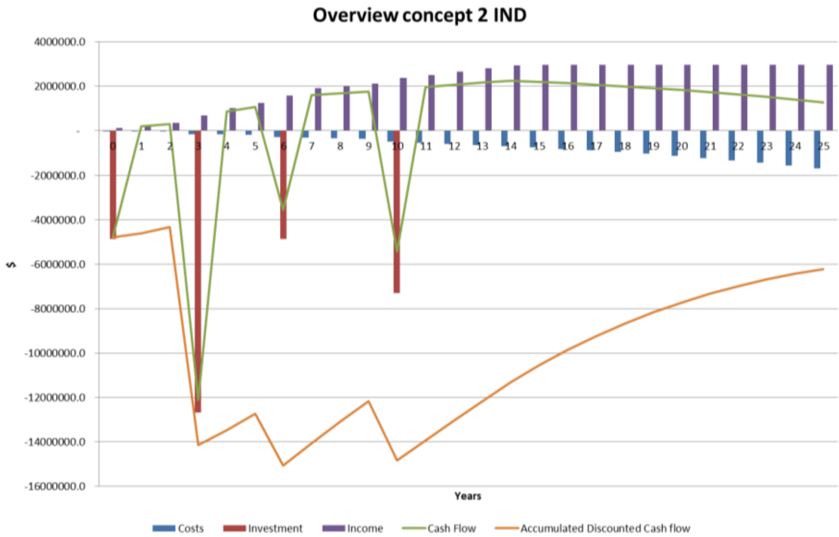


Figure 13 Overview Concept 2 Individual renewable energy supply

As the figure indicate is concept 2 not viable within the lifetime of the project.

6.5 Sensitivity analysis Concept 2 – Individual

The sensitivity analysis was also carried out for concept 2. The chosen parameters are presented in Table 26 below.

Table 26 Parameters used in sensitivity analysis

Name	Start	High	Low
Residential, EqFLH	1200	1500	900
Heat pump investment costs	100%	120%	80%
Service heat pump	100%	120%	80%
PV panel investment costs	100%	120%	80%

Chiller investment costs	10%	120%	80%
Service chillers	100%	120%	80%
Electricity price forecast	3%	4%	2%
Internal rate of return	7.3%	7.3%	3%

Figure 14 below illustrate the results of the sensitivity analysis. As expected the viability of concept 2 is rather sensitive to changes in investment cost of the chillers. Other relevant parameters are the investment cost of the PV panels and heat pumps. Whereas the service and maintenance cost for both the heat pump and the chillers do not have any significant influence.

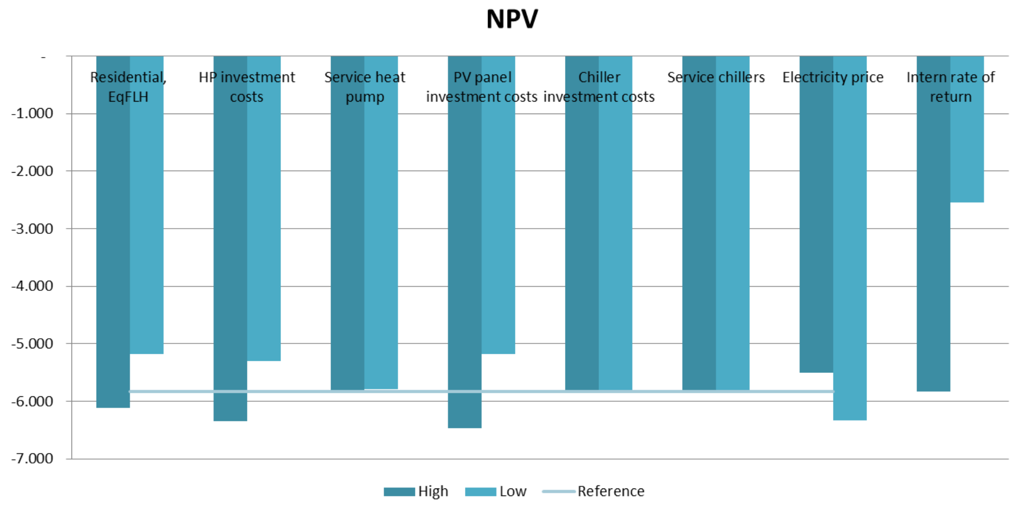


Figure 14 Results of sensitivity analysis

Again the equivalent full load hours for residential buildings will also have an impact on the viability of the concept.

The amount of produced electricity from the PV panel was not included in the sensitivity analysis, however it is expected to have a significant influence on the viability of the concept, hence more electricity must be purchased from the grid, and the cost will increase.

