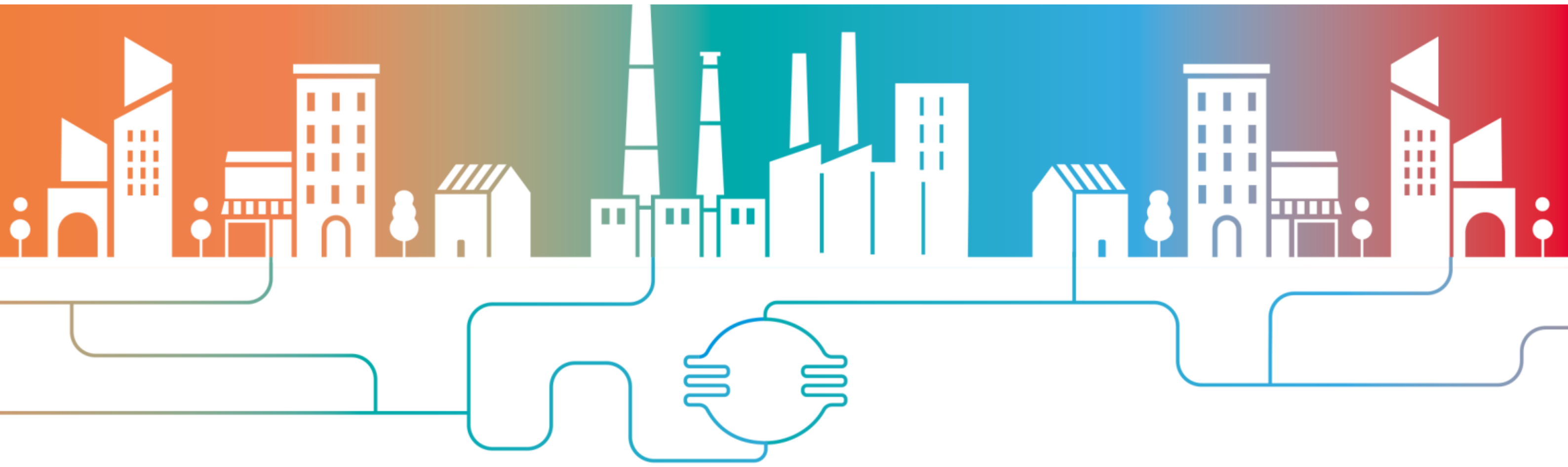
Report on the trading schemes elaborated – Action C.5.1



Low temperature, urban waste heat into district heating and cooling networks

as a clean source of thermal energy

LIFE4HeatRecovery

Project Title: Low temperature, urban waste heat into district heating and cooling networks as a clean source of thermal energy

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Table of Contents

1 Introduction

In the previous research and innovation projects carried out by the partners of the LIFE4HeatRecovery project, several business models on smart thermal energy systems – including waste heat recovery into district heating networks – have been described in a quantitative and qualitative way. The aim of this report is to examine the legislative and regulatory framework in relation to the business models considered, in order to identify their compatibility with the current scenario, highlight any critical aspects, and suggest possible solutions. Moreover, the economic models for the sustainability of such waste heat recovery initiatives will be considered. This analysis will be carried out in relation to the 3 demo cases of the LIFE4HeatRecovery project, namely the Italian case located in Ospitaletto (heat recovery from the ASO foundry into the district heating network of Cogeme), the Dutch case located in Heerlen (heat recovery from the VDL foundry into the district heating network of Mijnwater), and the Danish case located in Aalborg (heat recovery from Aalborg University data centre into the district heating network of Aalborg Forsyning).

2 Italian case

The purpose of this chapter is to examine the legislation, regulation and economic variables to be taken into account for the construction of a business model in Italy. A real example will be presented, referring to the demo of Ospitaletto.

2.1 Legislative issues

2.1.1 Heat transfer

In the traditional model, a user exploits a source of energy (electricity, gas, coal or other liquid or solid combustible) to power a heating system that produces the amount necessary to meet requirements. From 1800 onwards, Italian legislation has evolved in accordance with this traditional model, first in relation to excise taxes, then VAT, and more recently in a regulatory context. In fact, from the end of the 1960s until the beginning of this century, managing public services was the prerogative of monopolist government departments. With the markets opening up and the arrival of new technologies and services, it became necessary to further regulate the sector, and this is not yet complete with regard to heating.

The relationships are clearly defined in the traditional model for managing heating requirements, which in Italy involves a service that powers a boiler via natural gas, which in turn provides the heat required for a domestic water supply and heating.

The local Distributor supplies consumers with natural gas under a contract with a Vendor, who collects VAT and acts as a withholding agent for excise purposes. Consumers are responsible for operating and maintaining their heating systems in accordance with legislation and rules of good practice. Distribution and sales activities are regulated by specific rules, in line with tax legislation.

Understanding the traditional model is essential for understanding the business model, as it represents the benchmark, the baseline solution that any alternative must match at an economic level.

The widespread use of district heating systems, initially at high temperature to produce domestic water heating and heating only, now with various technological solutions and even district cooling services, in addition to even more technologically advanced solutions directed at companies in the future, sets new challenges with regard to regulation, which is partially lacking.

From a legal viewpoint, there is no clear classification of district heating, which does not purely constitute heat transfer nor a straightforward service, even if in principle it is more akin to the latter.

The only reference standards currently in force are Presidential Decree no. 412 of 26 August 1993, and Legislative Decree no. 115 of 30 May 2008, which only address some aspects of the issue, given that they target the subject of saving energy.

With regard to our case, Presidential Decree 412/93 (and subsequent amendments) defines what is a heating system and sets out the requirements and obligations of the owner of the system. In particular, a heating system is defined as "a technological system designed to heat and cool rooms with or without the production of domestic water heating or designed for the centralized production of domestic water heating only, including heat production, distribution and use systems...". Owners of the heating system may manage it themselves or outsource its management to a "third party responsible for the operation and maintenance of the heating system", through an "energy service contract".

The fundamental discriminating factor is therefore the definition of the heating system and its ownership, to establish whether or not it is subject to the requirements set out in Presidential Decree 412/93, and if so the compulsory types of contracts required by legislation.

The energy service contract was long awaited by operators and was finally regulated solely with the Legislative Decree of 30 May 2008. It concerns a particular type of contract however, directed at energy efficiency targets, which requires service providers to meet a set of obligations, therefore it must be used effectively and only within specific relationships.

If the heating system is owned and managed directly by the user, only the heat transfer from the network to the system is classified as a service, but it is not subject to the requirements of Presidential Decree 412/93.

2.1.2 Energy and network regulation

In Italy, ARERA (Autorità di Regolazione per Energia Reti e Ambiente) is the regulatory body that oversees the framework on tariffs, the market and service access in various sectors - the production, distribution and sale of electricity and gas, integrated water services, district heating networks, and environmental services.

ARERA was set up on 14/11/1995 as the electricity and gas authority AEEG, and gradually saw its scope of responsibilities include other areas. Its decisions apply to all products and services in this analysis, therefore it is important to recognize its role.

The regulation of district heating networks is fairly recent, resulting from legislative decree no. 102 of 04/07/2014, but it is currently limited to the definition of criteria and cost of connecting consumers, quality and service continuity, monitoring, and in some cases tariff regulation.

At the moment, district heating services are not regulated in the same way as other networks, such as electricity or gas distribution, where proceeds and profit are strictly regulated. However, it cannot be excluded that the authority will have a wider scope of responsibilities in the near future.

2.2 Energy Market

2.2.1 Electricity Market

In Italy, the Ministry of Economic Development promotes the development of wholesale and retail electricity markets. The liberalization of the electricity sector started in Italy in 1999 led to the birth of the so-called electricity market, that is, the seat where now the transactions related to the wholesale sale of electricity take place.

The definition of the "electricity market" refers to the location of transactions involving the wholesale trading of electricity in Italy. On a more practical level, it is a telematic marketplace where electricity wholesale trading takes place and where the price of energy itself is the result of the meeting between its demand and the quantity offered by operators.

The electricity market in Italy was born as a result of the so-called "Bersani Decree" (i.e. Legislative Decree No 79 of 16 March 1999).

The management of the Italian electricity market is entrusted to the “Gestore dei Mercati Energetici” (GME), a company controlled by the “Gestore dei Servizi Energetici” (GSE).

The Italian electricity market is divided, on a temporal basis:

- Spot Market (MPE): short-term market;
- Forward market (MTE): long-term market.

The spot price is the reference price of supply contracts indexed to PUN (Prezzo Unico Nazionale: average of the zonal prices of the Spot Market weighted with total purchases, net of purchases of pumping and foreign areas).

The prices "futures" or "forward", concern the products with a delivery period further in time (different from "today" or "tomorrow") and that therefore can, before the beginning of the delivery, be traded several times. Forward prices are an image of the expectation that operators have for spot prices over the period considered, so they are a forecast of the average price of the PUN in a given future. "Future/forward" prices are used as a reference for gas and electricity supply offers at a fixed price.

2.2.2 Gas Market

In 2010, the gas exchange in Italy was launched, managed by the GME where bids for purchase and sale take place. In the power exchanges operate most of the Italian suppliers who belong to the Free Market to buy wholesale gas and energy.

GME only manages the platforms where trading, contract management, payments and billing take place and is in the hands of operators who sell and purchase natural gas.

The entities authorized to operate on the regulated market of PSV capacities (Virtual Exchange Point: electronic platform that allows the meeting between supply and demand of the gas market in Italy. The price of gas is defined here) have access to trading platforms for the purchase of natural gas. The PSV is therefore an electronic system for the exchange of natural gas and the transfer of gas transmission capacity in the network.

As for electricity, the gas market is also structured on a temporal basis:

- Spot gas market (MPGAS): short-term trading;
- Forward market (MT-GAS): exchanges with longer time horizons than the spot market;

The spot price is the reference price of supply contracts indexed to PSV.

The prices "futures" or "forward", on the other hand, concern the products with a delivery period further in time (different from "today" or "tomorrow") and that therefore can, before the beginning of the delivery be traded several times. Forward prices are an image of the expectation that operators have for spot prices over the period considered, so they are a forecast of the average price of the PSV in a given future. "Future/forward" prices are used as a reference for gas and electricity supply offers at a fixed price.

2.3 Tax issues

A discussion on the main tax considerations that affect the business model follows. What we considered below are based on the current situation for the 2023 tax year.

2.3.1 Excise taxes

Excise taxes are applied indirectly (i.e. are not linked to the income of the party required to pay them) to the consumption of particular items. They represent one of the oldest forms of taxation and are therefore applied very disparately in EU countries.

The European Council initiated a harmonization procedure with Directive 2003/96/EC, which does however leave considerable room for the principle of subsidiarity in relation to the methods of applying this type of tax throughout EU territory, which differ significantly from one country to another. The key principle of the tax is shared however - the tax is generated when certain types of consumer goods are produced or imported in EU territory, whereas the liability for the tax charge occurs when the supply/use of the goods takes place and depends on the country where this happens.

Unlike VAT and customs duties, which are also indirect taxes, in Italy excise taxes are not linked to the value of goods, but are an addition to the value, and therefore constitute a taxable amount for VAT purposes. This is an extensively debated topic however, due to disagreement between various judgements by Italy's Supreme Court and the EU framework.

The main products subject to excise taxes are alcohol, tobacco, fuel and electricity. Excise regulations are defined in a consolidated excise bill (i.e. legislative decree no. 504 of 26 October 1995 and subsequent amendments). Excise tax on the consumption of electricity and natural gas are of particular importance for the purpose of this analysis.

With regard to electricity, the party liable to pay the tax is usually the vendor (releases the electricity for consumption), except in the case where the consumer is also a self-producer. In this case, the self-producer holds the Electricity Generation License, and must provide annual communication, which forms the basis for calculating the excise tax.

Excise tax differs considerably in relation to type of consumption, domestic or industrial, and in the second case on the basis of consumption brackets (the rate is fixed over a certain monthly consumption). There are also various exemptions, especially for self-consumed electricity produced from renewable sources, in addition to energy consumption where the cost of the energy represents more than 50% of the final cost.

With regard to natural gas, its use for domestic or industrial purposes is subject to excise tax - for industrial use equivalent to 0.012498€/m3 and for domestic use in line with a gradual scale of consumption up to 0.1733074 €/m3.

In this case too, there are exemptions and reliefs, especially for the production of electricity, with additional relief in the case of self-production.

For the purposes of our analysis, the methane used to supply a cogeneration system that powers a district heating network is subject to excise, calculated by applying a flat-rate method to determine the amount relating to electricity production and the amount relating to heat production. The gas used to produce heat is therefore taxed on the basis of intended use (domestic or industrial). However, where the relationship between the electricity produced and the heat energy supplied to the network is greater than 10%, industrial excise tax is still applied to the amount relating to heat production.

Finally, it should be noted that supplying heat via a heat-transfer fluid is not considered an operation subject to excise.

2.3.2 Value Added Tax (VAT)

VAT was introduced in Italy with Presidential Decree no. 633 of 26 October 1972, following a European Community tax harmonization process defined with Directive 62/228/EEC. As with excise tax, VAT is an indirect tax paid by final consumers. As always, the application of Directive 62/228/EEC was disparate in the European landscape, therefore it varies significantly from country to country and from year to year, in line with the dynamics and needs of public budgets.

For companies, barring specific consumption which is only partially tax deductible, VAT constitutes a transactional tax, which is therefore only paid by the final consumer. Indeed, in the value chain, every company collects VAT from customers and pays VAT to suppliers - the balance is paid to the government. Only the final user has no way of deducting VAT.

In 2023, standard VAT in Italy is 22%, and tax relief rates of 4% and 10% are available for specific categories of goods.

The supply of energy, fuel and heat falls within the scope of VAT.

The sale of natural gas is taxed at standard rate but with some partial exemptions. Domestic supplies within an annual consumption of 480 m^3, the consumption of mining companies, manufacturers, printing companies, farms, and electricity producers pay a rate of 10%.

The supply of electricity is also taxed at standard rate, except for some categories where a reduced rate of 10% applies - mining companies, manufacturers, printing companies, farms, redevelopment organizations and wholesale customers.

Supplying heat falls within the scope of standard VAT. There is however a tax relief rate of 10% for heat for domestic users supplied through public district heating networks, energy service contracts, and produced from renewable sources or high-efficiency CHP systems.

This relief, irrelevant for industrial supplies where full tax deduction makes the rate applied unimportant, is significant in the domestic context, as in the case of domestic heating consumption the threshold at which the relief rate applies is often exceeded. In this case, the application of the reduced rate is advantageous.

In 2021, as a result of the increase in energy costs, in Italy with Decree-Law 27 September 2021 n. 31, the reduction to 5% of the VAT rate applicable to gas supplies for civil and industrial uses was introduced. This reform is temporary.

2.3.3 Corporation Tax (IRES)

IRES is the main direct tax on business activities and is fixed at a rate of 24%. It is applied to proceeds net of deductible costs. Not all costs are actually deductible and many not completely. It is impossible to explore the complexity of Italian taxation in this short report, therefore all costs will be presumed deductible for the purpose of this project.

2.3.4 Regional Business Tax (IRAP)

IRAP is the second direct business tax on corporate proceeds and differs considerably from IRES due to the basis for calculation and the taxable amount. The rate of at least 3.9% is established at a regional level (regional government departments are the beneficiaries of this tax) and differs on the basis of the business activities involved.

The taxable base is also a complex calculation and generally corresponds to operating income, although many costs are not deductible. For example, up until 2016 the cost of labour was not deductible, and presently it is limited to employees with a permanent contract. Amounts relating to interest on financing agreements or finance leases are currently deductible.

For the purposes of this analysis, we will consider the minimum rate of 3.9% and the full deductibility of operating costs. The analysis carried out is unlevered, therefore the tax impact on debt interest is not relevant.

2.4 Incentives

A discussion on the main incentives considerations that affect the business model follows. What we considered below are based on the current situation for the 2022 tax year.

2.4.1 VAT cut on district heating supply

With the Budget Law 2023, the government extended the reduced 5% VAT applied to gas supply to the supply of district heating services as well, for both civil and industrial use. The rule was initially planned only for the first quarter of the year 2023, and later extended to the second quarter by Law 56/2023. The intention to extend this bonus is not clear, as well as the will to make this reduction structural in the legal system.

2.4.2 Titoli di Efficienza Energetica (TEE)

The provisions relating to energy efficiency came into force in Italy with Legislative Decree 79/1999, which implemented Directive 96/92/EC and provides, among other things, the mandatory requirement for energy distributors to adopt efficiency measures in the final uses of energy. The law has been revised over the years and the current wording is the one adopted with Ministerial decree of 11 January 2017, as amended with the provisions of Ministerial Decree of 21 May 2021.

The incentive policy aimed at obtaining energy savings contemplates the issuance of *Certificati bianchi* (literally 'White Certificates', or *TEE – Titoli di Efficienza Energetica*, literally 'Energy Efficiency Credits'), each worthing 1 TOE - tonne of oil equivalent saved.

The incentive programme covers new installations or replacements in different categories of interventions, each associated with the duration of the incentive.

The interventions fall into the Standardized Project or Final Project categories: in the former case, there are extremely clear guidelines on how to calculate the savings, while in the latter case, the applicant is required to develop a system for measuring the situation ex ante and ex post in order to provide evidence of the savings achieved. The Standardized Projects are actually applicable to a very limited number of cases and therefore all the complex projects fall within the final case study. Below an example of the final projects, adapted to the Italian case, which include the installation and/or replacement operations reported in the following table.

Table 1 – Type of project (TEE[1])

Type of project	Service life – New installation [Year]	Service life – Replacement [Year]	Service life – integrated efficiency [Year]
Thermal or refrigerating energy production plants serving district heating and/or cooling networks.	10	7	5
Connection of new users to efficient district heating and/or cooling networks	5	-	-

To be eligible, the final projects must demonstrate a saving of no less than 10 TOE (at least in the first year of operation). The savings are calculated on the primary energy consumption in the ex-ante situation for projects relating to existing installations and on a reference consumption for new installations.

TEE can be recognized according to the types of intervention:

- Type I, certifying the achievement of primary energy savings through measures implemented to reduce final electricity consumption;
- Type II, certifying the achievement of primary energy savings through projects reducing natural-gas consumption;
- Type III, certifying the achievement of savings of forms of primary energy other than electricity and natural gas and not used for transport;
- Type IV, certifying the achievement of savings of forms of primary energy other than electricity and gas in the transport sector.

The incentive mechanism is based on a mandatory energy saving scheme for all electricity and natural gas distributors with more than 50 thousand end-customers. White certificates can then be obtained through such energy efficiency projects, but also be traded on regulated markets.

Below the evolution of TEE prices in recent years.

[1] https://www.gse.it/servizi-per-te/efficienza-energetica/certificati-bianchi/documenti

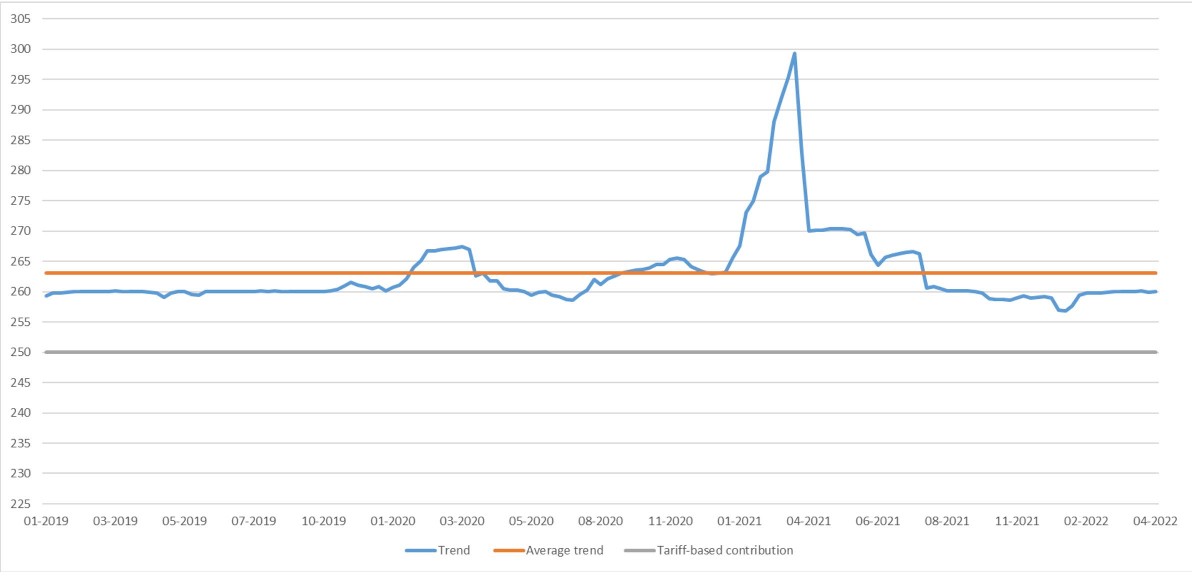


Figure 1 – TEE Prices

The recognition of White Certificates cannot be combined with other forms of incentives for electricity or gas tariffs or other forms of government aid for the same projects.