6.6 CO_2 calculations

The CO_2 accounts for each concept are calculated and presented in Figure 15. The kg CO_2 equivalents used for the calculations are included in Table 27. The Electricity provided from the grid has the highest contents of CO_2, while the content of natural gas is somewhat smaller than the oil.

Table 27 CO_2 equivalents for electricity, oil and gas

Natural gas[19]	450	lbs CO_2 eq./Mwh	204	kg CO_2 eq./MWh
Electricity, Grid[20]	1,292	lbs CO_2 eq./Mwh	586	kg CO_2 eq./MWh
Oil[21]	620	lbs CO_2 eq./Mwh	281	kg CO_2 eq./MWh

It is evident from the results of the calculations that the BAU concept has the highest CO_2 emission during the project evaluation period, while concept 1 DHC has the lowest.

[19] www.Energinet.dk – Danish Energy Angency, http://www.energinet.dk/DA/KLIMA-OG-MILJOE/Energi-og-klima/Naturgas-og-klimaet/Sider/default.aspx
[20] Xcel Energy, 2014 Carbon Dioxide (CO_2) Reporting Worksheet
[21] www.Energinet.dk – Danish Energy Angency, http://www.energinet.dk/DA/KLIMA-OG-MILJOE/Energi-og-klima/Naturgas-og-klimaet/Sider/default.aspx

If taking a cost of CO_2 emission per kg into consideration in this project, it will influence the overall results of each concept and add the most value to concept 1 DHC. When fully built out, the BAU concept would have to pay for around 3,500 tons of CO_2 equivalents per year and concept 1 DHC around 1,200 tons of CO_2 equivalents per year. The potential added value to concept 1 DHC will depend upon the given price of 1 kg CO_2 equivalent.

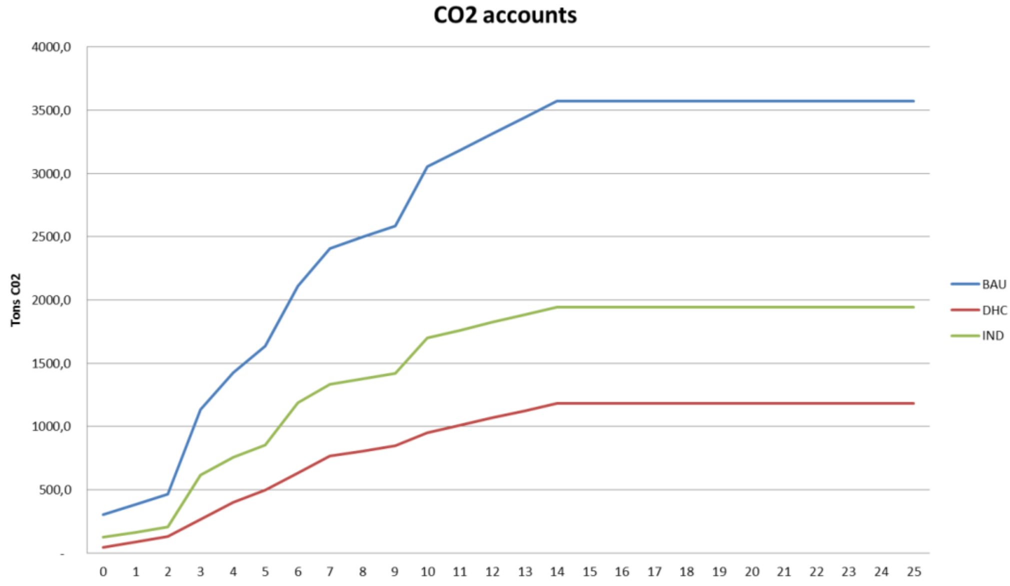


Figure 15 CO_2 accounts for all three concepts

6.7 Share of renewables

The share of renewables in each concept is calculated based on the demand for heating and cooling for all buildings.

With regard to electricity from the grid, the production composition is presented in Figure 16. The CO_2 neutral electricity is equal to 34%. Energy supplied from gas and oil is assumed 0% renewable. Electricity from the local PV panels are assumes 100% renewables, as accounts for the heat produced from the solar thermal plant.

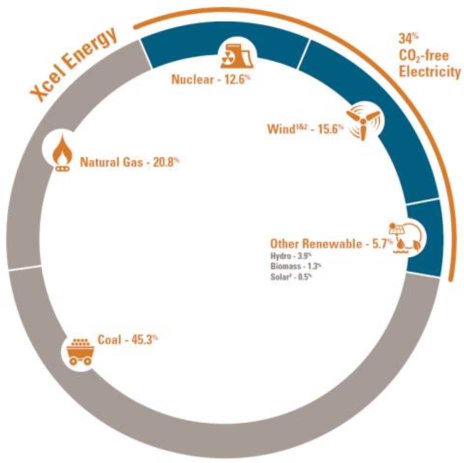


Figure 16[22] Share of renewables in electricity from the grid

[22] Xcel Energy, 2014 Carbon Dioxide (CO_2) Reporting Worksheet. The figures are presumable based on average content of renewable energy but the electricity consumption in the DHC scenario is predominantly used in off peak hours in which the share is expected to be higher

With the mentioned assumptions the share of renewables for each concept can be calculated. This is done by using the energy demand, the COP of both heat pumps and chillers and efficiency of gas boilers and oil-burners. The numbers are presented in Table 28.

Table 28 share of renewables for each concept

Concept	Share of renewable
BAU	27%
DHC	90%
IND	84%

The share of renewables is highest for concept 1 with 90%. This is due to the use of solar energy for heating and high COP for both the heat pumps and the chillers, hence when 1 unit of energy is used in the heat pump 5 units are produced.

Concept 2 also has a rather high share of renewables, 84%, due to the use of PV panels for electricity production, a COP of 5 for the heat pump and the use of free cooling.

With regards to the share of renewable in energy production, concept 1 DHC can defiantly provide the best result.

6.8 Potential Renewable Energy Certificate sales[23]

Although sales of Renewable Energy Certificates were not included in the economic analysis, there is great potential to offset costs in the DHC and IND concepts through the sale of Renewable Energy Certificates (RECs). These credits are equivalent to 1 MWh of renewable energy. The sale of RECs in both compliance and voluntary markets for the state is done through the Midwest Renewable Energy Certification System (M-RETS). Minnesota has adopted one of the highest standards in increasing renewable energy through a Renewable Portfolio Standard (RPS), 25% by 2020. Xcel Energy, Minnesota’s largest utility company and the energy and gas supplier for St. Paul, is required to source 30% of energy from renewables by 2020. Furthermore, the voluntary REC market is expanding with customer purchases of “green energy” and Minnesota is one of the top states in terms of sales (Heeter 2010). Thus, there is a huge potential for future demand for RECs in both compliance and voluntary markets. Including the sale of RECs in future analyses could alter results of the feasibility study.

[23] Status and Trends in U.S. Compliance and Voluntary Renewable Energy Certificate Markets (2010 Data), Jenny Heeter and Lori Bord, National Renewable Energy Laboratory, October 2011

7. COMPARISON, CONCLUSION AND FURTHER RECOMMENDATIONS

The main goal of activity 1.7 was to outline the concept design for three technical solutions, and furthermore compare their financial viability. With a reference energy price for the customers, a comparison between the three concepts was carried out.

As the results section present, concept 1 has a net present value of M$-6.2 and concept 2 M$-5.8, both results are based on the reference heating and cooling price from concept 0. However both results have a positive internal rate of return.

Many parameters and assumptions will influence the result; furthermore willingness toward renewable energy solutions should also be taken into consideration. The most sensitive assumptions included in the analysis are the district energy prices (based on the BAU concept) and the network investment cost for concept 1 DHC. For concept 2 IND the most sensitive assumptions are the investment costs of chillers and solar PV panels.

The most noteworthy cost for concept 1 is the cost of electricity for heat pumps and chillers. Even though the heat pump and chillers has a high COP of 5 and 6, the cost is relatively high due to the high electricity price.

Investments in energy producing units are the most significant parameters influencing the result for both concept 1 and 2. For concept 1 the network costs are the largest investment with around $10M, based on the pipe prices. Several things should be kept in mind when choosing pipe size and types such as choice of pipe material (plastic or pre-insulated steel pipes), and size with regards to pressure drops. With that in mind, a possible reduction of CAPEX for concept 1 can be accomplished.

It is also important to mention the reference prices for heating and cooling. Currently they are used 1:1 in both concept 1 and 2. Normally when an energy source is changed for a specific area, it is expected that the customers need an incitement in order to change from one source to another (e.g. from gas to district heating). Usually the incitement is a reduction in energy costs.

In the calculation it is assumed that all the investments have a lifetime of 25 years and the end value is zero. For the network however the technical lifetime is often more than 40 years.
If the new energy source has a very high share of renewable some customers may be willing to pay a higher price than the alternative energy source, with a low share of renewables. However, this is only guesswork in the current state. As already mentioned, sales of renewable certificates can affect the price of energy considerably.