On May 3, 2022, the Operational Guide referred to in Article 15, paragraph 1, of the DM White Certificates, was approved to promote the identification, definition and presentation of projects within the mechanism of the TEE. Annex 5 of the Operational Guide, called "Project Fact Sheets", defines for some interventions project cards containing:

a) the list of eligibility conditions to be met, including any regulatory constraints;

b) the list of documentation to be submitted to the GSE[2];

c) the list of the minimum documentation to be kept in case of checks by the GSE;

d) in the case of new projects, where possible, the reference consumption value;

e) in the case of substitution interventions, the procedures for the definition of consumption prior to the implementation of the project;

f) the algorithm for calculating savings.

The project summary n. 8 - "Connection of new users to efficient district heating networks" provides all the useful information to estimate the TEE that can be obtained from the connection of new users to district heating networks. To date, there is no project sheet dedicated to the installation and/or replacement of "Thermal or refrigerating energy production systems serving district heating and/or cooling networks". The estimate of the TEE obtainable from this last intervention will be calculated as

[2] GSE: Gestore dei Servizi energetici

the product between the primary thermal energy (in MWh_t) saved between the situation before and after intervention and a conversion factor f_t equal to 0.086 $\frac{toe}{MWh_t}$.

2.4.3 Conto Termico Scheme

Ministerial Decree of 16 February 2016 set out incentives to increase energy efficiency and to produce energy from renewable sources for small systems implemented in existing buildings. The incentive differs depending on the type of work carried out and various types are included.

Of interest to the project is category 2.A - Replacement of existing winter heating systems with heat pumps with power level lower than 2000 thermal kW. Operations must be implemented directly by the owner of the building (or party with a legal right), who can also obtain support from an energy service company (ESCo) through an energy service contract.

For category 2.A, the incentive is calculated by considering a set of parameters that can be obtained from official government tables:

- the power of the system;
- annual hours of operation;
- the COP;
- a value coefficient.

The incentive is recognized for 2 years on systems lower than 35 kW and 5 years on larger systems.

For the purposes of our project, considering that the investment is forecast as the responsibility of the utility company and the main aim of the skid is the production of heat for the network, this incentive does not appear to be applicable, but it remains of interest for networks in general where the user incurs the cost of connection and therefore the heat pump.

2.4.4 One-time tax credit

The rule stipulates that the contribution, amounting to 20.66 euros per kW of committed power, will be transferred to the end user in the form of a tax credit, favouring the party to whom the cost of grid connection is due.

2.5 Economic variables

Other economic variables are listed below.

2.5.1 Tax Credit

This additional tax relief mechanism was stipulated in Act no. 448 of 23 December 1998, amended by Act no. 203 of 22 December 2008 and subsequent amendments.

In particular, there is currently a tax credit of 21.95 €/MWh for heat provided to consumers from district heating networks supplied with biomass or geothermal energy, in districts that come under climatic zones E and F. This credit must be transferred to the sale price to the final user.

Applying this mechanism is so complex that clarification from the Italian Inland Revenue was required on certain geothermal aspects, resulting in the issue of Resolution no. 416/E of 31 October 2008. This credit can only be applied to all heat provided that the temperature of the geothermal fluid is higher than 40°C before any increase via other systems, and the heat from the geothermal source generally prevails over heat produced with other systems.

The tax credit obtained in this way can be used to pay other tax obligations.

This mechanism aims to reduce the cost of the service for the final user and, although it does not contribute to the operator's profit directly, it helps to make the service provided by district heating competitive compared with autonomous heat production.

2.5.2 Emission Trading System for CO2 (ETS)

Directive 2003/87/EC (as last amended by EU Directive 2018/410) provides that, from 1 January 2005, large emitting plants in the European Union cannot operate without a permit for greenhouse gas emissions. Each authorized installation must offset its emissions annually with allowances (European Union Allowances - EUA, equivalent to 1 tonne of co2eq) that can be bought and sold by the individual operators concerned. Installations may purchase their shares in European public auctions or receive them free of charge. Alternatively, they can source from the market. These certificates can be marketed and are designed to cover the amount of pollutants released by the systems.

Below the price trend of CO2 quotas over the last few years:

Figure 2 - CO2 Price

2.5.3 Inflation

Here is the trend of HICP inflation in Italy over the last 30 years:

Figure 3 - Historical inflation Italy HICP (annual basis)

Harmonised inflation is based on the Harmonised Index of Consumer Prices (HICP) and is used to compare inflation figures from EU countries. Italy's average HICP inflation in the first quarter of 2022 is 6.08 %.

2.5.4 Weighted average cost of capital (WACC)

The Weighted Average Cost of Capital (WACC) is the weighted average cost of capital which enables an undertaking or investor to determine the cost of capital. The discounting of annual flows was carried out by considering a WACC equivalent to 5.5%.

2.6 Minimise the electric consumption of the heat pump

Energy saving policies, and thus the need to supplement thermal energy needs with renewable energy sources, has led to the increasing use of heat pumps.

The heat pump is capable of acquiring heat from a cold source (e.g., outside air) and then transferring it to a warmer temperature environment.

COP (coefficient of performance) is the ratio of heat output transferred to the hot source to electrical power input.

The electrical power consumption of a heat pump is particularly high in the winter season, especially when used in cold climates.

One of the first solutions to minimize the consumption of a heat pump is to choose a machine with an inverter rather than a traditional on/off one. In a heat pump with an inverter, energy consumption is optimized. After reaching the ideal temperature, the system attenuates its operation, but does not stop permanently. This means that a large amount of energy is not wasted with constant switching on and off. In contrast, a traditional heat pump with on/off operation stops its operation once the desired temperature is reached. Another way to reduce on/off cycles without the use of a modulating heat pump, is the inclusion of properly sized thermal storages.

Another viable option to be able to cope with the power consumption of a heat pump is to provide energy through a photovoltaic system. The self-consumption mechanism allows the photovoltaic system to be put to good use, and the energy produced would then be consumed on-site and not fed into the grid. From the point of view of electrical substations, sizing photovoltaics for heat pumps so as to maximize their self-consumption would allow them to relieve the national grid, balancing the energy demand, mitigating peak demand to be attributed to the heat pump itself, and reducing the phenomenon of grid imbalance due to the feed-in of electricity to the grid produced by the same photovoltaics.

2.7 Analysis of scenarios

Following the analysis carried out with reference to the regulatory/legislative framework, various economic scenarios taken into account for the construction of a business plan are analyzed below.

It is good to specify that the scenarios proposed have been used in reference to the demo of Ospitaletto, but are also adaptable to other realities similar to the one considered.

The scenarios considered take into account the different costs for the production of heat from geothermal systems or gas plants.

Below the scenarios considered:

- IT0: [null value for heat] baseline scenario. There are no cost savings associated with heat production for the network (i.e., the heat supplied to the network would be provided at 0 €/MWht and cost savings are considered only for the self-consumed heat) and no possibility of obtaining the tax credit. EECs are considered;
- ITmar: [marginal cost]. It is considered an existing system (geothermal plant) which has to produce only the incremental amount of heating required (i.e., the heat supplied to the network yields cost savings of 17 €/MWht). EECs are considered;

- ITavg: [average cost]. That is the cost related to build a new plant in order to provide the needed heat. It was computed as the average revenue to reach breakeven of the geothermal plant (i.e., the heat supplied to the network yields cost savings of 56 €/MWht). EECs are considered;
- ITind: [industrial cost]. The cost beared by an industrial client to obtain heat through gas (i.e., the heat supplied to the network yields cost savings of PSV+5 €/MWht). EECs are considered;
- IT0CI: [tax credit – null value for heat]. There are no cost savings associated with heat production for the network (i.e., the heat supplied to the network would be provided at 0 €/MWht) and possibility of obtaining the tax credit (21.95 €/MWht). EECs are considered;
- IT0FTV: [photovoltaic plant – null value for heat]. It was considered the installation of a photovoltaic system designed to minimize the purchase of electricity for the operation of the heat pump and maximize the self-consumption. EECs are considered.

Combined scenarios:

- ITmarCI: combination of ITmar e IT0CI;
- ITavgCI: combination of ITavg and IT0CI;
- ITindCI: combination of ITind and IT0CI;
- ITFTVmar: combination of IT0FTV and ITmar;
- ITFTVavg: combination of IT0FTV and ITavg;
- ITFTVind: combination of IT0FTV and ITind;
- ITFTVCI: combination of IT0FTV and IT0CI;
- ITFTVmarCI: combination of ITFTV, ITmar and IT0CI;
- ITFTVavgCI: combination of ITFTV, ITavg and IT0CI;
- ITFTVindCI: combination of ITFTV, ITind and IT0CI;

Business Plan – Reference to the project – Ospitaletto

In the business model considered, we will be assessing the overall return on investment in heat recovery, without making any distinction between the amount for the owner of the heat distribution network and the customer. Defining how to split any savings will subsequently be the subject of business negotiations.

The business plan was developed over a period of 20 years.

2.7.1 Technical hypotheses

To meet annual customer heating requirements, equivalent to 324 MWht, at the moment a primary energy amount of 439 MWht is consumed, resulting almost entirely from gas consumption and, to a lesser extent, the electricity required for boiler operation.

The project aims to assess an alternative, namely the recovery of waste heat and connection to a district heating network (DHN), therefore reducing the amount of primary energy used.

The waste heat is provided by the company ASO, which produces it for about 6000 h/year, equivalent to 24-hour production on weekdays for 50 weeks. Considering a peak capacity of 146 kW and self-consumption requirement for 180 MWht, this entails the recovery of waste heat for individual purposes for 1,231 hours. In the remaining 4,769 hours, the waste heat can be supplied to the DHN as energy equivalent to 696 MWht.

66 MWht would be drawn from the DHN, whereas primary energy consumption would drop to 204 MWht.

2.7.2 Excise Taxes

For the purpose of our analysis, at the moment the supply of heat via a heat-transfer fluid is not considered an operation subject to excise tax.

2.7.3 Value Added Tax (VAT)

It is considered the application of VAT equal to 10%.

2.7.4 Corporation Tax (IRES)

IRES is the main direct tax on business activities and is fixed at a rate of 24%.

2.7.5 Regional Business Tax (IRAP)

IRAP is fixed at rate of 3,9% in Lombardy.

2.7.6 Energy Efficiency Credits (EECs)

The value of EECs was considered the cap to the tariff contribution recognised, amounting to 250 €/EECs, introduced by the Ministerial Decree of 10 May 2018. For the project considered, the EECs would be available for 10 years.

2.7.7 Conto Termico Schemes

For the purposes of our project, considering that the investment is forecast as the responsibility of the utility company and the main aim of the skid is the production of heat for the network, this incentive does not appear to be applicable.

2.7.8 Tax Credit

A tax credit of 21.95 €/MWh was applied to all energy supplied to the user, by analogy with the geothermal case.

2.7.9 Emission Trading System for CO2

The ETS have not been taken into account for our case.

2.7.10 Inflation

Inflation has already been considered within the WACC.

2.7.11 WACC

The discounting of annual flows was carried out by considering a WACC equivalent to 5.5%.

2.7.12 Energy Price

For the Electricity Price for the year 2022 the value of the current PUN was taken into account, from 2023 to 2027 the future price was used and for the following years an average cost of 120 €/MWh was estimated until 2031 and 100 €/MWh until 2041.

For the Price of Gas for the year 2022 the value of the current PSV was taken into account, from 2023 to 2027 the future price was used and for the following years an average cost of 20 €/MWh was estimated until 2031 and 30 €/MWh until 2041.

2.7.13 Costs

Investments

All the investments were considered at the start of the period assessed, with the sole exception of special maintenance, which was presumed halfway through the lifetime of the system. Costs as similar to the demo case final values, with some differences introduced for a higher generality (the demo includes containers and platforms not needed in most cases).

Below the investments without photovoltaic plant:

Table 2 – Investments without PV system

	[€]
Skid (150 kW)	247,000
Installation & adaptation of the network	110,000
Connection to DHN	10,000
Connection to electricity network	3,000
Extraordinary maintenance (after 10 years)	75,000
TOT.	445,000 €

Below the investments with photovoltaic plant:

Table 3 – Investments with PV system

	[€]
Skid (150 kW)	247,000
Installation & adaptation of the network	143,000
Connection to DHN	10,000
Connection to electricity network	5,000
Extraordinary maintenance (after 10 years)	78,000
TOT.	483,000 €

Investment amounts have been overestimated as a precaution, and even though the lifetime of the skid is guaranteed for 15 years, we have presumed that significant special maintenance will be necessary in the 10th year.

Operating Costs

In addition to the initial investments there are also operating costs:

Table 4 – Operating costs without PV system

	[€]
O&M	40,000
Power for HP	274,000
Power for grid	53,500
TOT[3].	367,500

Table 5 – Operating costs with PV system

	[€]
O&M	40,000
O&M PV system	24,000
Power for HP	188,000
Power for grid	36,600
TOT[4].	288,000

2.7.14 Revenues

The structure of revenues has been broken down into different items concerning:

Table 6 - Revenues

	[€]
Revenues from heating supply	517,638
Revenues from energy efficiency certificates	50,534
Revenues from not using a waste heat cooling system	33,457

[3] 20- years costs [service life]
[4] 20- years costs [service life]

Specific revenues of scenario:

Table 7 – Specific revenues of scenario

	[€]
Tax credit	420,123
Revenue from electricity sold [PV system]	74,471
Costs avoided by heat production [marginal costs]	324,264
Costs avoided by heat production [average costs]	1,068,163
Costs avoided by heat production [industrial costs]	804,163

2.7.15 Results

The starting point for our analysis is represented by the scenario named IT0, where there are no cost savings associated with heat production (i.e. the heat would be provided at 0 €/MWht) and no possibility of obtaining the tax credit.

In this scenario, the Net Present Value (NPV), considering a useful life of 20 years is extremely negative, amounting to -207,590 € with an Internal Rate of Return (IRR) of -12.3%.

We can therefore state that, if the heat were available free of charge and the tax credit cannot be obtained, there are no economic reasons on which to base the investment.

The various scenarios are outlined below on the basis of VAN and IRR.

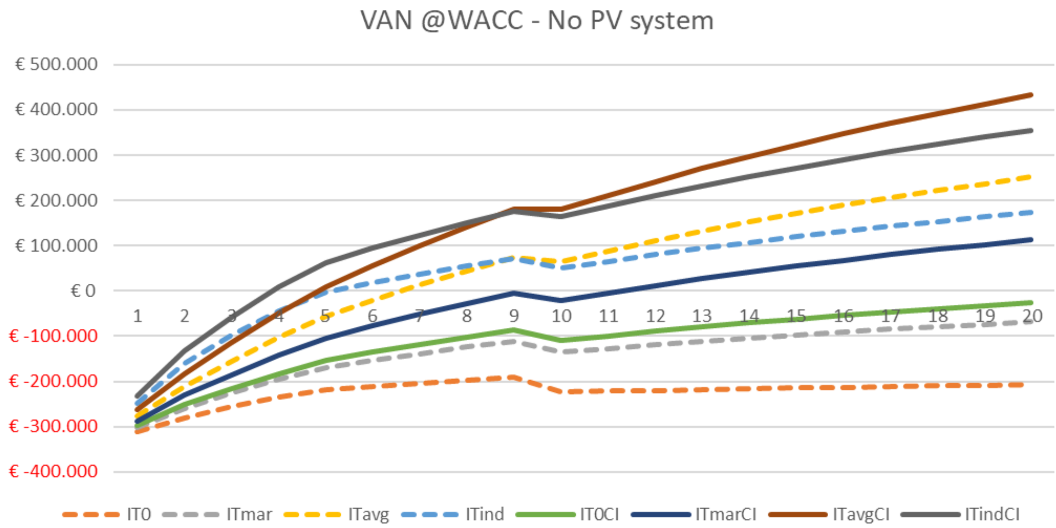


Figure 4 – Italian case: VAN without PV system

In the IT0, ITmar and IT0CI scenarios the NPV is negative, therefore the investment is not profitable in these scenarios either. The ITavgCI scenario has the highest NPV (€432,651) and the ITindCI scenario has the lowest PBT, which is less than 4 years.

The various scenarios in case of presence of photovoltaics are outlined below on the basis of VAN and IRR.

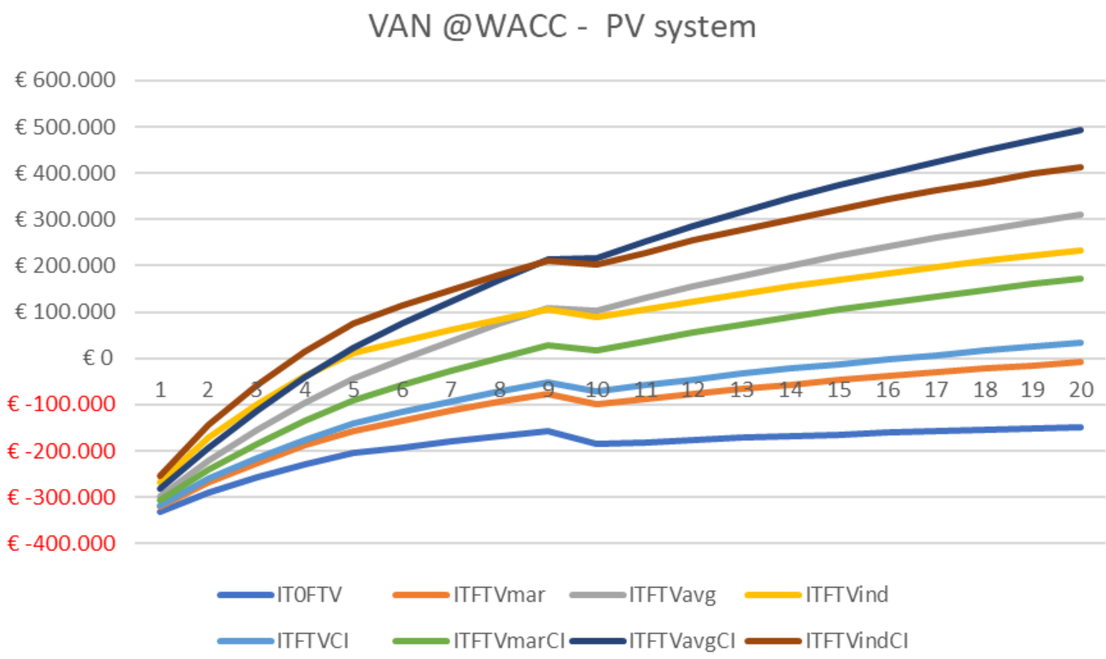


Figure 5 - Italian case: VAN with PV system

In the IT0FTV and ITFTVmar scenarios the NPV is negative, therefore the investment is not profitable in these scenarios. The ITFTVavgCI scenario has the highest NPV (€492,424) and the ITFTVindCI scenario has the lowest PBT, which is less than 4 years.

Below is the summary table of the economic indices of evaluation of the proposed scenarios.