An income of some kind could be added, corresponding to the share of renewables in order to compensate concept 1 and 2 for their share of renewables and low CO_2 emissions.

Another parameter that should be mentioned is the electricity price increase at 5.9%. This is a relatively high increase compared to other forecasts, and should be taken into consideration for further analysis. The electricity price is rather significant for the results of concept 1, as already presented in the sensitivity model results, since electricity is used for both heat pumps and chillers. For concept 1 it is foreseen that heat pumps and chillers predominantly are in operation during nighttime with low electricity prices. Heating and cooling is produced to storages.

Use of subsidies tariff and similar are not included the project since they are not constant, and will change over time due to political decisions. However, the potential subsidies, grants or other similar parameters should be included when deciding which concept(s) to include in further investigations.

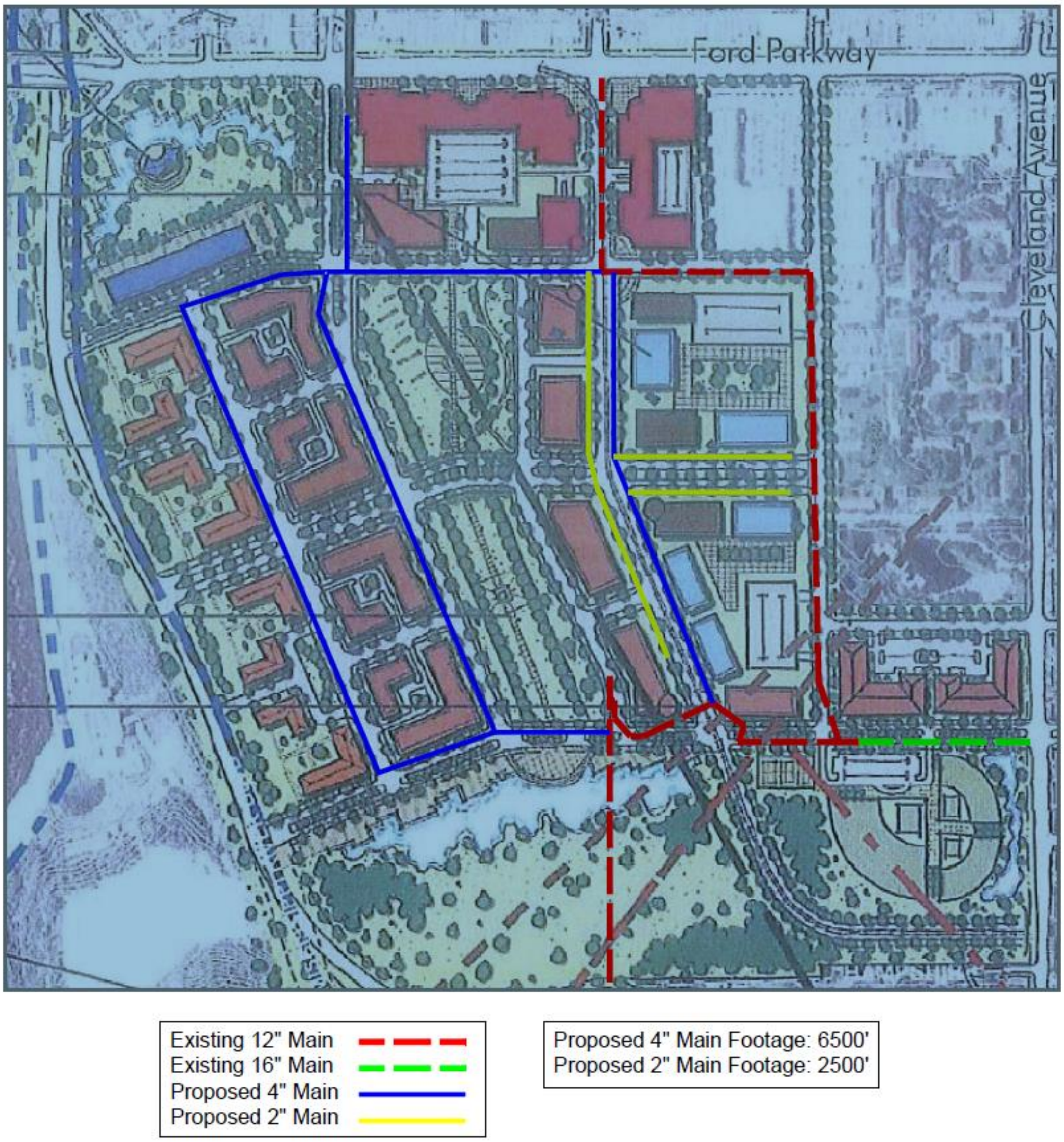
Important parameters that Ramboll suggest further investigation off:

- Pipe prices
- Electricity forecast
- The potential for ATES in the area
- Renewable energy certificate potential sales
- Investigate investment in chillers, both large (2MW) and smaller (60 kW)

Regarding ATES, we assume that it is possible in the area, but we would recommend that a hydrogeological desktop study is being carried out.