Table 8 – Italian case: indices

Scenario	IRR	VAN	PBT
IT0	-12,3%	€ -207.590	>20,0
ITmar	1,5%	€ -68.176	>20,0
ITavg	17,5%	€ 251.658	6,6
ITind	18,1%	€ 173.436	5,1
IT0CI	4,0%	€ -26.597	>20,0
ITmarCI	11,2%	€ 112.818	11,3
ITavgCI	25,7%	€ 432.651	4,9
ITindCI	29,4%	€ 354.430	3,9
IT0FTV	-4,2%	€ -147.817	>20,0
ITFTVmar	5,1%	€ -8.403	>20,0
ITFTVavg	19,5%	€ 311.431	6,0
ITFTVind	20,7%	€ 233.209	4,8
ITFTVCI	7,2%	€ 33.176	16,2
ITFTVmarCI	13,6%	€ 172.591	7,9
ITFTVavgCI	27,2%	€ 492.424	4,7
ITFTVindCI	31,0%	€ 414.203	3,8

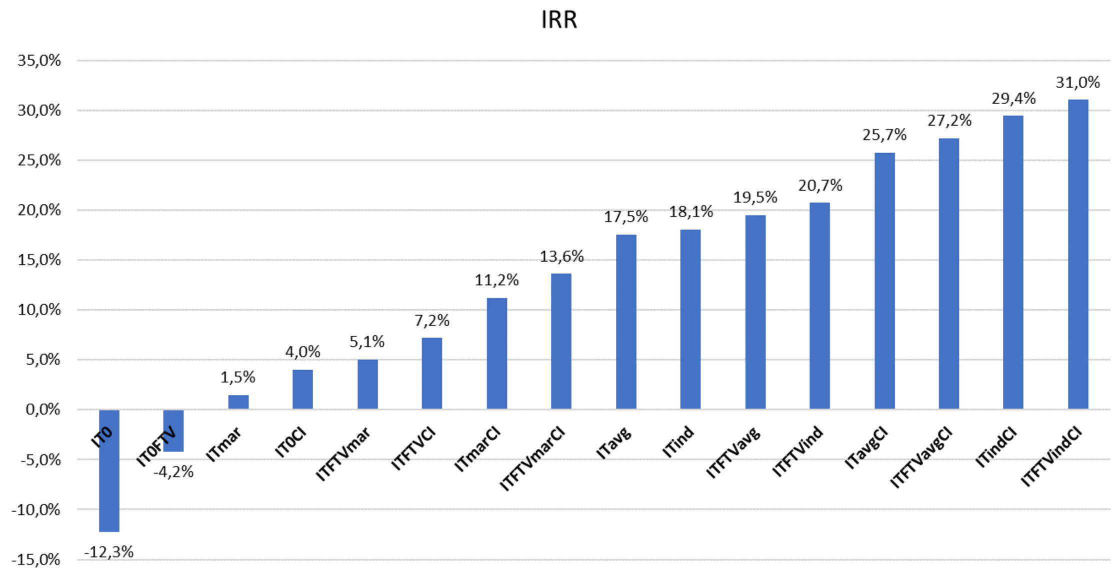


Figure 6 – Italian Case: IRR

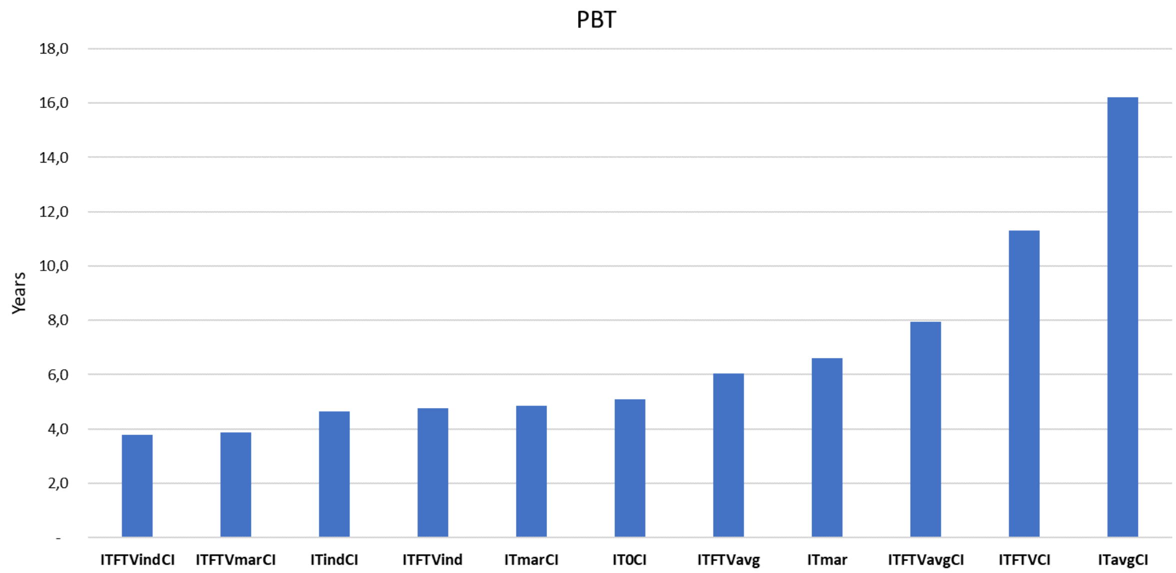


Figure 7 – Italian Case: PBT

In scenarios where heat production has an average system price (ITavg) or the gas price of an industrial customer (ITind), the NPV is positive with IRR above 17%.

When the tax credit can be obtained, all scenarios with savings from heat production (ITmarCI, ITavgCI and ITindCI) have a positive NPV with a rather high IRR.

The photovoltaic system generates a general benefit to the NPV and the IRR of all scenarios.

In conclusion, in scenarios without tax credit, the investment is profitable only when the cost of producing heat is quite high, while with the tax credit, it is sufficient that the savings are not zero, that the heat is available for free. It is always advisable to install a photovoltaic system.

3 Dutch case

3.1 District heating in the Netherlands, current situation

This section aims to present the current state of the energy system in the Netherlands, including the status of heating and district heating. By considering main features of the country's current energy situation, it will be easier to contextualize selected options introduced in the business model, with related energy, economic, and environmental impacts.

In this case, the most recent comprehensive data available for the energy sector and heating's state is sourced from CBS data updated up to 2019 (CBS and TNO 2020). Therefore, these data are considered to describe consumption, while more updated prices and legislation are considered to incorporate recent trends in energy markets. Additional, more up-to-date reports were also considered, again considering the consistency of data between different periods.

In the Netherlands, the overall primary energy consumption stands at approximately 3,000 PJ. After accounting for non-energy consumption or losses, which amount to 1,201 PJ, a significant portion of 53% is dedicated to fulfilling heating needs (985 PJ). Specifically, with regard to the innovative district heating solutions advocated by the ongoing project, it proves beneficial to focus on the heat requirements of *residential and service* buildings, constituting 46.6% (459 PJ) of the total. Low-temperature forms of district heating are in fact less suitable for the industrial setting, which requires high temperatures for activation of chemical processes or heating of fluids.

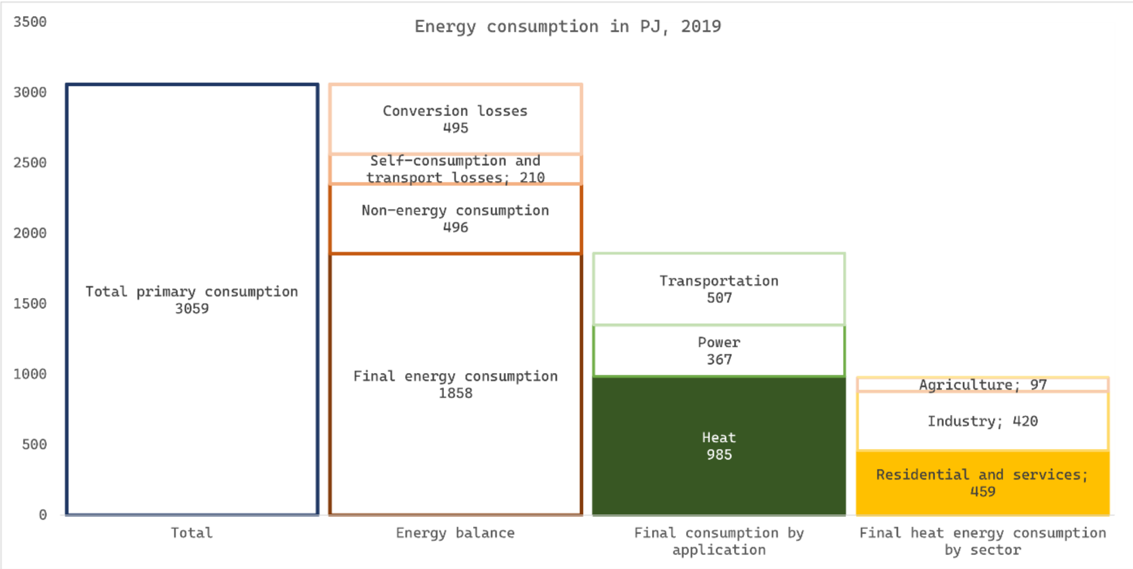


Figure 8. Breakdown of energy consumption in 2019. Source: Centraal Bureau voor de Statistiek.

The transition towards a more sustainable energy system is a key priority for the Netherlands, as outlined in the Dutch Climate Agreement (Dutch government 2019). Specifically, the agreement aims to achieve a 49% reduction in greenhouse gas emissions by 2030 compared to 1990 levels. Looking further ahead, the ultimate goal is an even more ambitious reduction of 95% by the year 2050. The European Union decided in 2020 to raise the target for cutting greenhouse gas emissions to 55% by 2030, forcing the country to make its plans more ambitious. To develop a structured action plan, the government has integrated explicit guidelines on how to achieve these objectives, categorized into five broad sector platforms.

To facilitate discussion on specific measures and instruments and to provide clear direction, each sector platform was assigned a sectorial target, quantifying the reduction in Mt emissions to be achieved by 2030.

One of the five sector platforms is specifically about the *built environment*, with sector-specific commitments. The primary objective is to achieve a substantial reduction of 3.4 Mt of carbon dioxide in the built environment by 2030, in comparison to the reference scenario. This value corresponds to almost all of the city of Amsterdam's emissions over the course of a year. In order to achieve this emission reduction, roughly 1.5 million existing homes will have to be made more sustainable, as well as a 1 Mt cut of emissions in non-residential buildings. This transformation requires the involvement and collaboration of municipalities, residents, building owners, housing associations, construction companies, and many other stakeholders. The process will be carried out incrementally until 2050 through a district-oriented approach, when 7 million homes and 1 million nonresidential buildings will have to be disconnected from natural gas connections in order to fulfill the emissions cut target (Netherlands Enterprise Agency 2022). Depending on the characteristics of the area, different solutions for heating can be more appropriate. In densely populated areas with high-rise buildings or older homes built before the 90s, a district heating grid often emerges as the most viable choice. On the other hand, in regions featuring new homes and spacious districts, an all-electric solution may prove to be the more fitting approach.

In this context, district heating can play a crucial role, considering the benefits available to stakeholders as well as the environment. Leveraging urban heat sources and efficient distribution networks, district heating offers a viable solution to Netherlands to reduce greenhouse gas emissions and advancing the decarbonization of the residential heating sector. In 2019, the situation on heating in built environment is shown in Figure 2. Out of the 459 PJ required by the built environment for heating, over 80% is still met through natural gas-fired boilers, while district heating accounts only for 4-5% share.

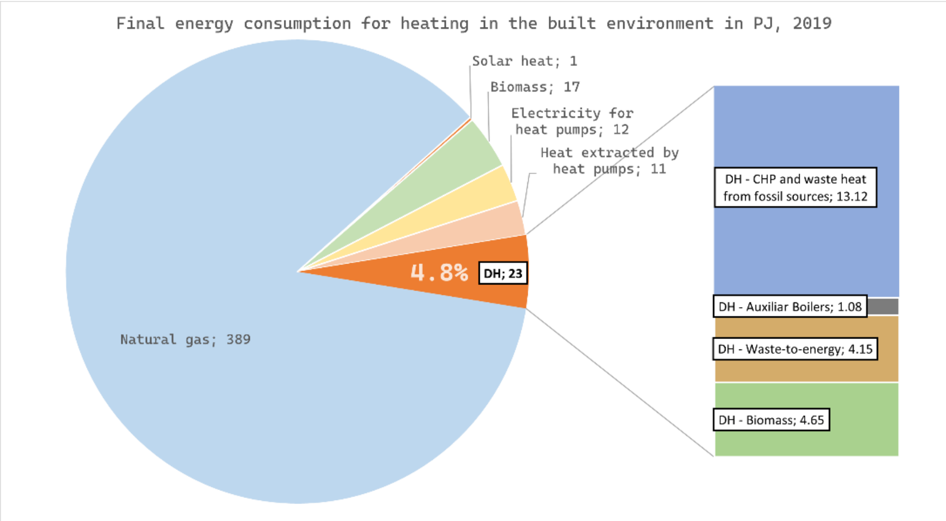


Figure 9. Final energy consumption for heating in the built environment. Focus on DH. Source: Centraal Bureau voor de Statistiek.

Notably, the Netherlands has not specified a precise target for the number of district heating connections by 2030, although consulting institute CE Delft has suggested a figure of 1.2 million connections (CE Delft 2019). Instead, the focus is on achieving an annual connection rate equivalent to 80,000 homes by 2025 (Dutch government 2019).

This increase should be matched by a less than proportional increase in final delivered heat. This should be facilitated by increasing building efficiency, shortening of the cold season, and the use of heat pumps to manage temperatures and peaks. For this reason, heat delivered is expected to increase by only 70% between 2019 (23 PJ) and 2030 (40 PJ), compared with the number of connections expected to increase by 130% over the same period.

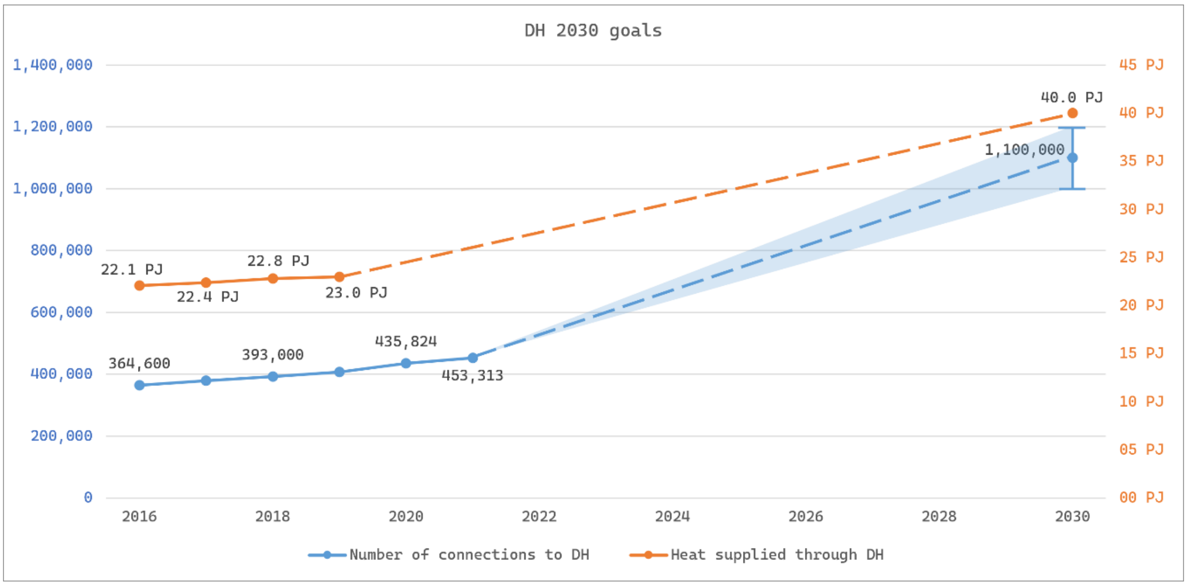


Figure 10. Forecast on connecting homes to district heating (left axis) and delivered heat (right axis) to achieve 2030 climate goals.

3.1.1 Electricity market and future price estimation

The Dutch electricity market has undergone significant changes since its full liberalization in 2004. The market is moderately concentrated, with a few major electricity suppliers, namely Vattenfall, Essent, and Eneco and a lot of small companies as well as energy cooperations. Developments have taken place since the liberalization where more companies start to become electricity suppliers, as opposed to only generating the electricity. The entry of large European vertically integrated companies, such as E.ON, Vattenfall, and Eneco, has been facilitated by the purchase of assets from former national generation and distribution companies. Nuon, Eneco, and Essent, now owned by Vattenfall, Mitsubishi Corporation (80%) and Chubu (20%) and RWE, respectively, are examples of such companies.

The Dutch government has implemented a system of full ownership unbundling in the electricity sector, which separates the ownership and control of transmission and distribution networks from that of power generation and supply. In the Netherlands, this system is implemented through the ownership of TenneT, the national high voltage electricity transmission system operator (TSO), by the Dutch state. The low and medium voltage distribution network is operated by eight distribution system operators (DSOs) through concession agreements, with Enexis, Liander, and Stedin managing over 90% of the connections. Enexis, Stedin and Liander are fully independent and are owned by provincial and local governments.

The liberalization of the Dutch electricity market has brought about a number of benefits, including increased competition, lower prices, and improved services. The entry of new players has also led to the introduction of new technologies and innovations, which have helped to enhance the efficiency and reliability of the electricity system. However, there are still some challenges to address, such as the resistance to full unbundling by some distribution companies. Overall, the liberalization of the

Dutch electricity market has had a significant impact on the industry, it will be interesting to see how this continues to evolve in the future.

The electricity price in the Netherlands is determined by the agreement made between an electricity supplier and a consumer. The price can vary based on the type of tariff scheme, the contract duration and price agreements. The different types of tariff schemes possible are fixed, variable and flexible tariffs. With a fixed tariff, a fixed price is paid per kWh, independent of market fluctuations. A variable tariff fluctuates based on market prices and changes periodically. A flexible tariff scheme is based on real-time electricity prices, which has even seen negative electricity prices in 2023.

With the goal of estimating the costs of operating heat pumps and other equipment, it was necessary to assume electricity prices until at least 2050. Energy carrier prices are highly variable, dependent on factors that are extremely difficult to predict, including supply and demand, production costs, geopolitical and environmental factors. In this case, long-term energy price estimates for the Dutch market are not available. For this reason, we chose to use the prices estimated by the energy consultancy company *Energy Brainpool*. The forecast shows future spot prices for energy.

Considering the different excise taxes and surcharges from different suppliers and variable transmission and distribution charges, it was decided to calculate the final energy price in an alternative way. Statistics Netherlands makes available the average energy price trends over the past few years for multiple price levels: spot prices, distribution and transmission prices, prices that include energy excise taxes, and energy VAT. The average percentage offset between the spot price and the final price (excluding VAT) from 2009 and 2023 was then calculated and applied to electricity price forecast. What has emerged is that the price of spot energy has typically increased between 45% and 90%, with an average of 78%.

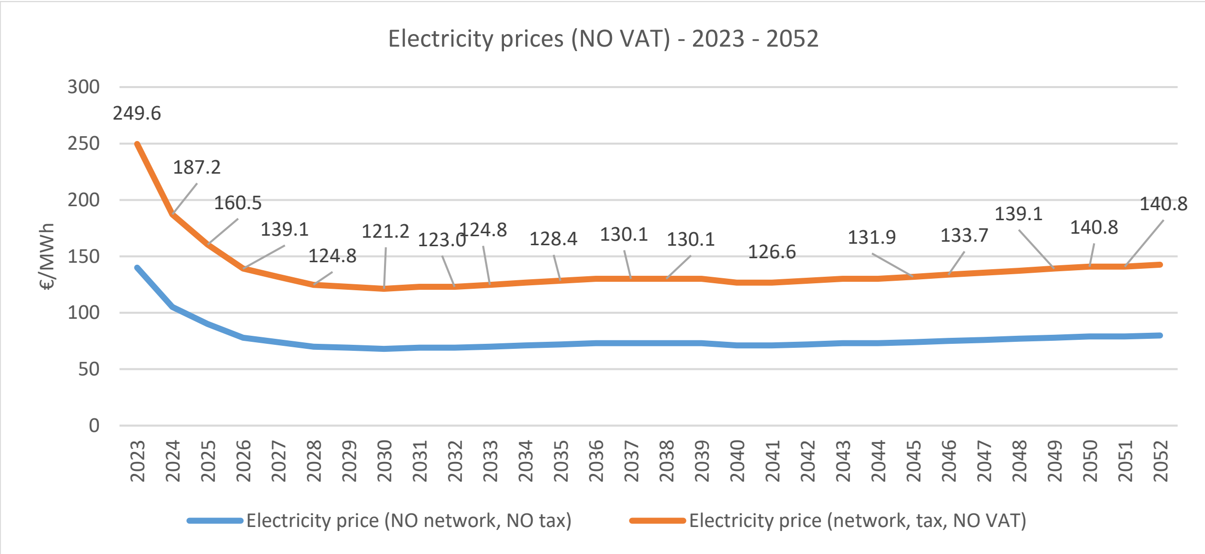


Figure 11. Electricity price projections for the Netherlands.

3.1.2 Inflation

Inflation is also necessary data to avoid overestimating future profits. Since this is a value that is more a consequence of market dynamicity, it is difficult to predict what will happen specifically in the energy sector. For this reason, inflation has been used in order to adjust administrative, operational, and maintenance labor costs. Heat sales tariffs are only partially adjusted for inflation, specifically, only the fixed portion dependent on the customer's housing type.

Many forecasts have been used to estimate the inflation figure. A prudent approach was adopted, considering the higher values, which are reflected above all in the costs incurred by the utility company. In addition to the short-term estimates of the European Commission, the Organization for Economic Co-operation and Development, BNP Paribas, in the long term (until 2030) the International Monetary Fund and the Dutch Central Bank estimate inflation at 2%. Again, according to these institutes, after 2030 we will return to pre-crisis levels. For this reason, inflation was estimated at 1.53% in the long term, equal to the average inflation between 2005 and 2019.

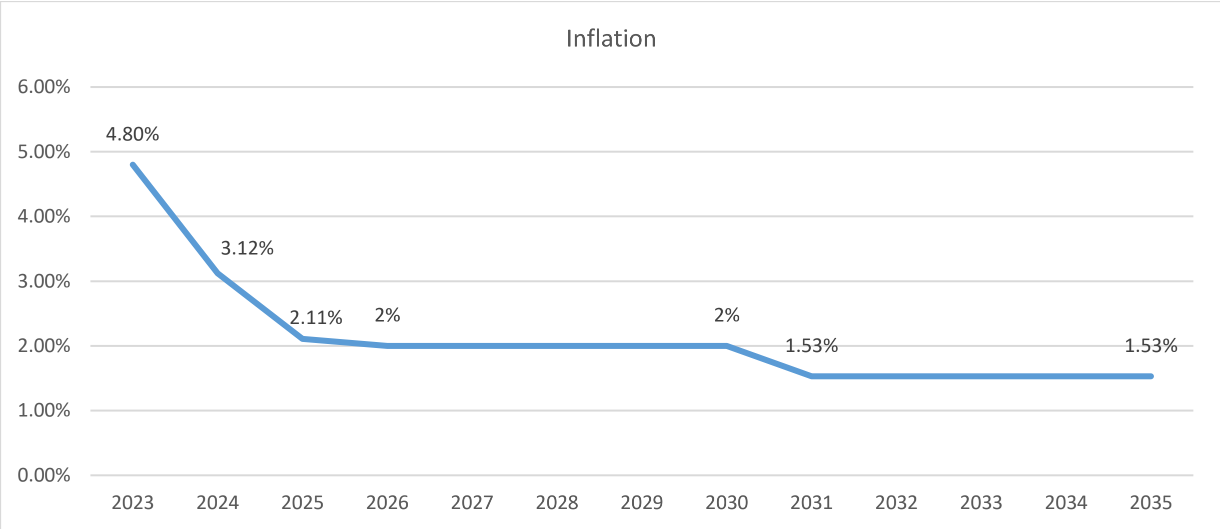


Figure 12. Inflation projection for the Netherlands.

3.1.3 Natural gas market and future price estimation

The gas operation market in the Netherlands has been of great importance to the country's prosperity since the discovery of the Groningen gas field in 1959. The Nederlandse Aardolie Maatschappij (NAM), a joint venture between Shell and ExxonMobil, has played a key role in the extraction of oil and natural gas. Over time, various agreements and collaborations were established, known as "Gasgebouw". The NAM obtained concessions from the state and worked closely with the government on compensation, sales, and transportation arrangements.

While EBN, which is 100% owned by the Dutch State, as a separate organization, represents the interests of the government in gas production in the Netherlands. In the early 1960s, the operation of the Groningen field was entrusted to the NAM as the concession holder, while the responsibility for policy was given to the Maatschap Groningen. Within the Maatschap, the NAM holds a 60% interest, while EBN holds a 40% interest. At the same time, Gasunie was established, with the Dutch government owning 10%, EBN owning 40%, and Shell and ExxonMobil each owning 25%. Gasunie was tasked with the transportation and sale of gas from Groningen.

In 2005, Gasunie was split into a transportation company and a trading company due to the liberalization of the gas market. The transportation company remained as Gasunie and came under full ownership of the Dutch government. The trading company took the place of Gasunie in the Gasgebouw and continued under the name GasTerra, maintaining the existing ownership structure: 40% owned by EBN, 25% by Shell, 25% by ExxonMobil, and 10% by the Dutch government. GasTerra assumed the responsibility of gas trading within the Gasgebouw framework. Gasunie, on the other hand, was entrusted with the task of transporting gas from the Groningen field, ensuring its safe and efficient distribution throughout the Netherlands. Gasunie rapidly built a nationwide gas network to connect households across the country to Groningen gas.

In recent years, the gas operation market in the Netherlands has faced challenges. Concerns over induced earthquakes have led to a reduction in production from the Groningen field. As a result, the country is focusing on diversifying its energy mix and transitioning to renewable energy sources. The Dutch government has implemented measures to accelerate this transition, including the gradual phase-out of gas extraction from Groningen by 2030. This transition has created opportunities for renewable energy players and is part of the country's efforts to reduce its carbon footprint and achieve climate goals.

The gas price in the Netherlands is determined by international gas markets, infrastructure costs, taxes and other government policies. The gas price is dependent on the contract a consumer has agreed upon. The contract can be a fixed price contract, where a fixed tariff is agreed upon for the contract duration, or it can be a variable price contract, which can fluctuate based on market conditions.

Estimating natural gas prices was necessary for the business case which will be discussed later. Gas prices are needed to economically compare the savings achieved by replacing gas heating systems. Just as in the case of electricity prices, the price of gas is also subject to geopolitical and environmental factors that are difficult to predict.

Also in this case, it was decided to take into account as many opinions as possible, trying to understand any divergences. What emerges is a progressive decrease in prices until 2030, when the price should settle at pre-crisis levels. For this reason, an attempt was made to summarize the opinions of various actors in a single figure, and to take into account the average gas price from 2031 onwards. The prices of natural gas futures at the Dutch TTF, the opinion of the International Energy Agency and to a lesser extent the forecasts of financial institutions and investment funds were considered.

As in the case of electricity, the price of the raw material was adapted to the final price for the citizen, considering the average offset between the spot price of gas and that including transport, distribution, energy taxes between 2009 and 2022 in the Netherlands.

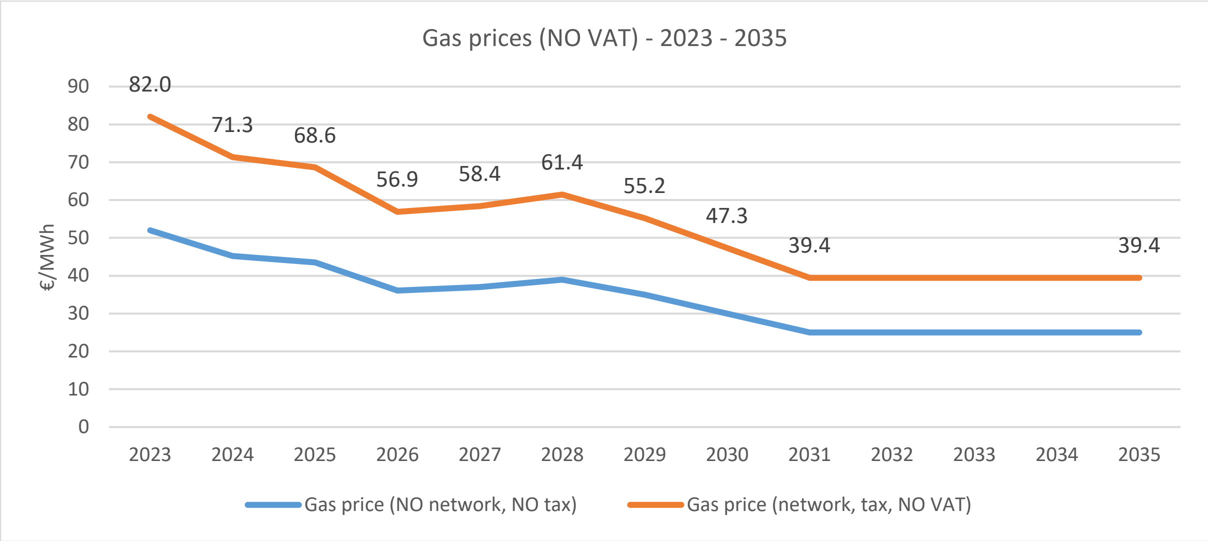


Figure 13. Gas price projection for the Netherlands.

3.2 Legislation

In the Netherlands, energy and environmental policies are mainly regulated at the national level.

Warmtewet (Heat Act) is the current law regulating the provision of district heating and cooling to ensure transparency, efficiency and consumer protection. In particular, network operators are obliged to meet quality and reliability standards in service delivery, as well as being the ones responsible for maintaining, expanding and upgrading networks. Unlike energy networks, heating companies must by law be integrated, so that production, transport and delivery are all carried out by one company, due to the very local nature of heat supply. The law requires the ACM (Authority for Consumers and Markets) to set annual limit prices that suppliers can charge for the supply of heat to users. This limit is intended to protect small end users (households and small businesses). Specifically, the ACM defines five tariff components: heat supply, metering, connection, disconnection, and heat exchanger rental. The first two components depend directly on the cost of natural gas and the operational costs of transporting and delivering it, as well as the efficiency of heat production in the Netherlands. Heat suppliers must therefore adjust annually to these maximum rates. In conclusion, the following table summarizes maximum fixed and variable part applicable for the supply in year 2023 (including 21% VAT):

ACM maximum tariffs for small consumers (final maximum connection <100kW), 2023		
	Direct contract with destring heating supplier	Contract with apartment owners' associations (VvE) or homeowner Owner costs – Centralized connection to DH grid
The user needs to increase the temperature with heat pump	**Fixed rate**: €301.47/year **Fixed tariff for storage**: €76.28/year (for each additional kW over 3kW) **Consumption**: no cost	
The user has hot water directly available	**Fixed rate**: €549.58/year **Consumption** (up to 37 GJ): €47.38/GJ **Consumption** (over 37 GJ): €90.91/GJ	**Fixed rate**: €549.58/year **Consumption**: €90.91/GJ

The tariffs protect first of all the owners of homes who directly stipulate a supply contract with the district heating operator. The citizen is therefore directly protected by the Heat Law.

In the Netherlands it is equally common for people to be tenants of private landlords or part of owners' associations (VvE). Unless apartments are equipped with individual heating systems, building owners (or the association) are considered the heat suppliers. If district heating is used, users are not protected by the heat law, but owners are. In this case, the owner enters into a single district heating supplier contract and supplies the heat to the tenants. Heating is part of the service charge and, under the *Tenancy Act*, the landlord is only required to charge reasonable costs to tenants, who are therefore indirectly protected by law.

Finally, there are cases where tenants still receive central heating, but not from district heating networks, such as ATES systems owned by landlords. In this situation there is a direct agreement between owner and user, which however is not protected by the Heat Act.

Regarding the connection of new housing units, the ACM still sets maximum rates. The one-time connection fee is €5,337.39, plus a maximum of €315.40 for each additional meter beyond 25 meters of distance between the building and the network pipe. The operator is also allowed to charge an additional annual connection fee for the investment incurred to connect new customers, though still reasonable.

All the prices calculated have the aim of observing the principle imposed by the law of *no more than otherwise*, according to which a user should not pay more than one with the most common alternative, that of the gas boiler. In fact, more than 80% of demand is currently satisfied by the combustion of natural gas in individual boilers. Therefore, increases in gas price are also reflected in increases in the cost of heat supply, although this is not always matched by an increase in the cost of heat production (at least 38% of the heat delivered is not produced with natural gas, Figure 9). Price caps apply to utilities with end connection of less than 100 kW. For large customers (heat demand greater than 100 kW), the law does not provide a maximum tariff on prices; in this case, the customers' greater bargaining power is relied upon to negotiate a fair deal given the high heat demand.

Critical challenges related to pricing and network implementation are expected to be addressed through a comprehensive revision of the law under the new *Wet collectieve warmtevoorziening* (Dutch Collective Heat Supply Act). The law is expected to be voted on in 2024 and go into effect by January 2025, and bring several innovations in the areas of market regulation, price transparency, sustainability, and investment attraction. The ultimate aim of the new proposed law is, however, to ensure a faster transition from gas heating to new, potentially more efficient forms, such as district heating.

One of the most important passages of the new law would be the one on tariffs. According to the rules, the price of heat for the end customer should be based on the cost of producing the heat. The ACM should therefore no longer pronounce on maximum tariffs, as each network would experience a different and unique scenario, with completely different tariffs. The ACM would still rule on excessively high prices or disproportionate profits of network operators. The operator would in fact be free to charge an additional fee on top of the cost of heat production, to cover investments and operations.

The law assigns greater responsibilities to local authorities (municipalities and regions, which would assume a managerial role in the strategic choices of construction or expansion of the district heating network. The municipality will have full autonomy in the designation of heating areas, i.e. a medium-long term plan that indicates which heating technologies to use and in which areas. The municipality would also be responsible for designating the company responsible for heating, with exclusive right to supply. The company is ultimately responsible for the entire heat chain (production, transportation, and supply), as well as maintenance, construction, and efficiency operations. The operator may collaborate with other companies, although it always remains the manager of operations. In fact, one of the major criticisms of the current regulations is the lack of a clear framework of obligations and responsibilities. The government foresees a 7-year implementation plan of this law.

An important amendment wanted by the Minister of Climate and Energy provides for greater public ownership in the area of district heating. In particular, the law provides that 50%+1 of the shares of a district heating company with more than 1500 customers should come under public control (State, province, municipality, other public entities). The amendment is still unclear, but multiple possible configurations would be possible.

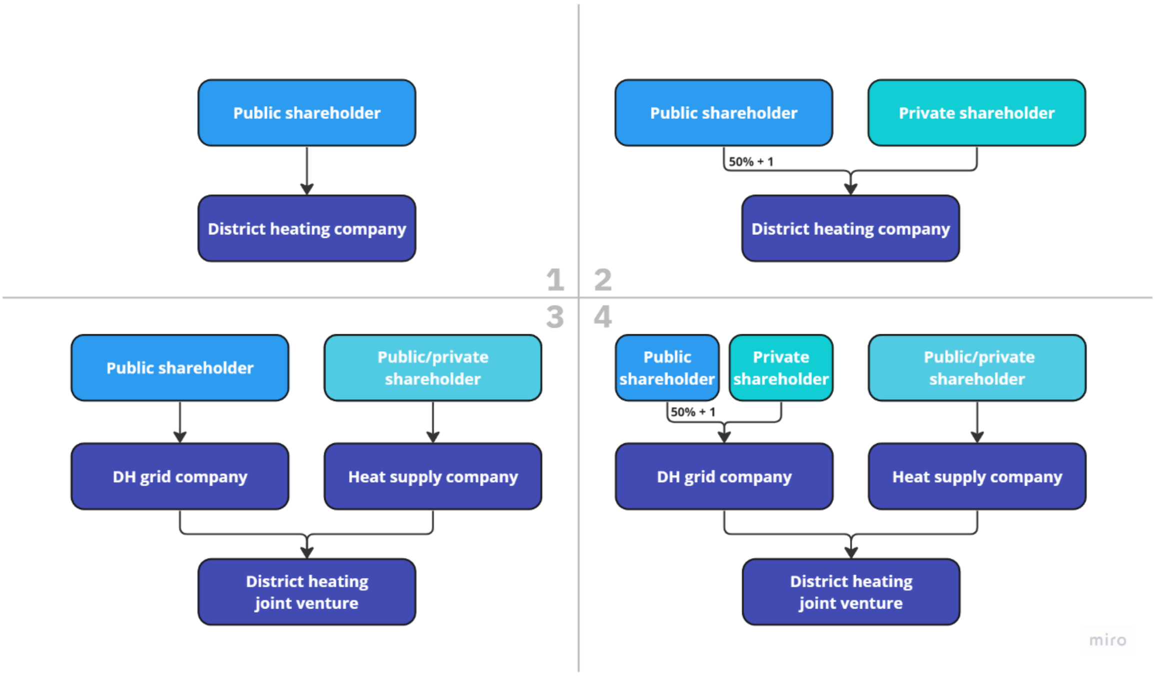


Figure 14. Ownership scenarios in the Dutch DH sector.

What emerges is that the government considers strategic not so much the integrated heating company as a whole, but rather the heat transport infrastructure (heat network). This choice responds to the desire of local authorities for the infrastructure to be public owned. The choice is also in line with the policy on gas, electricity and water. A joint venture would also be possible between a company responsible only for the transport of heat and one responsible for the production and delivery of heat, as in cases 3 and 4 in Figure 14. The government has commissioned *PwC* to investigate the possible effects of requiring public ownership of networks. According to the report, the disadvantages of this law would outweigh its benefits. In particular, the possible reduction in competition between private companies during the designation phase and lower private investments are highlighted. Private operators would in fact find themselves negotiating from a minority position on the distribution of risks and profits. In addition, the majority of risks would remain of private concern, considering that heat delivery is associated with higher risks than its transport.

From the entry into force of the law, a period of up to 30 years is also foreseen for the first new designation and transfer into public control. This period would serve to ensure the recovery of investments undertaken before the sale of the shares. In this case the public body will not have to "expropriate" the company assets, but simply purchase them at market value. While waiting for the transition to public control, investments would be strongly discouraged, compromising the achievement of the 2030 and 2050 environmental objectives.

Another significant aspect pertains to waste heat. The proposed law states that a waste heat producer that discharges such heat must make the heat available to a district heating company on request and free of charge. This obligation concerns residual heat (unavoidable thermal energy) that is generated as a by-product in the operational management of a company and which, if not fed into a heat network, would remain unused in the air or water. The heat company will have to pay the producer's *decoupling* *costs*, consisting of the actual costs incurred by the heat producer to make the waste heat available to the heat company.

3.2.1 Other relevant legislation

Heat networks are mainly regulated by the Heat Act, but some other regulations influence heat networks. The most important laws are the *Environment Act*, *Housing and Tenancy Acts* and laws regulating the energy markets.

The Environment Act combines all laws relating to the physical environment into one law. The Environment Act makes it possible to request all legal permissions needed for a heat network at once, making it easier to start building projects. Furthermore, a foundation of the Act is the participation of the local environment. The Environment Act is planned to go into effect on January 1st, 2024.

The Dutch Housing Act does not contain specific regulations about heat networks, but it is connected to heat networks. The Housing Act regulates and sets requirements for the energy performance, disputes over prices, ownership of the system, and services of Dutch houses.

3.2.2 Corporate income tax

The Dutch Corporate income tax, known as *vennootschapsbelasting* in Dutch, is applicable to the profits of companies conducting business activities in the Netherlands. The tax rates for corporate income tax are determined based on the amount of profits made. In 2023 there are two tariffs for the corporate income tax:

• For taxable profits up to €200,000, the tax rate is 19%.

• For taxable profits exceeding €200,000, the tax rate is 25.8%.

3.3 Incentives

A discussion on the main incentives considerations that affect the business model follows. What we considered below are based on the current situation for the 2023 tax year.

3.3.1 Heat Networks Investments Subsidy (WIS)

The Heat Networks Investments subsidy (WIS) is a subsidy for investments in heat grids for small consumer connections (less than 100 kW) and block connections in existing housing. The heat network supplies heat to spaces and water in existing houses. WIS can provide subsidies to projects that would be unprofitable, meaning the project cannot go out without subsidy. Over the unprofitable part of the investments, a 100 % subsidy can be received. A maximum of 45 % of the total investment costs can be covered by this subsidy, or a maximum subsidy of €6.000 per connection < 100 kW.

A project is eligible for the subsidy if at least 250 small consumer connections are connected to a heat network within the project. Furthermore, the duration of the project is no longer than 7 years and within 3 years after the grant funding, the physical construction of the heat grid must be started. The new heat network has to meet the requirements for energy-efficient district heating and cooling, according to item 124 of Article 2 of the General Block Exemption Regulation (AGVV).

The total budget available for the WIS is €150 million from June 1st to December 23rd, 2023. The maximum subsidy amount that can be received per project is €20 million.

3.3.2 Stimulation of Sustainable Energy Production and Climate Transition (SDE++)

The SDE++ incentive offers companies and non-profit organizations subsidies for generating renewable energy on a large scale or for reducing CO2 emissions. It subsidizes the 'unprofitable portion', which is the difference between the cost price and the market remuneration. Therefore, market changes also affect the amount of subsidy received. The SDE++ is an operating grant, meaning that the subsidy is received during the operating period of an installation. The subsidy amount received depends on the amount of renewable energy generated, the amount of CO2 reduction, and the market price.

The subsidy is for either 12 or 15 years, depending on the installation used. Over these years, it is possible to receive different subsidy amounts, depending on the energy price. The subsidy can be used for five different categories:

- Renewable electricity
- Renewable gas
- Renewable and waste heating
- CO2 low heating
- CO2 low production

Each category has its base amount per kWh, which is the maximum amount for which you can ask subsidy. The base amount is fixed for the duration of the subsidy.

The subsidy amount received is reduced by the revenues earned with the installation, including certificates Guarantee of Origin (GvO) and emission rights from the Emission Trading System (ETS). Based on the yearly average revenues, a correction amount is determined. The correction amount determines the amount of subsidy received in €/kWh. Furthermore, if an SDE++ subsidy is used, other subsidies can no longer be requested like the Investment subsidy for renewable energy and energy savings (ISDE), Energy Investment Allowance (EIA), and/or Cooperative Energy Generation Subsidy (SCE).

Specific techniques have a higher grant intensity to make it more likely the techniques are addressed, because these techniques are short term less cost-effective, but are long-term necessary for the energy transition. For each technique, €750 million is reserved to stimulate these projects. These techniques include 'low-temperature heating' and 'high-temperature heating'.

3.3.3 Natural gas-free rental housing grant scheme (SAH)

The SAH offers a subsidy for existing buildings that are going off the natural gas network within 5 years. These homes are or will be, connected to a heat network. The SAH subsidy can be requested by a mixed association of owners (VvE) or an owner of one or more rental properties.

The subsidy is available for needed home modifications and for connection costs to a heat grid. For needed home modifications, 40 % of the costs are subsidized, with a maximum of €1.200 per home. 30 % of the costs for connecting the home to the heat grid are subsidized, with a maximum of €3.800 per home. If a home is already connected to a heat grid, home modifications for connection to the heat grid are still available.

The total budget available for the SAH subsidy is 195.3 million over the application period from 2020 to 2023. Of these €195.3 million, €10 million is for subsidy requests smaller than €25.000, and €185.3 million is for requests of €25.000 or more.

3.3.4 Energy Investment Allowance (EIA)

The EIA is a tax deduction scheme for companies who are investing in CO2 reduction, energy-efficient techniques, and/or renewable energy. A list is available that shows all the eligible investments for the EIA, which includes investments like heat pumps. Heat networks are excluded from the list because of the separate subsidy that focusses on heat networks (see 3.4.1). The budget available for 2023 is 249 million. A minimum energy investment of 2.500 is required per asset to be eligible. A tax deduction of 45.5 % of the invested amount is available through this incentive.

3.3.5 Investment subsidy for renewable energy and energy savings (ISDE)

The ISDE is a subsidy available for home-owners and companies, which offers a subsidy for taking sustainable and energy savings measures in their home or business property. The subsidy offers compensation for a part of the purchase costs for solar boilers, heat pumps, creating a connection to a heat grid, electric hobs, and insulation measures.