8. APPENDIX

8.1 Gas network



8.2 Concept 0 – BAU

Cash flow

Cashflow BAU																		
			Sequence	0	1	2	3	4	5	6	7	8	9	10	11	23	24	25
	unit	Base	Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2042	2043	2044
		3%	price index	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.97	2.03	2.09
Income			**NPV**															
Heating	$		5,809,359	28,548	57,097	85,645	186,366	287,086	359,258	462,711	566,163	597,444	628,725	704,764	749,522	883,796	883,796	883,796
Cooling	$		13,902,160	87,759	175,519	263,278	503,919	744,560	897,442	1,122,202	1,346,963	1,418,841	1,490,720	1,663,096	1,763,594	2,065,086	2,065,086	2,065,086
Sum	$		57,039,794	116,308	232,616	348,924	690,285	1,031,646	1,256,700	1,584,913	1,913,126	2,016,286	2,119,445	2,367,860	2,513,115	2,948,881	2,948,881	2,948,881
Costs			**NPV**															
Gas costs	$		-															
Retail/Mixed use			-432,131	-4,487	-9,520	-15,150	-21,431	-28,420	-30,151	-31,987	-33,935	-36,001	-38,194	-40,520	-42,987	-87,385	-92,706	-98,352
Apartment/Condo-High Density			-920,102	-2,607	-5,531	-8,802	-12,450	-16,511	-17,516	-27,769	-39,205	-51,932	-66,063	-89,214	-102,594	-257,014	-272,666	-289,272
Official/Institutional			-145,797	-	-	-	-	-	-	-1,618	-3,433	-5,463	-7,728	-12,521	-15,693	-46,600	-49,438	-52,449
Civic			-49,691	-	-	-	-717	-1,521	-2,420	-3,423	-4,539	-4,816	-5,109	-5,420	-5,750	-11,689	-12,400	-13,156
Apartment/Condo-Medium Density			-2,076,505	-2,524	-5,356	-8,522	-27,362	-48,465	-68,645	-95,825	-126,061	-139,054	-153,161	-186,912	-217,860	-562,178	-596,415	-632,736
Apartment/Condo-Low Density			-984,749	-	-	-	-14,202	-30,134	-47,954	-67,832	-89,954	-95,432	-101,244	-107,409	-113,951	-231,638	-245,745	-260,711
O&M, fixed, heating, cooling	$		-287,527	-3,800	-3,914	-4,031	-15,517	-15,982	-16,462	-22,687	-23,368	-24,069	-24,791	-34,673	-35,713	-50,919	-52,446	-54,019
Electricity for chillers	$		-6,222,699	-51,915	-56,627	-61,767	-184,742	-201,511	-219,802	-311,367	-339,630	-370,458	-404,085	-582,500	-635,374	-1,802,302	-1,965,897	-2,144,342
Administration etc.	$		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sum	$		-11,119,200	-65,332	-80,948	-98,273	-276,421	-342,543	-402,949	-562,508	-660,125	-727,225	-800,374	-1,059,169	-1,169,922	-3,049,725	-3,287,714	-3,545,037
Total Investments			**NPV**															
Network cost	$		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Units costs, chillers			-7,535,698	-1,992,071	-	-	-4,191,577	-	-	-2,011,791	-	-	-	-2,796,943	-	-	-	-
Unit costs, gas boiler,	$		-1,056,622	-249,763	-	-	-631,415	-	-	-273,669	-	-	-	-391,576	-	-	-	-
Total investment	$		-8,592,320	-2,241,834	-	-	-4,822,991	-	-	-2,285,459	-	-	-	-3,188,519	-	-	-	-
Simple Cash Flow and payback			**NPV**															
Income	$		19,711,519	116,308	232,616	348,924	690,285	1,031,646	1,256,700	1,584,913	1,913,126	2,016,286	2,119,445	2,367,860	2,513,115	2,948,881	2,948,881	2,948,881
Costs	$		-11,119,200	-65,332	-80,948	-98,273	-276,421	-342,543	-402,949	-562,508	-660,125	-727,225	-800,374	-1,059,169	-1,169,922	-3,049,725	-3,287,714	-3,545,037
Investment	$		-8,592,320	-2,241,834	-	-	-4,822,991	-	-	-2,285,459	-	-	-	-3,188,519	-	-	-	-
Cash Flow	$		-0	-2,190,858	151,668	250,651	-4,409,127	689,103	853,751	-1,263,054	1,253,001	1,289,061	1,319,071	-1,879,828	1,343,193	-100,843	-338,833	-596,156
Accumulated Cash flow		**IRR**	**7.30%**	-2,190,858	-2,039,190	-1,788,540	-6,197,667	-5,508,564	-4,654,813	-5,917,867	-4,664,866	-3,375,806	-2,056,735	-3,936,562	-2,593,369	7,319,853	6,981,020	6,384,865
Discounted Cash flow (NPV)	$	7.3%	**-0**	-2,190,858	141,349	217,705	-3,569,057	519,859	600,251	-827,606	765,162	733,628	699,634	-929,225	618,787	-19,946	-62,459	-102,416
Accumulated Discounted Cash flow	$	7.3%		-2,190,858	-2,049,509	-1,831,803	-5,400,860	-4,881,001	-4,280,751	-5,108,357	-4,343,195	-3,609,568	-2,909,934	-3,839,159	-3,220,372	164,874	102,416	-0