The amount of subsidy received for the measure or device is dependent on the type used. The subsidy is around 20 % of the average investment costs for the taken measure. A connection to a heat network receives a fixed subsidy of €3,325. The budget available for ISDE is 350 million for 2023. The ISDE subsidy continues until 2030.

3.3.6 Program for natural gas-free neighbourhoods (PAW)

The PAW offers living labs for natural gas-free neighbourhoods a contribution from the government. In total 66 municipalities are participating in this program. The municipalities can choose how they want to become natural gas-free. Experiences from this program will show the best methods available. From 2018 until 2030, around 380 million is available for natural gas-free neighbourhoods in the PAW program.

3.3.7 NieuweWarmteNu / Groeifonds

Through NieuweWarmteNu! An investment is made in 12 sustainable collective heat network projects. These projects have great scaling-up potential and are replicable in other places. In addition to these projects, investments are also made in innovations that can make essential technologies market-ready. The budget available is 200 million, granted through the National Growth Fund (NGF) in 2022.

3.3.8 Insulation subsidies

The Netherlands has several insulation subsidies which are necessary to be able to connect certain buildings to heat networks. The ISDE-subsidy explained above offers subsidy for insulation, but there is also the Grant scheme for sustainability for owners' associations (SVVE), which also offers subsidy for insulation measures. A budget of 48.5 million is available from January 1st 2023 till December 31st 2027 for energy advice and sustainability measures for owners associations (VVEs). Furthermore, a VAT reduction is introduced in 2019 on the labor costs for insulation, reducing the costs from 21% to 9%.

3.4 Key partnership

Key partners are often across all cases analyzed (Italian and Danish). Those that are most relevant to the Dutch case, or that need some clarification based on the existing legislation and situation, are described here.

- Municipalities
- Equipment suppliers (prefabricated SKIDs, heat pumps, boilers, pipes...)
- Designers, contractor, builder
- Financial institution, ESCo

3.4.1 Municipalities

The role of municipalities as key partners in new generations of district heating will be increasingly crucial. Municipalities can play an important role especially in coordinating and facilitating the development, but also the subsequent operation, of collective heating systems.

First of all, municipalities have been given the responsibility to improve the sustainability of the built environment, and they are required to develop a plan on how to make the districts more sustainable. This plan includes the transition to natural-gas-free heating systems by 2030, as agreed in the Climate Agreement. The municipality's role is to identify the districts to be tackled and envision the final sustainable picture by 2050.

The municipality should act as a *coordinator* in various aspects of the project. It plays a central role in bringing together stakeholders, such as heat source providers and operators, and facilitate the necessary permits and authorizations for the implementation of the district heating network. The municipality also acts as an impartial mediator in negotiations between private parties, ensuring that the needs of all stakeholders are met. In the new Collective Heat Supply Act, it is envisioned that municipalities will take an *initiator* role: there is a need for a strong-willed figure to exist, especially in projects aimed at integrating many actors. Indeed, scenarios could arise in which one party would not make its move, before another has not fulfilled its duties, and vice versa. It happens then, that heat suppliers, financiers, operators are not willing to act until data on technical feasibility and network adjustments are available, and at the same time such actions are difficult to evaluate without clear references from those actors. The municipality would need decision-making tools to break any deadlock and maintain the parties' commitment to the development process, which should happen with the new Collective Heat Supply Act.

Moreover, the municipality's strong connections with local stakeholders, as well as provincial and national governments, make them well-suited for a central role. They can leverage their relationships to garner support and resources for the project.

While the municipality may require external expertise in managing the development of district heating networks, they have the ambition, time, and patience to see the project through. Their commitment to energy efficiency, CO2 reduction, and sustainability aligns with the goals of the district heating initiative, more than other parties. For this reason, it would be optimal to form public-private partnerships with a long-term perspective (PPPs).

3.4.2 Contractors

The energy transition in the Netherlands also requires considering builders and specialized installers as critical resource partners in this process. As the country strives to reduce carbon emissions and switch to sustainable energy sources, the demand for skilled workers in the construction and installation sector will reach unprecedented levels.

The ambition of upgrading the built environment through new generation of district heating will require multiple human resources. Heat pump technicians, electricians, plumbers, civil engineers, contractors specializing in the installation of thermal systems... are all key figures, which will need to be properly coordinated on both the infrastructure, heat production, and housing sides. In a 2022 analysis, the Dutch *Employee Insurance Agency* (UWV) alerts the government to how climate goals in the built environment cannot be met with the current state of the world of work (Het Financieele Dagblad, 2022). In particular, the analysis points to how there were already 46,000 vacancies in construction-relevant occupations in 2021, regardless of energy efficiency-related jobs. And these numbers apply only to the built environment, not to mention that the other areas of the Dutch Climate Agreement often need the same expertise.

The scale and urgency of the energy transition have posed significant challenges, especially in terms of human resources. A substantial shortage of qualified workers has emerged, impacting the industry's capacity to meet the ambitious climate goals set by the government. This shortage of personnel hampers the progress of renewable energy projects, energy-efficient retrofits, and the implementation of innovative technologies.

The report warns that not only new professionals need to gain knowledge, but existing employees also need to continue to update their knowledge. Carpenters, tilers, city workers... will also need to know how to perform the actions required by the implementation of district heating networks. The subsequent need for service and maintenance will also be an opportunity for the labour market.

The gap between the demand and availability of qualified personnel is widening, hindering the speed and efficiency required to achieve the desired energy transition outcomes. What this model proposes is increasing *industrialization* and *mechanization* in the construction industry, which would allow for minimization of labour hours on the site through prefabrication and construction standardization.

3.4.3 Equipment suppliers

The success of the district heating initiative relies heavily on reliable and efficient equipment suppliers. These partners play a crucial role in providing essential components such as prefabricated SKIDs, heat pumps, boilers, and pipes. The collaboration with reputable equipment suppliers ensures the quality and durability of the heating infrastructure. Moreover, these suppliers contribute to the optimization of energy transfer and distribution systems, enhancing the overall efficiency of the district heating network. The business model acknowledges the significance of a robust supply chain, fostering partnerships with equipment suppliers committed to technological innovation, sustainability, and meeting the specific demands of the district heating industry.

3.4.4 Heat producers and prosumers

In the context of district heating, heat producers and prosumers play a pivotal role in shaping the dynamics of the thermal network. These entities encompass a spectrum of actors, ranging from industrial facilities to commercial enterprises, which not only consume heat but actively contribute to its generation through their production processes. The interplay between these heat-producing entities and the district heating system introduces novel opportunities for synergy and efficiency.

Under the evolving legislative frameworks, a win-win situation would appear to be created between the prosumer and the utility company when it comes to waste heat. It becomes a shared resource that benefits both the contributing industry and the broader district heating network. The utility company would enjoy the waste heat created by the heat prosumer for free, to then resell to end customers. The heat prosumer would benefit from connection to the district heating network, with the possibility of replacing his own heating source with an intelligent system, capable of autonomously managing the introduction of heat into the network, self-consumption of his own heat, and withdrawal of heat from the network. By replacing pre-existing fossil fuel heating systems, prosumer efficiency is certainly achieved.

3.5 Customer segments

District heating networks cater to a diverse range of customers, spanning from private residences to commercial buildings and public facilities. For homeowners and residential communities, district heating offers a convenient and sustainable heating solution. Local networks offer citizens the opportunity to disengage from the gas grid and eliminate gas or oil boilers, which are riskier solutions with usage prices subject to fuel fluctuations. A first avoided cost is that of annual boiler maintenance, which averages €138.82 for gas boilers, €200-250 for oil boilers (CE Delft 2022). Of the approximately 8 million houses in the Netherlands (CBS Statline 2023), 40% (3.4 million) are in the hands of housing companies and individuals given for rent. Of these, 67% (2.1 million) are in the hands of housing companies. In conclusion, a quarter of the country's housing stock is owned by real estate companies (CBS Statline 2023). The Dutch government estimates that 1.2 million housing units will be added to the current housing stock over the next 15 years. This business model therefore proposes that district heating operators leverage real estate companies and project developers of new homes as drivers to acquire new customers. An additional incentive to switch to district heating will be provided by the ban on installing gas boilers. The legislation is not yet finalized but is expected to have affect from 2026, necessarily widening the market affected by new heating ways.

Achievement of climate goals still requires connection to district heating networks in the existing living environment. Most of the existing housing stock can be represented by three basic types: single-family houses, apartment with shared entrance, apartment building. Netherlands Enterprise Agency (Atriensis projects 2022) has estimated what the costs might be for connecting these different housing types, with the costs incurred by the operator and the household.

District heating networks are also adapted to supply customers such as commercial and public buildings. Municipalities themselves, as participants in district heating companies, would first require their own buildings to be connected. Private and public offices, hospitals, schools, shopping complexes, sports centers, libraries, and hotels are all to be considered as potential customers, as they are often located in densely populated areas where network efficiency is greater. Complexes of this kind could already have central heating systems, which would make connection immediate and easy. Again, it is the building owner who is the target customer for operators to address, not the end user.

3.6 Value proposition

The value proposition of the business model lies in addressing the pressing need for sustainable heating solutions in the Netherlands, particularly in the context of the ambitious climate goals outlined in the Dutch Climate Agreement. As the government aims for a 49% reduction in greenhouse gas emissions by 2030 and a 95% reduction by 2050, the business model aligns with this vision by focusing on district heating solutions. The primary value proposition stems from the ability of district heating to contribute significantly to the decarbonization of the residential heating sector, a critical aspect highlighted in the government's emission reduction targets.

Given that over 80% of heating in the built environment is still met through natural gas-fired boilers, the business model proposes a transition to district heating as a sustainable alternative. District heating networks, leveraging urban heat sources and efficient distribution networks, offer a viable solution to reduce greenhouse gas emissions. The approach considers the distinctive characteristics of different regions, proposing district heating grids in densely populated areas with high-rise buildings or older homes and all-electric solutions in regions featuring new homes and spacious districts.

Furthermore, the business model strategically positions itself to play a crucial role in achieving the targets outlined in the new Wet collectieve warmtevoorziening (Dutch Collective Heat Supply Act). By emphasizing the integration of explicit guidelines, including market regulation, price transparency, sustainability, and investment attraction, the model aligns with the evolving legislative landscape. The proposed law, expected to take effect by January 2025, aims to ensure a faster transition from gas heating to more efficient forms, such as district heating.

3.7 Cost and revenue structure

In this section, we explore various energy trading schemes between utility companies and waste heat producers, considering their implications for both customers and the environment. To give concreteness and reproducibility to the possible trading schemes, the demo site developed by Mijnwater in the city of Heerlen within the LIFE4HeatRecovery project is discussed, along with its assumptions and constraints.

The different scenarios consider current and future regulatory requirements for district heating in the Netherlands, as well as the utility company's access to government subsidies. The main actors taken into consideration in the following scenarios are:

- *Mijnwater*: the utility company, manager of the fourth/fifth generation network of *Parkstad* Limburg (a conurbation of 7 municipalities) which exploits the old mining tunnels as a heat source and buffer.
- *VDL Casting*: Heerlen foundry, specialized above all in the iron and cast-iron production of products for the automotive industry.
- *Hoensbroek public swimming pool*: facility which is currently using gas boilers to heat rooms, the changing room water and the swimming pool water. Within cluster D of the network, it is the main user candidate for connection to the *clusternet*, with the aim of removing the gas boilers.
- *Domestic users*: domestic users in the same neighborhood as the swimming pool are also considered to evaluate differences in connection to a single customer versus many household connections.

As previously mentioned, the analysis encompasses a variety of scenarios, some of which are based on the existing Heat Act as the regulatory framework over the entire assessment period. In contrast, other scenarios examine the potential implications if the project were to progress under the forthcoming Collective Heat Act. It is not yet clear when the new law will take effect, given the parliamentary steps that have not yet begun, but it is assumed to be between mid-2024 and early 2025. The discussion on the new law is not only of Dutch national interest, considering that in other European countries new methods of pricing and management of district heating supply, similar to the new Dutch proposal, are being discussed.

Recent increases in energy prices have inevitably had an impact on the prices of heat supplied via district heating. However, there is not always a correlation between these increases, triggering discussions on pricing management or possible speculation on the part of suppliers. The new Collective Heat Supply Act also deals with these aspects. On the one hand, an attempt is being made to reduce the share of fossil fuels used in heat production, in line with national environmental objectives. In this regard, the new law recognizes, among other things, utility companies the right to recover waste heat free of charge where available. Another aspect is that of tariffs: in countries such as the Netherlands and Italy there has been an increase in district heating prices as a consequence of the increase in gas prices, even if, in some cases, the use of gas in production is marginal. The new law requires utilities to apply prices for end customers strictly linked to the actual costs incurred by the company, as is already the case in Denmark.

In conclusion, the following analyzed scenarios are of absolute relevance also for other countries besides the Netherlands, because they explore the results resulting from different managerial and legislative choices.

Scenario	Final main user	Legislation and pricing	Incentives & subsides
#1	Swimming pool Hoensbroek	Project contract	
#2	Swimming pool Hoensbroek	Project contract	SDE++
#3	Swimming pool Hoensbroek	Warmtewet 20% less than gas price	
#4	Swimming pool Hoensbroek	Warmtewet 20% less than gas price	SDE++
#5	Swimming pool Hoensbroek	WCW cost-dependent	
#6	Swimming pool Hoensbroek	WCW cost-dependent	SDE++
#7	Households	Warmtewet Related to ACM maximum	
#8	Households	Warmtewet Related to ACM maximum	SDE++

The only subsidy considered in the scenarios is the SDE++, a Dutch structural measure that focuses on companies that make investments and guarantees a reduction in emissions. Other measures, however, were initially neglected. They concern the adoption of low-emission systems for domestic end customers or state investment funds, the extent of which is however difficult to assess because their availability is variable or assessed on a case-by-case basis.

Below are some energy and cost figures considered in all scenarios, regarding VDL:

- the heat exchanger system installed by Mijnwater at VDL Casting can recover about 4315 GJ (1200 MWh) each year, with an average thermal output of 227 kW.
- The heat recovery contract does not involve any payment between the parties.
- It is assumed that VDL's request to first use the heat for office heating is met. VDL's interest is in replacing its heating systems, any cost of adapting the heating systems is at VDL's expense.
- In the absence of a monitoring system for only the offices involved in office heating, the following data are considered to estimate the heat demand of VDL:

Gross Floor Area (GFA)	1930 m^2
Room height	2.5 m
Wall heat exchange capacity (U)	0.25 $W/(m^2*K)$

Average temperature in Heerlen	12 °C
Average ΔT required	8 K
Average opening time (on 360 days)	10 h
$Power = (GFA + Walls\ area) * U * \Delta T$	8598.63 W
Heat demand → **Preventive approach**	30.96 MWh → **46 MWh**

- VDL would require approximately 31 MWh per year for heating, considering a preventive approach of +50%, a demand of 46 MWh/y is considered.
- The heat is already available to be fed into the grid, given that the Heerlen grid is low temperature.

The contract between VDL and Mijnwater therefore provides that VDL can withdraw part of the heat for heating its offices, provided that VDL bears any costs for the installation and maintenance of the systems necessary for heating.

Mijnwater recommends considering an average loss of between 1 and 2% of thermal energy for each kilometer of network. For a precautionary approach, a 2% loss of heat is considered in the section connecting VDL with Hoensbroek swimming pool.

The utility does not have heat demand measurement systems for each of its spaces. For this purpose, past general heat demand was used, averaged over two years' data. What emerges is that the heat supplied by VDL could only cover between 45 and 55% of the pool's demand. However, the water temperature is not high enough for the needs of the pool, considering that the Heerlen network is at a low temperature. 8 water-to-water heat pumps with a thermal output of 53.8 kW have been installed, and the related electricity consumption is considered, being the main operational expense item of the project. The total heat provided by district heating and temperature raising should be just enough to meet the need of the pool. Although no other heat sources are available in the cluster to date, any extra demand could be met from the city's main grid backbone. The electrical consumption of the water distribution pumps was also considered, which Mijnwater estimates as 1% of the heat.

Regarding the depreciation of installed assets, Dutch legislation considers 30 years to be an adequate period for the life cycle of systems and technology. For pipes, the depreciation period goes up to 50 years. For all scenarios, a period of 30 years is considered as a reasonable period in which to recover from the investment, in line with the depreciation period of the assets. For this reason, all assets are depreciated at constant rates over 30 years.

For the analysis of the investment, it was necessary to decide on an adequate WACC level for discounting the cash flows. The decision fell on the value calculated by the consultancy firm Brattle, at the request of ACM. When estimating maximum heating tariffs, ACM must take into account that utility company profits do not exceed a reasonable level. For this reason, it requires Brattle to estimate the WACC level every year, taking into account the market of the 20 largest district heating supply companies. The latest available data is 4.23%, in line with previous years (with a maximum of 4.97% in 2020). Although a low level of WACC might not seem very precautionary, it must be considered that the investment in question, although it represents an innovative paradigm in the sector, is part of a process of gradual but constant growth and efficiency which in the case of Mijnwater began in 2008. Although dependent on the energy sector, the investment falls within a sector with high certainty of future cash flows and medium-low volatility.

3.7.1 Scenario #1

The first simulated scenario is the one most similar to the real case, considering that at the time of planning the connection in the cluster, Mijnwater was not yet aware of the new legislation coming in. In this case, the pricing system actually stipulated in the agreement between Mijnwater and public pools is applied. In this case, the installed power connection is higher than the maximums needed to come under the ACM price protection regiment. The contract is assumed to have an indefinite term (as in the actual case). The pool pays a fixed annual connection fee of €27,320. It is assumed that this fee contributes entirely to cover any maintenance and administrative costs borne by Mijnwater, even in the case of major unscheduled maintenance activities. According to the contract, the pool is required to pay 136,000€ for the first 1,583 MWh of heat, even if the heat used should be less. After this threshold, the contract calls for a payment of €158.40/MWh.

Although the connection power exceeds the limits for which pricing would be protected by the limits set by ACM, the price is for the needs of the pool still below this maximum, as can be seen from the following chart. It should be noted that with regard to the maximum ACM rates, the case where water is directly available to the customer is considered, as it is still the supplier (Mijnwater) who is economically and technically responsible for the operation of the heat pumps.

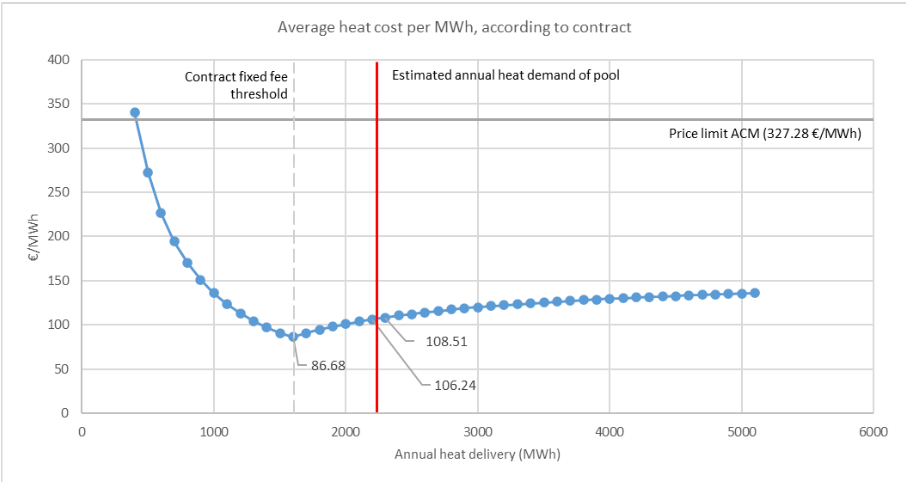


Figure 15. Heat cost analysis for the Dutch case.

As mentioned, it is Mijnwater that is contractually responsible for the operation of the heat pumps. Relative to them, the supplier is responsible for bearing the cost of electricity, routine and extraordinary maintenance, possible replacement over the years.

Regarding the costs of construction, materials and technologies, the costs actually incurred are considered, given that the project is as of today completed and ready for operation. In conclusion, the investment scenario is highly beneficial and appealing, with an expected return within 9 years from the current year (the year the system goes into operation). The expected NPV is 1.4 million, ROI of 176%, IRR 10.2%.

What stands out is the higher heating cost between the use of gas boilers and the new connection to the district heating network. The variable part of this cost for district heating is between 20 and 150 percent more expensive than the corresponding variable part for gas, according to the gas price estimates adopted.

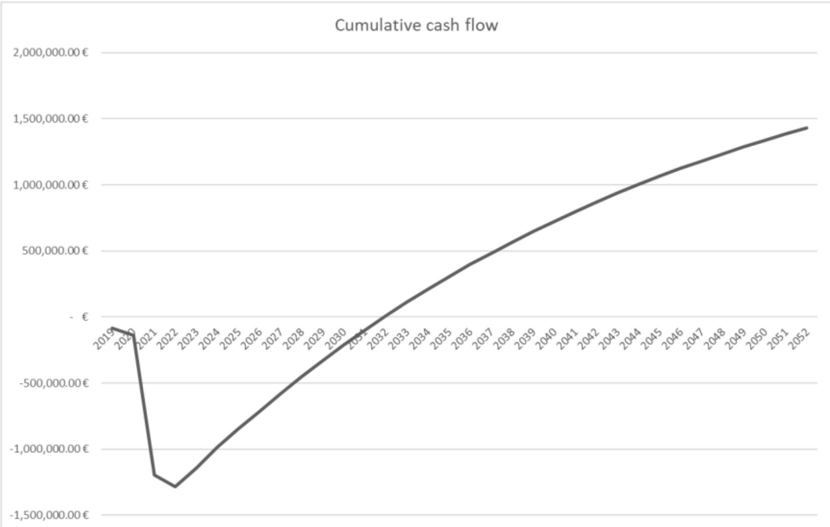


Figure 16. Cumulative cash flow for the Dutch case.

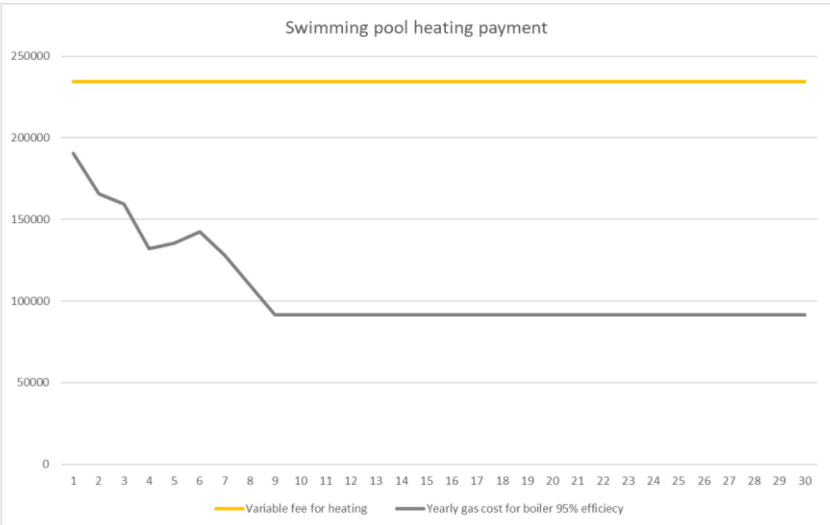


Figure 17. Comparison between expected fee and estimated gas price for the Dutch case.

3.7.2 Scenario #2

The second scenario starts from the same assumptions as the first, but introduces the possibility of receiving the SDE++ subsidy. This subsidy appears to be well predictable, unlike other generic government investments for project implementation with few terms to establish its claimability and amount. In this case, the subsidy would be aimed at Mijnwater, as the promoter and financier of a project capable of guaranteeing a lower impact compared to a pre-existing situation, in this case replacing natural gas heating systems. There is a very specific category that concerns the case, that of recovery of residual heat, with the need to increase the temperature using heat pumps. The volume of the subsidy also depends on the ratio between length (between recovery point and delivery point) and power, in this case greater than 0.4 km/MWh. The subsidy is available for the first 15 years from the entry into operation of the system and works as follows: the subsidy provides for a base price (minimum threshold) and a base rate (maximum reference point). The company that benefits from it must demonstrate how profitable the unit of energy produced and sold is: to do this, profits, operating costs, depreciation costs of assets are distributed over the quantity of energy delivered, in order to calculate the profit coming from each energy unit delivered.

- If the value is below the base price level, the company benefits from the maximum amount of the subsidy, calculated as the difference between the base rate and the base price.
- If the value is between the base price and the base rate, the company benefits from a subsidy calculated as the difference between the base rate and the actual profitability of the energy.
- If the value is above the base rate, the company does not benefit from any subsidy.

The following image shows the case in question:

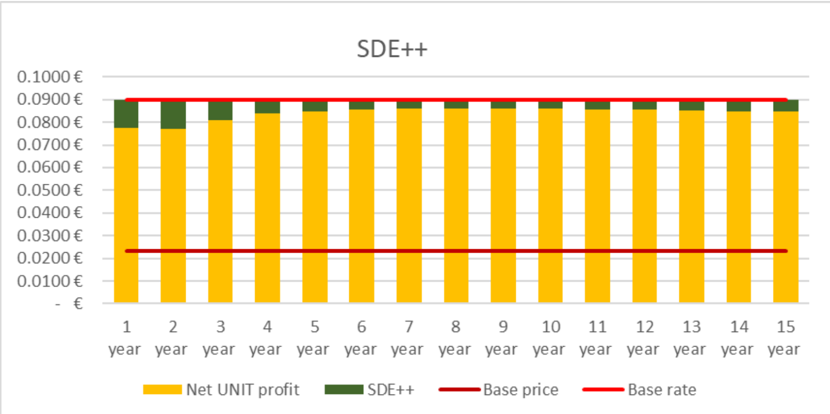


Figure 18. Incentive scheme considered for the Dutch case.

Mijnwater would receive an annual fee of between €8,000 and €28,000. The subsidy would therefore represent between 4 and 14% of the annual turnover of this project in the first 15 years (turnover coming solely from the sale of heat to the pool). The subsidy therefore takes on a certain importance, especially in the first years of the system's entry into operation.

As regards the cost incurred by the swimming pool for heating, nothing changes to the previous case, because the subsidy affects the profitability of the utility company but not on the sales rates.

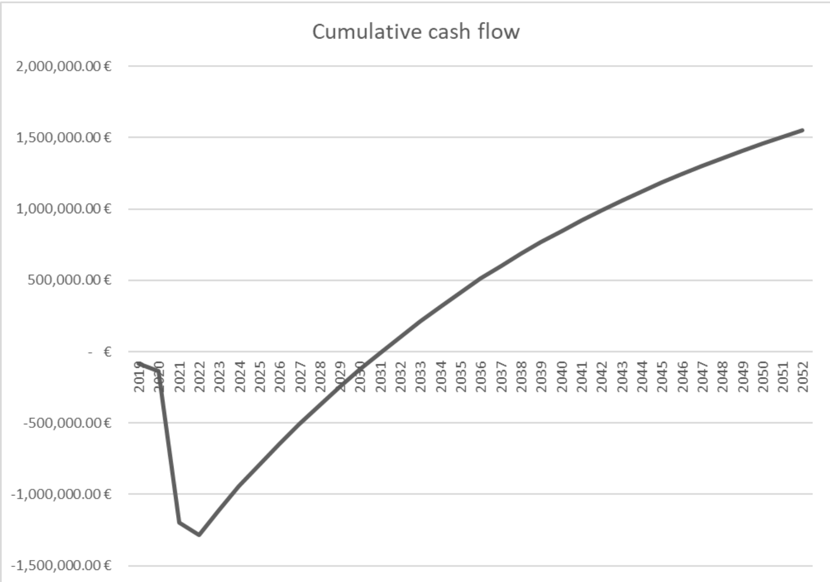


Figure 19. Cumulative cash flow for scenario 2 of the Dutch case.

3.7.3 Scenario #3

The third and fourth scenarios investigate a different case of heat pricing and sales. The previous assumptions remain identical, except for the existing contract between provider and user. As already mentioned, the swimming pool does not fall under ACM's tariff protection system, according to which heat prices should not be higher than gas prices and would be blocked by the maximum tariffs decided by ACM. Nonetheless, the possibility is being investigated that Mijnwater applies the same conditions to the pool that it usually applies to domestic customers. It is not possible to predict what the future tariffs applied by the supplier will be, but the supplier reports charging rates that are generally 20% below the cost of gas. Aware of this, we apply this approach throughout the period under consideration, based on estimated natural gas tariffs. As for the fixed connection fee, it remains the same as in previous cases.

In the next graph, the expected cash flows according to these assumptions:

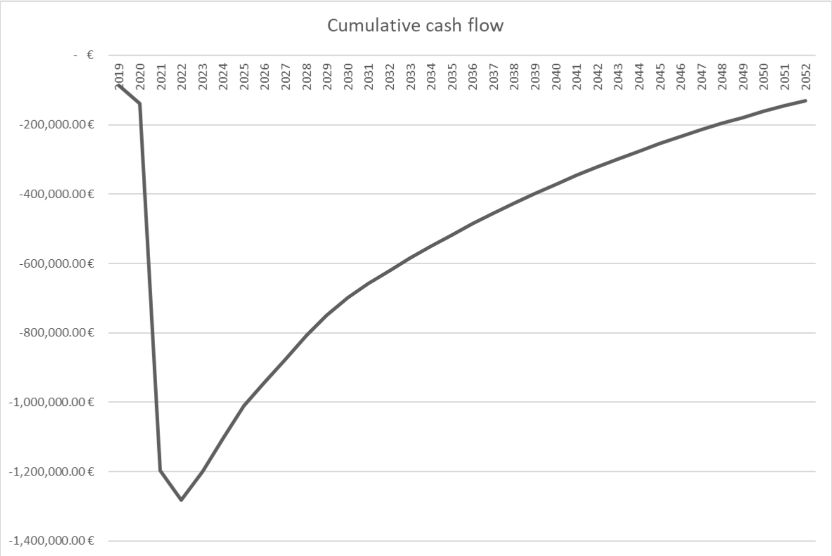


Figure 20. Cumulative cash flow for scenario 3 of the Dutch case.

As is evident from the graph, the investment is unprofitable and actionable. During the 30 years under analysis, the investment is not repaid by the only expected income, that of the heat tariff. It is evident from the graph on the costs of the heating pool that the cost of heat is up to a third lower in this scenario than in the previous scenarios.

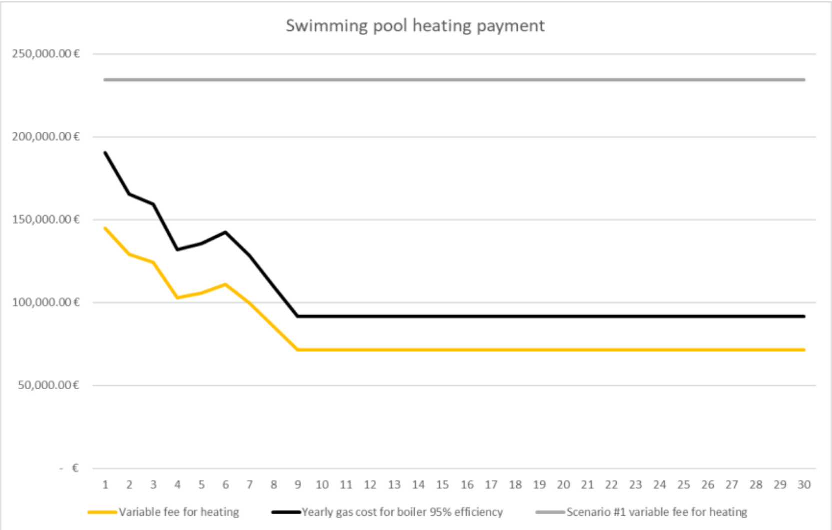
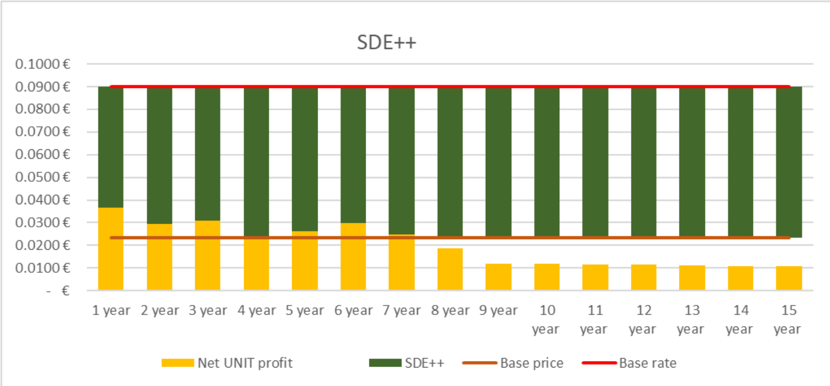


Figure 21. Comparison between expected fee and estimated gas price for the Dutch case, scenario 3.

3.7.4 Scenario #4

Scenario 4 turns out to be quite similar to the previous one, but applying the SDE++ contribution in the first 15 years after the system goes into operation. Below are graphs of the level per unit energy of the contribution and the cash flow analysis of the investment.



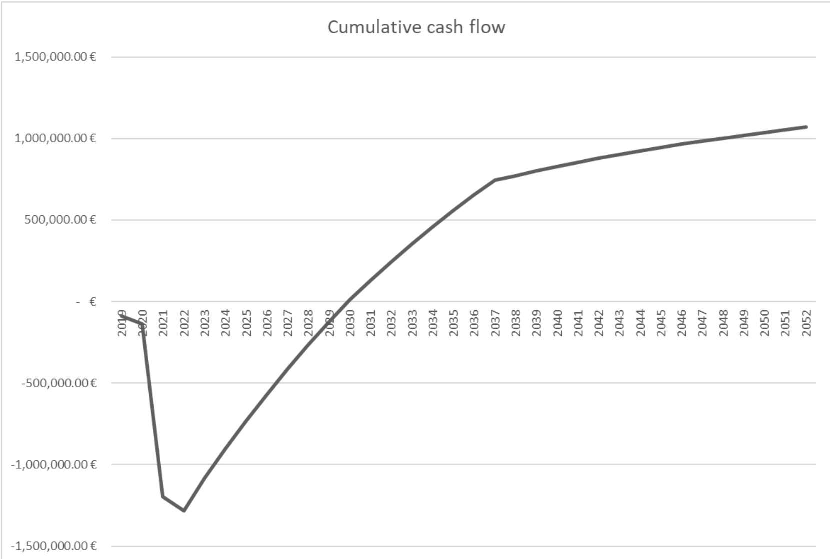


Figure 22. Incentives and cumulative cash flow for Dutch case, scenario 4.

The scenario turns out to be extremely profitable, with a return expected even earlier than the first two scenarios. The break-even point is estimated at the seventh period. The great credit for this improvement is due to the SDE++ contribution, which would constitute up to 67% of revenue in some periods.

The success of this scenario relies solely on the SDE++ contribution, so its eligibility should be ensured during the design and development phase. It may be complicated, if not impossible, to apply so far in advance for grant eligibility, given that the application process does not include such an administrative process. This scenario must therefore be considered profitable but risky.

3.7.5 Scenario #5

Scenario 5 and 6 attempt to predict the effect of the application of upcoming act terms on the pricing of heat sales. As explained above, the new Collective Heat Supply Act obliges the supplier to charge a tariff that reflects the costs incurred by the company to generate, collect, and deliver that heat.

It continues to be assumed that the fixed fee paid to Mijnwater was commensurate to ensure that administrative and maintenance costs were covered.

As regards the variable part for heat, this reflects operating costs and depreciation costs. In the first 10 years, the variable portion also integrates the non-amortizable part of the initial investment.

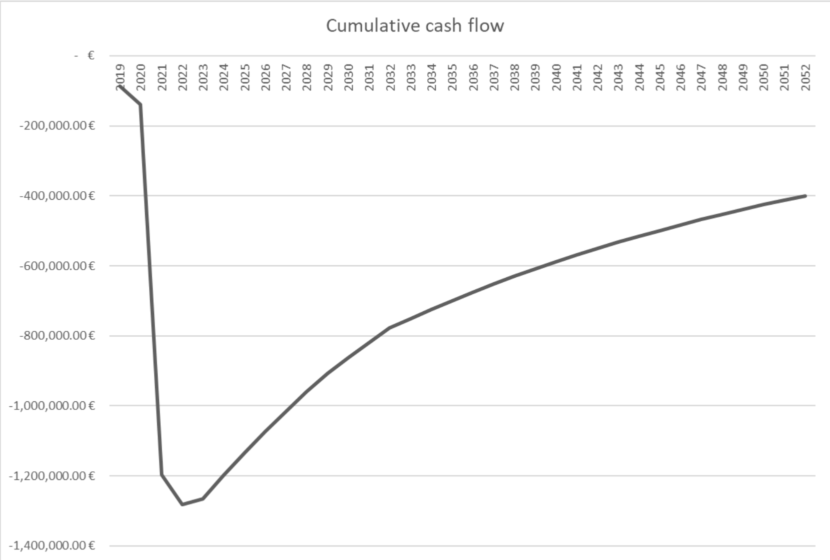
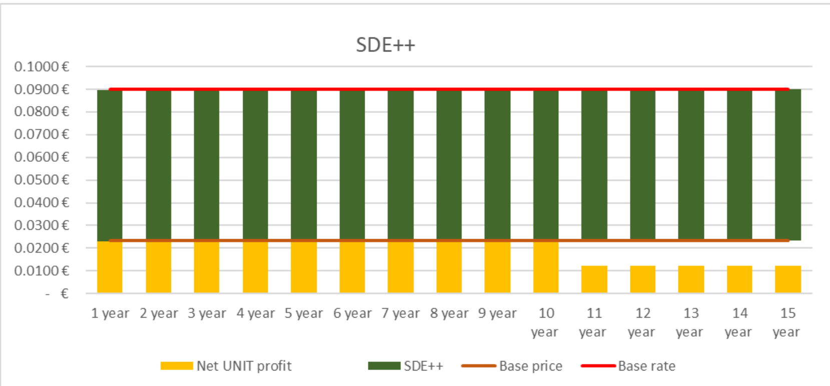


Figure 23. Cumulative cash flow for scenario 5 of the Dutch case.

Although the pricing system is designed to reflect the costs incurred by the company, the discounting of cash flows demonstrates that the investment is not very interesting, and that a return from it would not be guaranteed within the period under analysis. To guarantee a return within the 30 periods, it would be necessary to increase tariffs by between 40 and 50% of their current value. Hypothesizing a higher share to guarantee the profitability of the investment is realistic, but such a high share would generate tariffs up to three times higher than what would be paid for the production of hot water with a natural gas boiler.

3.7.6 Scenario #6

As in previous cases, a new scenario hypothesizes state incentives as a means to make the investment more attractive. Once again, the choice falls on the SDE++ subsidy. As never before, the subsidy paid would be the maximum possible for all 15 periods under consideration.



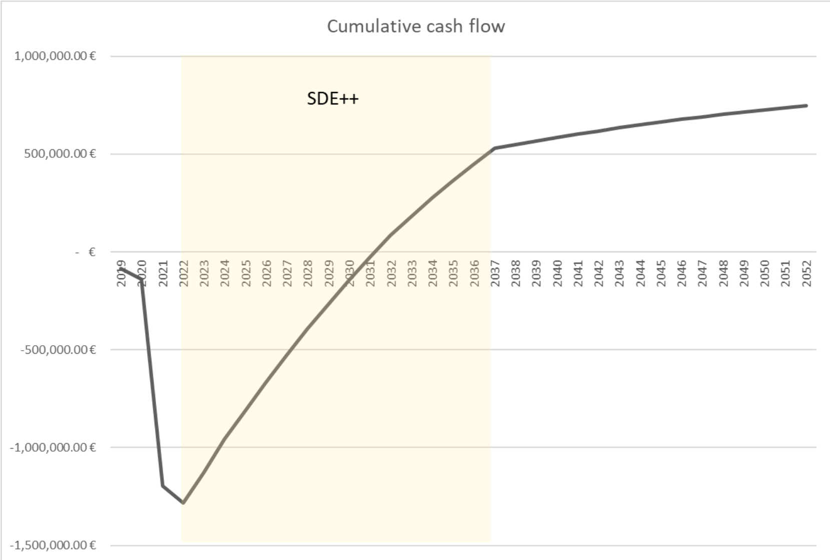


Figure 24. Incentives and cumulative cash flow for scenario 6 of the Dutch case.

The scenario now shows the possibility of breakeven by the ninth period, with a projected NPV of €0.75 million, ROI 42%, IRR 8.6%.

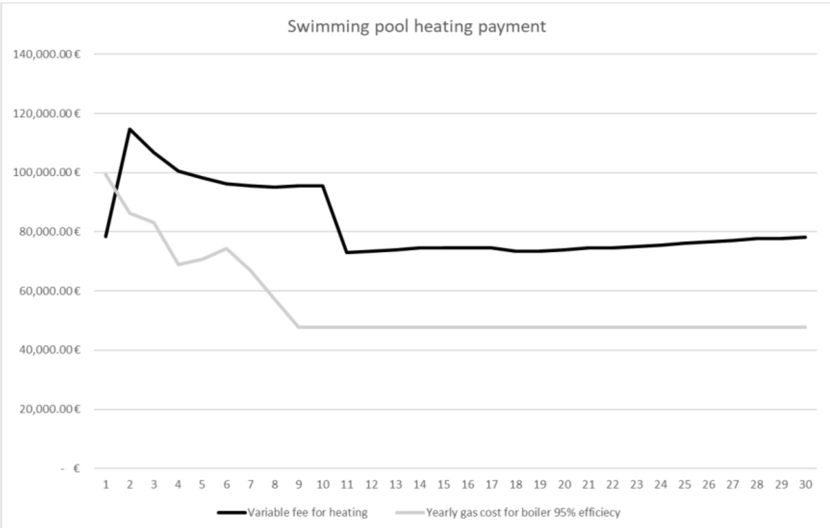


Figure 25. Tariffs of district heating vs gas in scenario 6 of the Dutch case.