8.3 Concept 1 – DHC

Cashflow DHC																		
			Sequence	0	1	2	3	4	5	6	7	8	9	10	11	23	24	25
	unit	Base	Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2042	2043	2044
		3%	price index	1,00	1,03	1,06	1,09	1,13	1,16	1,19	1,23	1,27	1,30	1,34	1,38	1,97	2,03	2,09
Income			**NPV**															
Heat Sales	$		5.740.991	28.543	57.157	85.772	186.545	287.318	359.548	463.053	566.558	597.904	629.250	705.346	750.167	885.270	885.341	885.412
Cooling sales	$		13.803.740	88.064	176.423	264.782	506.553	748.325	902.032	1.127.867	1.353.703	1.426.126	1.498.549	1.671.818	1.772.959	2.079.034	2.079.329	2.079.624
Capacity charge, heating	$		5.769.303	4.460	9.188	14.195	53.381	75.667	87.468	139.723	155.042	160.741	166.642	243.232	250.529	357.194	367.910	378.947
Capacity charge, cooling	$		4.638.722	4.326	8.911	13.768	44.466	62.566	71.743	111.719	124.035	129.014	134.179	195.169	201.024	286.612	295.210	304.067
Account charge, heating	$		430.088	360	742	1.146	4.799	6.726	7.679	10.575	11.866	12.404	12.964	17.901	18.438	26.288	27.077	27.889
Account charge, cooling	$		435.945	360	742	1.146	6.687	8.671	9.015	11.262	11.866	12.404	12.964	17.901	18.438	26.288	27.077	27.889
Account charge, electricity	$		430.088	360	742	1.146	4.799	6.726	7.679	10.575	11.866	12.404	12.964	17.901	18.438	26.288	27.077	27.889
Connection fee, heating	$		2.380.996	249.763	-	-	851.703	-	-	490.162	-	-	-	789.368	-	-	-	-
Connection fee, cooling	$		3.061.013	389.332	-	-	1.039.509	-	-	630.812	-	-	-	1.001.360	-	-	-	-
Sum	$		57.294.783	116.607	233.581	350.554	693.098	1.035.642	1.261.579	1.590.920	1.920.260	2.024.030	2.127.799	2.377.164	2.523.126	2.964.304	2.964.670	2.965.036
Costs			**NPV**															
Network operation costs	$		-235.434	-412	-866	-1.397	-3.112	-5.104	-6.835	-9.469	-12.496	-14.328	-16.385	-19.961	-23.056	-74.275	-80.787	-87.871
Admin, network	$		-118	-0	-0	-1	-2	-3	-3	-5	-6	-7	-8	-10	-12	-37	-40	-44
Maintenance network	$		-235	-0	-1	-1	-3	-5	-7	-9	-12	-14	-16	-20	-23	-74	-81	-88
Fixed demand charge, power	$		-602	-2	-5	-7	-15	-24	-30	-39	-49	-53	-58	-67	-73	-122	-126	-130
O&M heat pumps	$		-32.675	-855	-880	-907	-1.868	-1.924	-2.972	-3.061	-3.153	-3.248	-3.345	-3.446	-3.549	-5.060	-5.212	-5.368
O&M natural gas boilers	$		-5.274	-350	-361	-371	-382	-394	-406	-418	-430	-443	-457	-470	-484	-691	-711	-733
O&M chillers	$		-65.570	-2.743	-2.825	-2.910	-4.141	-4.265	-5.606	-5.774	-5.947	-6.126	-6.309	-6.499	-6.694	-9.544	-9.830	-10.125
Service and maintenance the	$		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Service and maintenance col	$		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy costs, electrcity proce	$		-2.417.782	-4.251	-9.196	-14.923	-33.267	-54.552	-72.842	-100.469	-132.211	-151.044	-172.116	-208.698	-240.277	-746.570	-809.926	-878.718