The comparison with the use of natural gas shows how the tariffs are still higher for district heating, but with an average of 50% more in the 30 periods analyzed. The profitability of the investment would still be guaranteed even if the tariffs were reduced to a price similar to that which would be paid for the gas alternative. Nonetheless, what these scenarios demonstrate is that a law that attempts to decouple tariffs from the price of gas may not be enough without state subsidies aimed at improving the profitability of the investing company. Apart from this, the new law would better protect customers from prices unfairly linked to the price of gas and greater distribution of the benefit deriving from the investment (at the expense of lower profitability for the company).

3.7.7 Scenario #7

In the seventh and eighth cases, the return on investment in the case of a change of end user is explored. As for the charging system, current legislation is applied. Instead of a commercial customer, such as the pool customer, we assume to connect a number of users who collectively require the same heat as the pool annually. Again, any peak demand that goes beyond the availability in the cluster is handled by drawing from the grid backbone.

It continues to be hypothesized that Mijnwater is responsible for increasing the temperature of the water via the same heat pumps. By doing so, customers would receive water available for direct use. To evaluate how many customers could benefit from the heat generated by VDL and increased by Mijnwater, we use the data on the average gas consumption per household for heating in Heerlen, available from the Dutch statistics platform. The result is that 105 homes in the cluster can be connected to the grid, calculated with a Dutch standard lower heating value of 8.79 kWh/m^3 and average boiler efficiency of 95%. Pricing for a private customer is directly or indirectly subject to the price limit, imposed by law and implemented by ACM. However, the pricing system is more complex, encompassing various cost items. In this case, the administrative costs are covered by the metering fee, while the installation and maintenance costs of heat exchange systems at homes is fully covered by the heat exchange kit rental fee.

As for the fixed connection fee, the maximum fees for 2023 and 2024 were used, while they were adjusted for the inflation rate for the following years. The fixed rate charged to customers is 90% of the estimated maximum rate.

The maximum variable tariffs for 2023 and 2024 were also used as available, while they were estimated for the following periods. In this case they were adjusted to the expected gas price for each year, varying the tariff proportionally from year to year based on the year-on-year percentage change in gas prices. The applied rates are 5% lower than the maximum calculated rates.

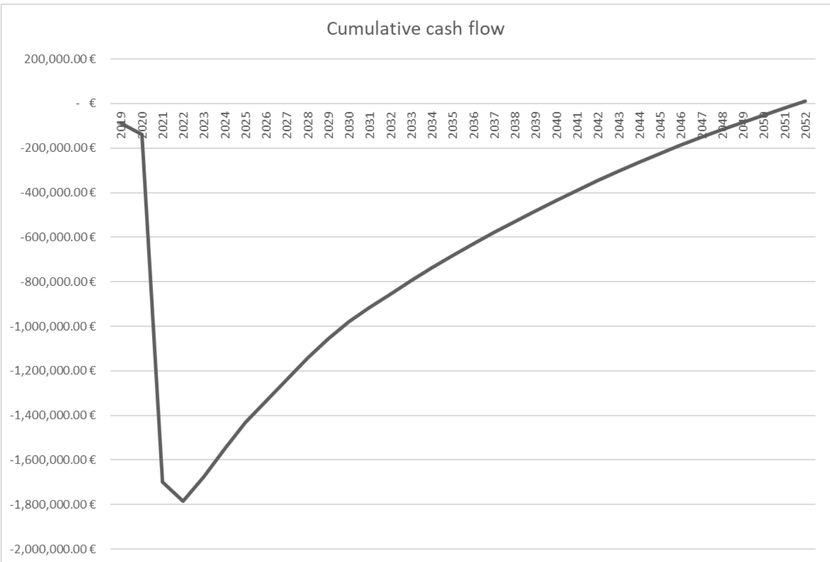


Figure 26. Cumulative cash flow for scenario 7 of the Dutch case.

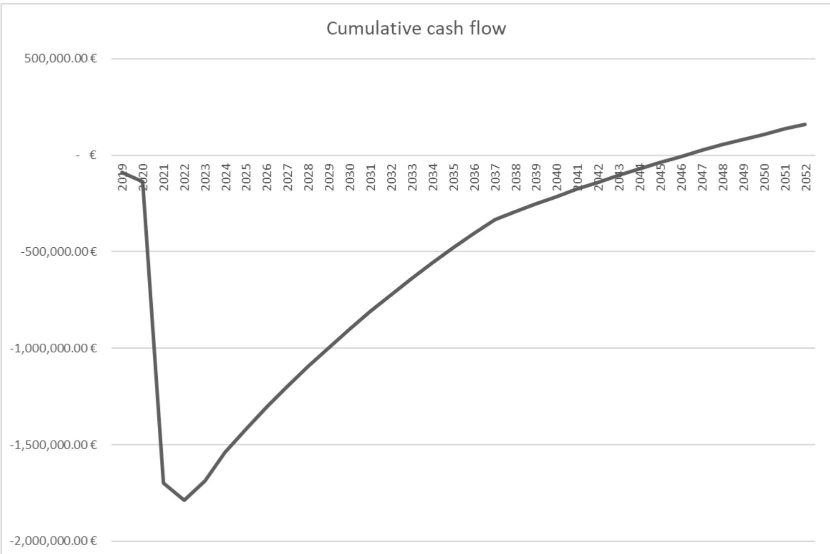
The prediction of this scenario is a return of investment only in the 30th period, with a net present value of zero. The investment is apparently risky, and one must consider that the rates are likely to be higher than those charged in other clusters in Heerlen. Rates aligned with the rest of the city would not guarantee a return from the investment within the 30 periods under analysis.

3.7.8 Scenario #8

As in the previous cases, scenario 7 is modified assuming that the Dutch subsidy for sustainable energy production SDE++ is applied.

The graph below shows the result if the variable and fixed rates charged were only 70% of the estimated maximums. The maximum rates are estimated in the same way as in the previous case (fixed adjusted for inflation, variable following the gas market trend).

Once again, the state incentive is fundamental to guarantee a more attractive investment, guaranteeing a return within the 24th period. The SDE++ contribution represents between 23 and 51% of the revenue from heat sales in the first 15 years (variable portion only). This type of investment would at the same time guarantee a (theoretically) lower tariff for domestic customers, and at the same time for Mijnwater it would mean decreasing the risk of finding itself without a customer. Differentiating the supply to more than 100 customers guarantees a secure profit, against a single customer.



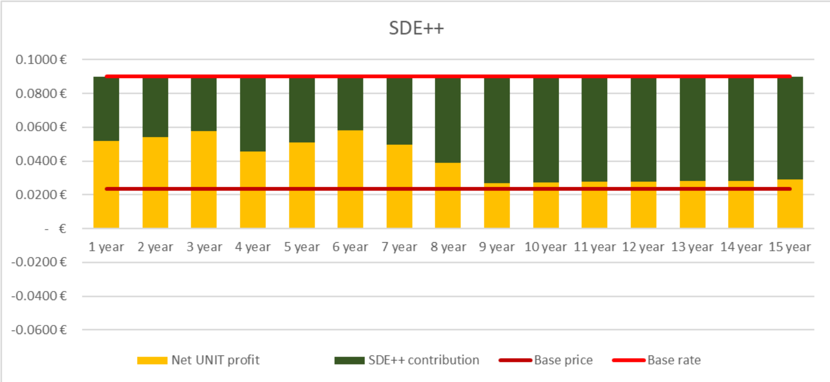


Figure 27. Cumulative cash flow and incentives for scenario 8 of the Dutch case.

3.7.9 Scenarios comparison and conclusions

The analysis of the Dutch case allows us to highlight the effects that different legislative approaches can have on the success of an investment whose final objective is to improve the environmental impact of the actors involved. Furthermore, the analysis of various scenarios provides valuable insights into the economic viability and potential returns of the investment in the district heating project connecting VDL and Mijnwater.

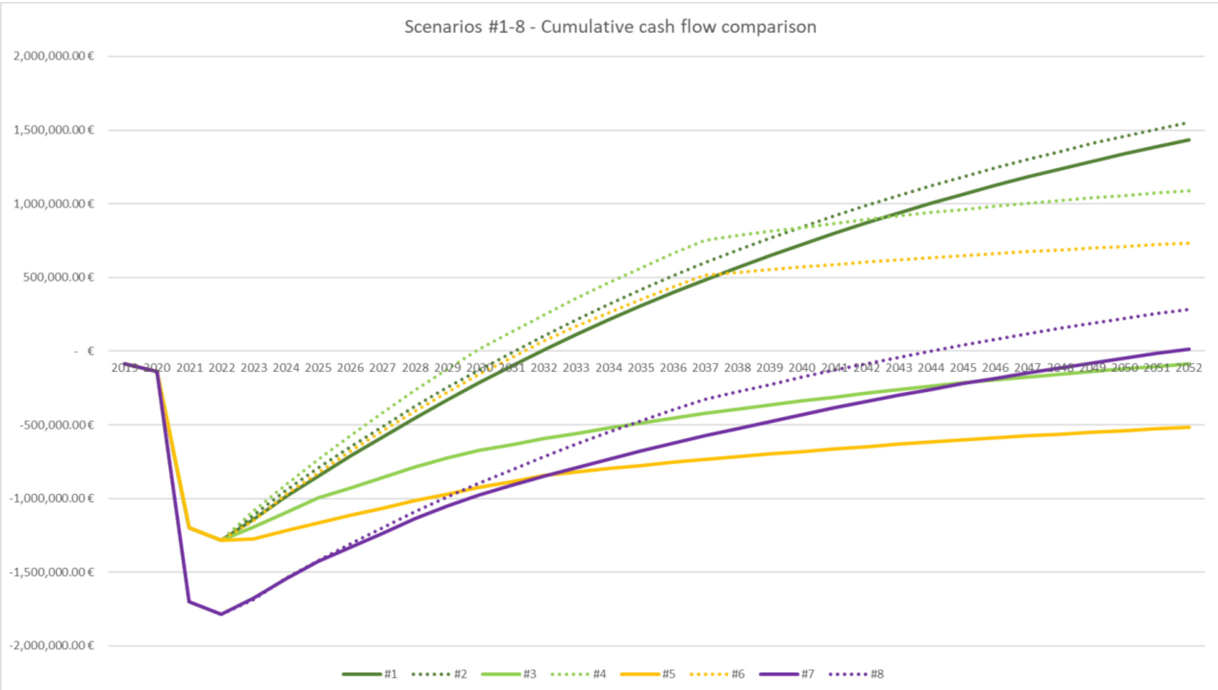


Figure 28. Comparison of the cumulative cash flows of the 8 scenarios considered for the Dutch case.

Case	User	Legislation	Prices	Incentives	AVG var. tariff	Payback period	NPV 2023
#1	Zwembad Hoensbroek	Warmtewet	Project contract tariff	no	106.33 €/MWht	**9**	1,432,077.98 €
#2	Zwembad Hoensbroek	Warmtewet	Project contract tariff	SDE++	106.33 €/MWht	**9**	1,551,764.49 €
#3	Zwembad Hoensbroek	Warmtewet	20% less than gas price	no	38.70 €/MWht	**>30**	- 87,373.57 €
#4	Zwembad Hoensbroek	Warmtewet	20% less than gas price	SDE++	38.70 €/MWht	**7**	1,089,849.11 €
#5	Zwembad Hoensbroek	WCW	Cost-dependent	no	37.77 €/MWht	**>30**	- 517,018.09 €
#6	Zwembad Hoensbroek	WCW	Cost-dependent	SDE++	37.48 €/MWht	**9**	732,958.56 €
#7	Households	Warmtewet	5-10% less than ACM maximum	no	84.04 €/MWht	**29**	15,152.15 €
#8	Households	Warmtewet	20% less than ACM maximum	SDE++	70.29 €/MWht	**24**	161,463.40 €

The first distinction to make is the one between commercial customers with a thermal connection exceeding 100kW and domestic customers, protected by the Consumer and Markets Authority.

With the commercial customer it is possible to have free negotiations, a synthesis of the interests advanced by both parties. First, pricing systems can be adopted that can guarantee the utility company mitigation of the risk resulting from variability in customer demand. In this case, in fact, the customer is contractually obliged to pay a fee of €136,000 every year for the first 1,580 MWh of heat, even if he does not even use an energy unit. This share would be enough for the utility to guarantee a return on the investment in any case within the 30 periods (the return should occur within the 24th period). It is not possible to know whether between fixed and variable quotas the new contract is more advantageous than the pre-existing situation with heating via gas boilers. Of all the scenarios, the one defined by contract is the least advantageous of all for the customer. Certainly, the customer frees himself from the responsibility of maintaining his heating systems, eliminating the risk of system breakdown. The responsibility is transferred to the supplier. For the supplier, it has been established that the fixed fee paid by the customer is entirely allocated to administration and maintenance costs. The fee of over €27,000 per year may seem high, but this is intended to also cover extraordinary maintenance or breakage of heat pumps.

Always taking the end customer into consideration, we tried to hypothesize lower rates. For example, linked to the price of gas, as now happens for domestic district heating customers, or dependent on supplier costs, as required by the new law. In both cases the result is similar, a rate 65% lower than that of the contract stipulated between the parties. In both cases, the return on the investment does not occur in the period under consideration. In both cases, the intervention of the state incentive SDE++ is necessary. By applying the subsidy in the first 15 years from the entry into operation of the system, the payback period quickly drops to 7/9 years. If a fast payback period was the main objective for the utility company, the subsidy could also be waived for the remaining 6/8 years.

In this case, no form of protection for the utility company is available. If the business customer were to unexpectedly go out of business, the supplier would be left with an unpaid investment. On the other hand, for the customer, variable tariffs that are certainly lower than the natural gas alternative would be guaranteed, as well as removing themselves from the responsibility of maintaining the heating systems. On the final result, the new law could guarantee a price variability of approximately half that of the tariffs linked to the price of gas. This allows for better forecasting of future cash flows for the supplier, and more constant costs for the customer.

What emerges is the cruciality of external investment, in this case that of a structural state incentive for all investments aimed at improving the environmental impact of energy systems. In these cases, we refer to the worst-case scenario, in which non-repayable state investments or private investments/banking institutions are not available. It is highly probable that their involvement in the planning phase would guarantee their involvement, given the growing interest in "green" investments. The involvement of more players could make the investment viable even with returns slightly higher than 30 years.

Involving domestic customers leads to interesting results.

The case of tariffs with the current law, limits on sales tariffs, link to gas prices was explored. Compared to supplying a commercial customer, the first benefit for the supplier comes from the differentiation of demand. A commercial customer is a less certain and probably more variable question. Many domestic customers represent more certain demand overall over time. In this case, the maximum tariffs defined by ACM were applied, adequately decreased by a quota between 5 and 20% to guarantee breakeven of the investment, but also tariffs in line with the national average (ACM claims that the tariffs are on average 18% lower than the maximum ones). Even in the previous cases it would be possible to obtain a similar rate and payback period with just one commercial customer. The important point of this case is to highlight how the investment is barely feasible. Since these are domestic customers, the supplier has a more constant demand, but is also strongly linked to gas prices. An unexpected drop in gas prices would push the break-even point further away, increasing the overall risk of the investment.

In the case of the new law, the result would be comparable to the discussed case of the commercial customer: the rate applied to the swimming pool reflecting the costs incurred would be divided among the customers, which in any case would be lower than the results obtained in the cases in question. Breaking even the investment would still be possible with the SDE++ state contribution, or with tariffs calculated with an increase of 45% compared to the calculated value linked to the costs incurred. With this increase, the final tariff for the customer would be halfway between scenarios 5 and 7, and a return on investment around the 29th period.

With the same fixed quota, the payback period could be further reduced, up to the 11th period, increasing the tariffs up to an average equal to that of scenario 7. With the same average cost for domestic customers, the return on the investment would go from 29th period (7th scenario) to the 11th period. The last reflection is the result of the upcoming supply act.

According to the analysis of the case in question, the Dutch Collective Supply Act could guarantee a shorter payback period for the utility company, thanks to higher cash flows in the periods immediately following the entry into operation of the system. This would not be to the detriment of the end customer, who would benefit from tariffs similar to the current case, but with certainly less variability and not linked to the price of gas, especially if this resource is not used in the system for heat production.

In conclusion, the Dutch case also demonstrates to other European cases how a law that better considers the interests of all actors does not necessarily affect the economic interest of the supplier company. Indeed, fairer and less variable tariffs are able to increase attractiveness and satisfaction for the user. Certainly, it is necessary to better clarify how ownership of the network would be transferred to the public authority at the end of 30 years. A return to the limit of this period would make the investment less feasible. The role of structural state subsidies, linked to the profitability of heat sales, play a key role, because they allow not to burden the final customer with higher tariff, increase the attractiveness of the investment, guarantee fair and distributed recognition over the time of the commitment in technologies capable of exploiting sustainable energy sources.

3.7.10 Environmental implications

Whether private customers or a single commercial customer, replacing natural gas plants would generate environmental benefits. The natural gas savings come first of all from the replacement of VDL's boilers, and to a greater extent at Mijnwater's end customers. The waste heat, adequately exploited through heat pumps, would generate 2250.77 MWh/year of heat available for customers. If you consider a natural gas boiler with 95% efficiency and a Dutch standard value of 1.88kgCO2/m3 of natural gas, you get a saving of around 506 tonnes of CO2 every year.

Consider the electricity used for heat pumps. The standard values to be considered in the Dutch case are:

- CO2 emissions from gray electricity: 0.566 kg per kWhe
- CO2 emissions from “green electricity”: 0.000 kg per kWhe
- CO2 emissions from the current Dutch energy mix: 0.400 kg per kWhe

it is possible to subtract the emissions due to the use of heat pumps from the CO2 savings obtained by replacing gas systems, but in all 3 cases the change in total emission savings remains negligible.

4 Danish case

4.1 District heating in Denmark, current situation

This section aims to present the current state of the energy system in Denmark, including the status of heating and district heating. By considering main features of the country’s current energy situation, it will be easier to contextualize selected options introduced in the business model, with related energy, economic, and environmental impacts.

The majority of the information is derived from the Danish Energy Agency's 2021 report, which is the most recent comprehensive and consolidated source of data, tables, statistics, and maps encompassing the entire energy landscape. Another source from the Danish Energy Agency is a 2017 publication centered around Danish district heating. This publication provides an overview of essential aspects, regulatory landmarks, and prospective trends. Despite ongoing advancements in networks since 2017, there have been no substantial alterations in laws and the current and future context. Therefore, the validity of the publication remains intact. Moreover, the availability of the latest data has consistently been verified through the government statistics portal, Statistics Denmark, and by referencing the complete legislative acts.

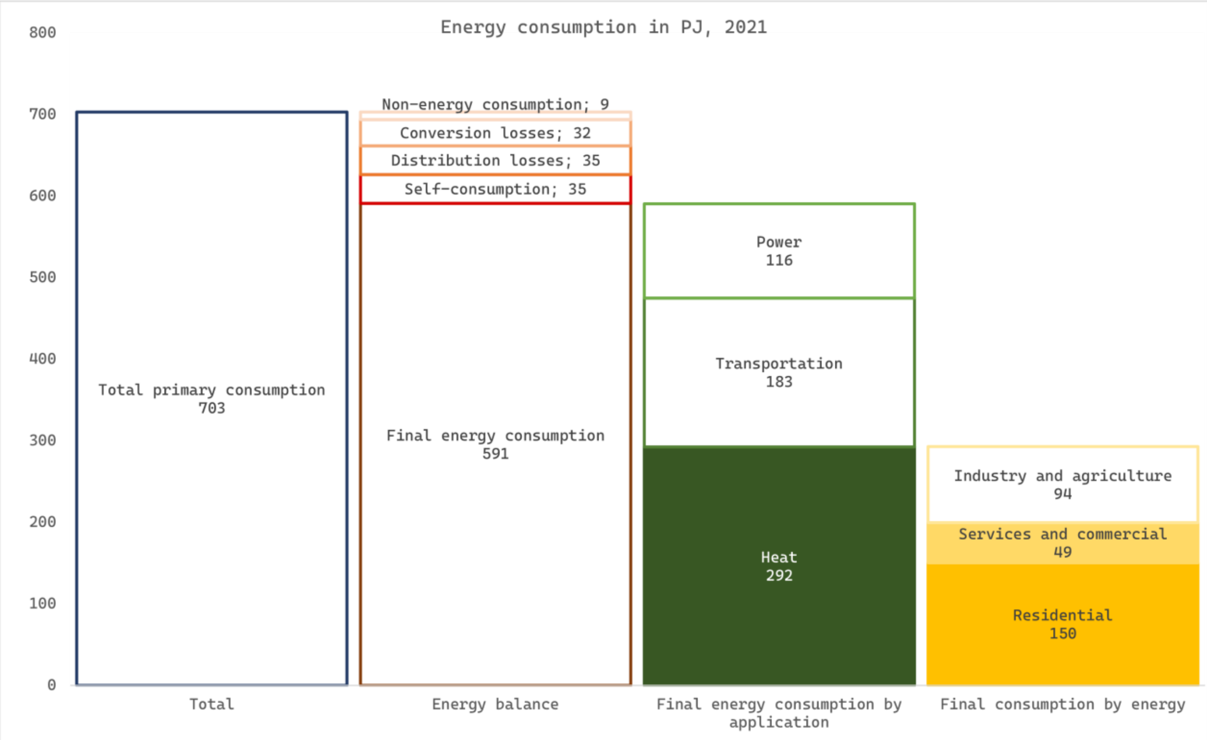


Figure 29. Breakdown of energy consumption in 2021. Source: Danish Energy Agency.