Energy costs, gas for gas boile	$		-3.830	-184	-195	-207	-219	-233	-247	-262	-278	-295	-313	-332	-352	-715	-759	-805
Reduction of building space	$		2.278.335	400.000	-	-	1.486.109	-	-	573.145	-	-	-	967.620	-	-	-	-
Sum	$		-2.761.519	-8.797	-14.329	-20.724	-43.010	-66.502	-88.948	-119.507	-154.583	-175.558	-199.008	-239.502	-274.519	-837.089	-907.472	-983.881
Total Investments			**NPV**															
Network cost	$		-10.034.441	-6.315.152	-	-	-2.107.768	-	-	-2.120.342	-	-	-	-2.815.487	-	-	-	-
Connection cost, substation	$		-3.073.017	-639.095	-	-	-1.730.727	-	-	-938.798	-	-	-	-1.332.470	-	-	-	-
Heat pumps	$		-1.994.906	-854.612	-	-	-854.612	-	-854.612	-	-	-	-	-	-	-	-	-
Natural gas boiler	$		-651.769	-700.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar thermal	$		-1.833.101	-1.968.750	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ATES	$		-931.099	-1.000.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermal storage	$		-111.732	-120.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chiller	$		-4.022.192	-2.743.028	-	-	-1.046.308	-	-1.046.308	-	-	-	-	-	-	-	-	-
Cold storage	$		-321.229	-345.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total investment	$		-22.973.484	-14.685.638	-	-	-5.739.415	-	-1.900.920	-3.059.140	-	-	-	-4.147.957	-	-	-	-
Simple Cash Flow and payback			**NPV**															
Income	$		19.544.731	116.607	233.581	350.554	693.098	1.035.642	1.261.579	1.590.920	1.920.260	2.024.030	2.127.799	2.377.164	2.523.126	2.964.304	2.964.670	2.965.036
Costs	$		-2.761.519	-8.797	-14.329	-20.724	-43.010	-66.502	-88.948	-119.507	-154.583	-175.558	-199.008	-239.502	-274.519	-837.089	-907.472	-983.881
Investment	$		-22.973.484	-14.685.638	-	-	-5.739.415	-	-1.900.920	-3.059.140	-	-	-	-4.147.957	-	-	-	-
Cash Flow	$		-6.190.273	-14.577.827	219.251	329.830	-5.089.327	969.140	-728.289	-1.587.728	1.765.677	1.848.472	1.928.791	-2.010.294	2.248.607	2.127.215	2.057.198	1.981.154
Accumulated Cash flow		**IRR**	**4,22%**	-14.577.827	-14.358.576	-14.028.746	-19.118.073	-18.148.933	-18.877.222	-20.464.950	-18.699.273	-16.850.801	-14.922.010	-16.932.305	-14.683.697	13.767.120	15.824.317	17.805.472
Discounted Cash flow (NPV)	$	7,4%	**-6.190.273**	-14.577.827	204.145	285.944	-4.108.162	728.399	-509.662	-1.034.547	1.071.227	1.044.188	1.014.487	-984.503	1.025.337	411.825	370.829	332.515
Accumulated Discounted Cas	$	7,4%		-14.577.827	-14.373.682	-14.087.738	-18.195.900	-17.467.501	-17.977.163	-19.011.710	-17.940.484	-16.896.296	-15.881.809	-16.866.311	-15.840.975	-7.351.697	-6.980.868	-6.648.353

8.4 Concept 2 – IND

Cashflow IND																			
			Sequence	0	1	2	3	4	5	6	7	8	9	10	11	12	23	24	25
	unit	Base	Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2042	2043	2044
		3%	price index	1.00	1.03	1.06	1.09	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.97	2.03	2.09
Income			**NPV**																
Heating	$		5,816,513	28,548	57,168	85,787	186,579	287,370	359,613	463,137	566,661	598,013	629,365	705,475	750,304	795,133	885,431	885,503	885,574
Cooling	$		13,933,681	87,772	175,838	263,903	504,872	745,841	899,038	1,124,124	1,349,210	1,421,393	1,493,576	1,666,270	1,767,075	1,867,881	2,072,135	2,072,428	2,072,722
Sum	$		19,750,193	116,320	233,006	349,691	691,451	1,033,211	1,258,652	1,587,261	1,915,871	2,019,406	2,122,941	2,371,745	2,517,380	2,663,014	2,957,566	2,957,931	2,958,296
Costs			**NPV**																
O&M Heat pump + oil burner	$		-374,544	-4,490	-4,625	-4,763	-21,588	-22,236	-22,903	-30,023	-30,924	-31,852	-32,807	-44,653	-45,993	-47,372	-65,574	-67,542	-69,568
O&M Chiller	$		-125,126	-1,500	-1,545	-1,591	-7,212	-7,428	-7,651	-10,030	-10,331	-10,641	-10,960	-14,917	-15,365	-15,826	-21,907	-22,564	-23,241
Electricity	$		-4,281,729	-20,164	-21,995	-23,991	-110,111	-120,106	-131,008	-219,501	-239,425	-261,157	-284,863	-409,203	-446,347	-486,862	-1,266,108	-1,381,032	-1,506,389
Energy cost, Oil	$		-319,136	-686	-1,456	-2,317	-5,349	-8,741	-11,604	-15,856	-20,583	-23,043	-25,726	-30,594	-34,518	-38,807	-82,739	-87,778	-93,123
Sum	$		-5,100,535	-26,841	-29,620	-32,663	-144,260	-158,511	-173,166	-275,410	-301,263	-326,693	-354,356	-499,368	-542,223	-588,867	-1,436,328	-1,558,915	-1,692,321
Total Investments			**NPV**																
Heat pumps	$		-2,641,554	-624,407	-	-	-1,578,537	-	-	-684,172	-	-	-	-978,940	-	-	-	-	-
Boreholes	$		-3,794,213	-750,000	-	-	-2,550,000	-	-	-900,000	-	-	-	-1,350,000	-	-	-	-	-
Oil burner	$		-271,969	-53,760	-	-	-182,784	-	-	-64,512	-	-	-	-96,768	-	-	-	-	-
Chillers	$		-10,503,386	-2,480,325	-	-	-6,514,268	-	-	-2,574,826	-	-	-	-3,701,229	-	-	-	-	-
Solar PV	$		-3,227,581	-968,960	-	-	-1,846,263	-	-	-643,879	-	-	-	-1,168,980	-	-	-	-	-
Total investment	$		-20,438,702	-4,877,453	-	-	-12,671,851	-	-	-4,867,388	-	-	-	-7,295,917	-	-	-	-	-
Simple Cash Flow and payback			**NPV**																
Income	$		19,750,193	116,320	233,006	349,691	691,451	1,033,211	1,258,652	1,587,261	1,915,871	2,019,406	2,122,941	2,371,745	2,517,380	2,663,014	2,957,566	2,957,931	2,958,296
Costs	$		-5,100,535	-26,841	-29,620	-32,663	-144,260	-158,511	-173,166	-275,410	-301,263	-326,693	-354,356	-499,368	-542,223	-588,867	-1,436,328	-1,558,915	-1,692,321
Investment	$		-20,438,702	-4,877,453	-	-	-12,671,851	-	-	-4,867,388	-	-	-	-7,295,917	-	-	-	-	-
Cash Flow	$		-5,789,044	-4,787,973	203,385	317,028	-12,124,660	874,701	1,085,485	-3,555,537	1,614,609	1,692,713	1,768,585	-5,423,539	1,975,157	2,074,147	1,521,239	1,399,016	1,265,975
Accumulated Cash flow		**IRR**	**3.13%**	-4,787,973	-4,584,588	-4,267,560	-16,392,220	-15,517,519	-14,432,034	-17,987,571	-16,372,962	-14,680,249	-12,911,664	-18,335,204	-16,360,047	-14,285,900	7,197,397	8,596,413	9,862,388
Discounted Cash flow (NPV)	$	7.3%	**-5,789,044**	-4,787,973	189,548	275,358	-9,814,550	659,873	763,177	-2,329,737	985,983	963,353	938,055	-2,680,931	909,923	890,518	300,887	257,887	217,486
Accumulated Discounted Cash flo	$	7.3%		-4,787,973	-4,598,425	-4,323,067	-14,137,617	-13,477,744	-12,714,567	-15,044,303	-14,058,321	-13,094,967	-12,156,912	-14,837,843	-13,927,920	-13,037,402	-6,687,018	-6,429,131	-6,211,644