In the realm of environmental consciousness and emissions reduction, Denmark emerges as an exemplar, both within the European context and on the global stage. The country demonstrates a remarkable ability to utilize renewable and low-impact energy sources, highlighting its strong dedication to sustainable practices. Evidently, Denmark's competence is underscored by its second-place ranking in the evaluation conducted by the World Energy Council (WEC). This assessment brings together critical aspects of energy systems, summarizing the dimensions of energy security, equity and sustainability. The widespread adoption of district heating in the residential and commercial sectors has been shown to contribute to maintaining the sustainability of the entire energy sector and in aligning with long-term national and European energy policy goals. However, it would be overly simplistic to associate Denmark's commitment to the development and innovation of thermal networks exclusively with environmental goals. Since 1900, Denmark has invested in research, innovation, and strategic planning, driven primarily by economic considerations and from the awareness of the synergy that exists between energy systems.

The initial implementation of a district heating line dates back to 1903, when an incinerator in the municipality of Frederiksberg was employed to supply heat to a hospital, an orphanage, and a poorhouse. This innovative approach served the purpose of eliminating waste from the streets, addressing the limited availability of land for landfills. As early as the beginning of the last century, all new power plants were set up to be able to recover and distribute heat. Skov and Petersen (2007) pinpoint several driving factors behind the evolution of district heating in the country. These include the desire to exploit heat generated by thermal power plants, the search for stable and affordable energy sources, independence from importation following the oil crisis of the 1970s. It wasn't until the 1980s and 1990s that a heightened environmental consciousness began to take root.

In 2021, DH covered 48.9% of residential heat demand, while in the service and commercial sectors, it provided for 69.2% of demand. When looking at the number of dwellings actually connected to a network, however, Statistics Denmark anticipates that by 2023, 62.8% of dwellings will have access to hot domestic water and/or space heating through a network (Figure 5). This disparity between the share of heat supplied and the number of connected dwellings primarily arises from the geographical distribution of these networks, which predominantly serve densely populated areas. In these areas, homes tend to be smaller and better insulated, resulting in reduced heat requirements. Consequently, around 37% of the remaining dwellings still rely on individual heating technologies, despite accounting for half of the overall heat demand.

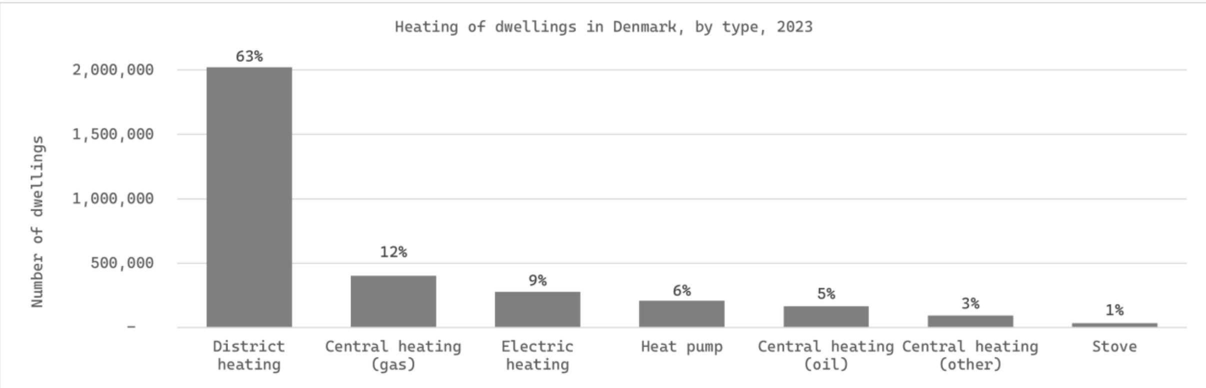


Figure 30. Dwelling heating technologies 2023. Source: Statistics Denmark.

4.1.1 Energy sources of district heating

Denmark's district heating industry boasts a commendable status when it comes to heat production. According to the Danish Energy Agency's report for the year 2021, an impressive 68.9% of the heat supplied via district heating was generated using renewable sources and non-fossil fuels (refer to Figure 31).

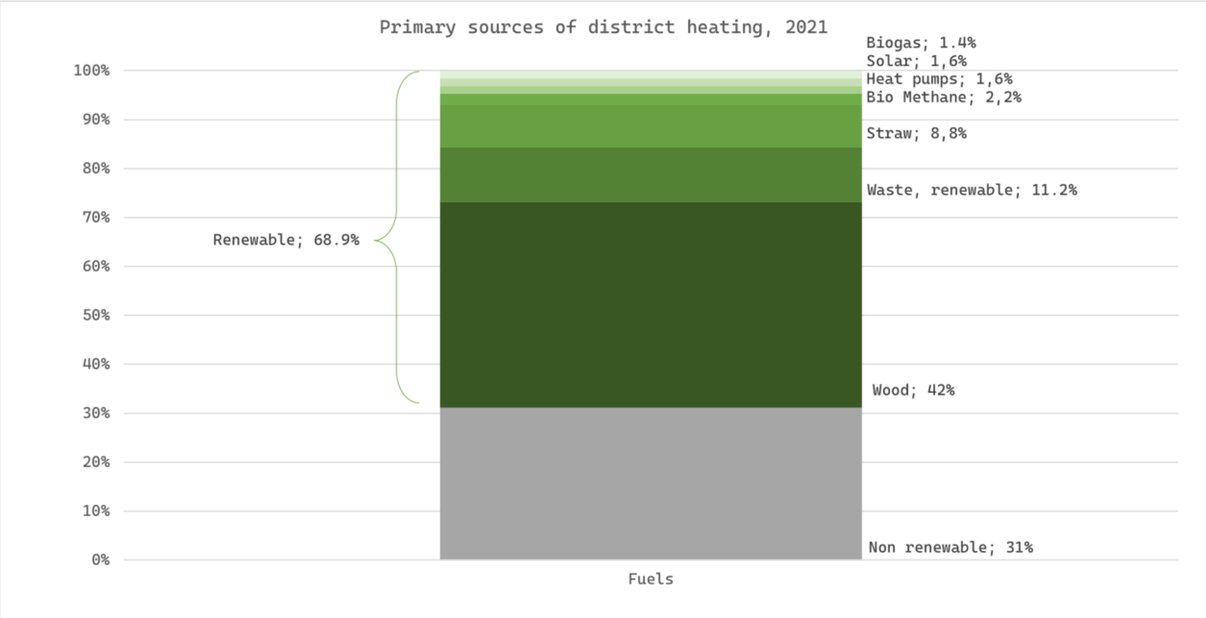


Figure 31. Fuels and primary sources in DH. Source: Statistics Denmark.

The majority of these renewable sources (90.1%) are actually biomass, which includes materials such as straw, wood, bio-oil, and renewable waste. It's important to note that emissions are still produced when biomass is combusted, but it is generally regarded as a more environmentally friendly option. This is because the amount of CO_2 released during its combustion is assumed to be equivalent to that absorbed by the plant during its growth. This cycle of CO_2 uptake and release occurs relatively quickly for biomass compared to the much longer times associated with fossil fuels. And it is this speed of regeneration that makes biomass considered a renewable energy source, as it is assumed that the amount of CO_2 released during its combustion is balanced by its rapid absorption during plant growth.

Looking at the big picture of fuels, wood material accounted for 42% of primary sources for heat production in district heating, while biodegradable waste and other forms of biomass for just over 21%. Following the United Nations principle of accountability, emissions from biomass combustion should not be considered in the energy sector of the exploiting country, but in the *land use, land-use change, and forestry* (LULUCF) sector of the nation of collection. It's worth noting that nearly 60% of the wood and straw used (excluding renewable waste) in Denmark is imported. This means that a significant portion of CO_2 emissions associated with the imported biomass is not included in Denmark's greenhouse gas accounts. More specifically, slightly over half of the imported woody biomass originates from EU countries such as Estonia, Latvia, Sweden, Portugal, Poland, and Germany, while the remainder is sourced from non-EU countries, predominantly the United States and Russia.

Consequently, emissions in land sector resulting from the combustion of imported foreign biomass by Denmark do not have a direct impact on the country's ability to achieve its 2030 environmental targets, which aim for a 70% reduction in emissions compared to 1990 levels. This suggests a commendable technological capability in Denmark to transition away from fossil fuels. However, it is essential to recognize that global emissions associated with the use of biomass still exist. For the use of wood and straw to be considered globally *impact-neutral*, it is essential that the biomass burned is replaced each time by new plantations or growth of existing vegetation. Additionally, it's worth noting that emissions linked to the transportation of these biomass sources are not accounted for in Denmark's emissions inventory. This omission makes it even more challenging to ensure that the overall net emissions remain at zero when considering the entire supply chain and its global impact.

4.1.2 Biomass sustainability and legal regulations

Until recently, there were no established legal regulations concerning the sustainability of solid biomass used for heat and electricity generation, both at the European and Danish levels. In 2014, Dansk Energi and Dansk Fjernvarme entered into a voluntary industry agreement to ensure that biomass used in more-than-20MW CHP plants meets a set of internationally recognized sustainability criteria. While this agreement does not guarantee complete emissions neutrality, it does promote wise utilization of forest resources, including those from foreign origins.

Several factors contribute to the challenge of achieving complete resource neutrality, particularly when it comes to imported biomass. The main difficulty is represented by the regulatory difference in the accounting of LULUCF emission and absorption: in fact, although the United Nations and the European Union have defined guidelines, countries are left a fair amount of freedom in choosing standard values and operating methodologies. A second significant issue is the inherent uncertainty in these calculations. Factors such as land use, forestry practices, biodiversity, plant ages, and reforestation efforts are challenging to precisely incorporate into an equation that ensures a zero net balance of emissions. This complexity is not limited to countries like the United States and Russia but extends to many EU nations, which often have insufficient and uncertain data regarding their forest management practices. Lastly, there is the matter of supplier countries aligning with Denmark's climate targets and calculation methods. As previously mentioned, biomass-related CO2 emissions must be accounted for in the country of origin. This raises concerns about the willingness of supplier countries to fairly calculate these emissions in line with binding climate goals, potentially posing an additional obstacle to achieving resource neutrality.

Despite the absence of comprehensive environmental legislation in Europe regarding the use of biomass in the energy sector, the Research Agency of the Forestry Commission has nevertheless demonstrated the environmental benefits of favoring European countries as biomass suppliers. This preference leads to a more substantial reduction in global CO2 emissions, primarily due to better results in the *life cycle assessment* parameter. The study specifically points out that countries like the United States, Canada, and Brazil demonstrate a lesser commitment to forest preservation practices. These practices include forest thinning, utilizing residuals for fertilization, afforestation efforts, and enhancing the growing stock. The comparative lack of attention to these practices in these countries contributes to the overall advantage of European biomass sources in terms of environmental impact.

The European Directive 2018/2001 represents the latest effort to promote the sustainability of biomass used for heat and power production. This directive introduces a crucial measure, as stated in Article 29(7), which establishes general criteria for verifying the origin of resources. According to this article, biofuels, bioliquids, and biomass fuels produced from forestry sources must adhere to some specific LULUCF criteria. Firstly, the origin country or regional economic organization should be part of the 2015 Paris Agreement. Moreover, they should have submitted a *nationally determined contribution* (NDC) to the United Nations Framework Convention on Climate Change (UNFCCC). This

NDC should ensure emissions and removals coverage, along with accurate accounting of forest and agricultural assets, as part of the country's commitment to reducing green-house gas emissions. Alternatively, the harvesting nation may also just possess national laws that, in line with Article 5 of the Paris Agreement, ensure proper conservation of the carbon stock and obligate a truthful LULUCF budget. Whenever the harvesting nation does not fall under the Paris Agreement, the biofuels, bioliquids, and biomass fuels can still be imported under certain conditions. This includes the implementation of management systems at the forest sourcing area level and strong documented evidence on present and long-term maintenance of resource. These systems are put in place to guarantee the maintenance or enhancement of carbon stocks and sink levels in the forest over the long term. Indeed, Article 29(7) serves as the foundation for ensuring that biomass used across various applications, with a particular focus on heat production, conforms to stringent sustainability and environmental standards. This proactive approach promotes responsible sourcing practices and contributes to the reduction of the environmental footprint associated with biomass utilization.

Examining the reception and implementation of the directive, however, reveals a multitude of voluntary schemes adopted for LULUCF calculations, leaving significant uncertainty regarding the actual environmental suitability of biomass utilization. The wide variety of voluntary schemes employed for LULUCF calculations adds to the complexity of assessing the environmental impact of biomass use, creating a degree of uncertainty about its overall environmental fitness.

4.1.3 Future trends on biomass and renewable sources for heat production

In conclusion, it should be emphasized that the use of biomass for energy purposes generally represent a climate benefit, especially when this replaces the use of fossil fuels. However, the balance is critical, and the climate damage may be greater than with the use of fossil fuels in case of poor management of the stock. Denmark introduced the use of biomass for heat production in district heating in conjunction with the oil crisis of the 1970s. Initially it was used mainly in small heat-only boilers, but with a 1993 initiative the country began to adopt more and more biomass CHP plants, converting older coal-fired ones as well. Their spread has been supported to date through exemptions, tax benefits, and economic supports.

As per the Danish Energy Agency, the utilization of biomass for electricity and heat generation has exhibited a consistent upward trend until recently, but it is now approaching a phase of stagnation, which will eventually lead to a gradual decline. A forecast was conducted regarding the usage of renewable sources and technologies up to 2030, assuming no new policies and the implementation of the European Directive 2018/2001. Wood pellet consumption witnessed growth until 2018, while wood chip consumption continued to rise until 2023. Both are projected to remain relatively stable, with wood pellets also expected to experience a period of decline. The use of wood residues, straw, and biodegradable waste appears to follow a relatively constant trajectory with a slight downward tendency. Biogas production is expected to grow significantly around 2022, followed by stabilization.

Looking ahead, it is anticipated that wind, solar, and heat pump consumption will rise, effectively filling the gap left by the decline in biomass usage. Heat production from heat pumps and electric boilers is forecasted to witness an annual increase of 15%, driven in part by reductions in electric heating taxes and the phasing out of the PSO tariff (a tariff on electricity price, implemented in 1998 to facilitate the acquisition of useful technologies to exploit renewable resources, which at the time were not competitive within the open market). Heat pumps and electric boilers are expected to make up about one tenth of total district heating production by 2030. Solar heating consumption shows an annual growth of about 10%. Non-biodegradable waste is classified as fossil fuels and is estimated to account for about 10 percent of district heating generation in 2030. In this future context, biomass utilization is expected to decrease by 10% compared to 2020 levels by 2030.

4.2 Danish legislation

Danish district heating is primarily regulated by the Heat Supply Act (*Varmeforsyningsloven*, LBK nr 2068 of 16/11/2021), which is strongly influenced by Danish environmental policies and is also impacted by the Electricity Supply Law (Elforsyningsloven).

The first law enacted on district heating dates back to 1979, and despite multiple revisions, it still makes up a large part of the current one. The great merit of Danish legislation on the subject is that it has always served as a planning guide for stakeholders, rather than a list of regulations to comply with, evolving over the years to enhance the decision-making authority of local governing bodies through continuous reviews and support materials.

As early as 1976, the Electricity supply law mandated that all new plants should adopt CHP technology to utilize co-produced heat alongside electricity generation. This decision was prompted by a 300% increase in fuel prices during that period. This mandate ensured that Denmark's district heating systems had access to highly efficient and cost-effective heat production on a national scale, creating a crucial foundation for efficient heat delivery and the expansion of district heating systems.

The Heat Supply Act of 1979 marked another significant milestone in legislation. The municipalities were initially required to assess their local heat demand and the technologies currently in use. They were also responsible for projecting future heat demand and planning the deployment of district heating networks. Subsequently, the counties developed a zoning plan that outlined the most economically advantageous areas for either continuing with natural gas supply or transitioning to district heating. Furthermore, the legislation governed the nationwide supply, a fact that had previously lacked regulation. The collaborative efforts of municipalities, working alongside local energy companies, provided breeding ground for speeding up decision-making and approval processes by higher-level public authorities. This approach streamlined the planning and implementation of district heating systems across Denmark.

Over the years, the initially rigid decision-making process and the primarily advisory role of municipalities have evolved to grant greater significance to local authorities in determining the energy infrastructure to be built and the prioritization of resources. In this regard, updates to the law by the central government have proven to be a positive evolution as they have empowered local administrations, which possess a deeper understanding of their citizens' needs. To be able to support the design of new energy infrastructure in a decentralized way, the law mandates the Danish Energy Agency to regularly publish technology catalogs. These catalogs provide stakeholders with the latest reference technoeconomic values that should be considered during the planning phase. The "Technology Data for Generation of Electricity and District Heating" catalog keeps track of existing technologies on the market as well as those undergoing economic and experimental development, thus promoting also field research.

Chapter 2 of the Heat Supply Act outlines the approval process for new infrastructure installations or significant changes. Energy utilities must submit project proposals to municipalities, which, in the absence of more specific data, rely on technical and economic catalog data provided by the Danish Energy Agency. The analysis must encompass various aspects, including socio-economic, environmental, financial-business, economic-user effects of different project alternatives. Then, the municipality approves the proposal that, in compliance with policies, rules, and local energy sector planning, maximizes the socio- economic benefit.

Public heat supply operates on the “non-profit” principle, with the law prohibiting district heating companies from generating profits. Any economic surplus must be returned to consumers the following year through lower supply tariffs.

Danish law does not establish tariffs or caps, leaving companies to determine the price for the supply. However, it does enforce cost-based pricing. In practice, utilities can only include in the tariff the costs associated with heat production and distribution. Additionally, all “necessary” costs related to administration, network expansion, infrastructure depreciation, and capital interest can be included in the fixed tariff of consumers as long as they are allowed by the legal limits.

In conclusion, Danish heating laws have consistently supported the district heating industry’s development by creating a decision-making framework that prioritizes societal and environmental benefits over business interests. Today, executive plans are developed by municipalities (together with DH companies), which are empowered at the local level to decide on energy strategies, fuels to be used, and technologies to be implemented.

4.2.1 Corporate income tax

In Denmark, corporate tax, known as *selskabsskat*, is an integral part of the country's tax system. Denmark has a relatively high corporate tax rate, which has been gradually decreasing in recent years. At the moment, the standard corporate tax rate is 22%, but in 2000 it was 10 points higher. The Danish government encourages innovation and research by offering tax incentives for companies that invest in these sectors. Furthermore, Denmark has a network of double taxation treaties with numerous countries, making it an attractive destination for international businesses. The Danish corporate tax system reflects the country's commitment to a competitive and innovation-oriented business environment, while ensuring a stable source of revenue for public services and infrastructure.

4.2.2 Value added tax

In Denmark, the general VAT rate is 25%. This rate applies to most goods and services, including food, clothing, and transportation. There are also a few reduced VAT rates, such as 6% for books and newspapers, and 8% for electricity and heating.

The VAT rate on electricity and heating in Denmark is 8%. This rate was reduced from 25% in 2021 as part of a government effort to reduce energy costs for consumers. In the analysis it is however considered at 25% from 2024, as the government has already confirmed the end of the reduction.

4.3 Climate goals

In December 2019, the Danish Parliament took a historic step by enacting the Danish Climate Act, a groundbreaking legislation with binding targets. This law not only mandates the current government, but also all future administrations to take proactive measures to combat carbon emissions. One of its key provisions is the ambitious goal of achieving 70% carbon neutrality by 2030, compared to 1990 emission levels. What's more, it aims to achieve climate neutrality in 2050, in line with European environmental goals.

Although climate and energy policies have different goals, both act toward achieving this neutrality and independence from fossil fuels. It is precisely through these policies that Denmark encourages the utilization of biomass for the generation of electricity and heat, alongside the adoption of solar, wind, and geothermal energy sources. The district heating sector plays a pivotal role in the Danish government's efforts to achieve its climate targets. In the *Denmark Can Do More 2* document, the executive outlines key actions to be accomplished by 2030. One of the primary initiatives involves municipalities revising their energy plans, with a focus on determining the potential expansion of district heating networks. According to these plans, up to 50% of homes still heated by gas and oil boilers (up to 200'000 dwellings) must be connected to district heating by the year 2028. For the remaining homes, the objective is to ensure 100% green gas availability or facilitate a transition to heat pumps as an alternative heating solution.

The Danish District Heating Association (DDHA) has put forth a compelling argument that government initiatives may fall short of meeting ambitious climate goals and has proposed more aggressive actions. Specifically, they contend that district heating, if given a central role, could be responsible for up to 44% of the total emissions reduction by the year 2030.

Their proposal is structured around three key areas:

- DDHA sets a bold target of achieving complete carbon neutrality for the district heating sector by 2030. This remarkable achievement, if realized, would contribute significantly, accounting for 33% of Denmark's overall emissions reduction target for 2030.
- Another critical aspect of their proposal involves transitioning approximately 500,000 households currently relying on fossil fuels for heating, regardless of the specific technology employed. This transition alone could contribute a substantial 7% towards the national emissions reduction target.
- DDHA also envisions the Danish district heating sector playing a pivotal role in supporting the industrial sector's transition towards sustainability. This contribution is estimated to lead to a noteworthy 5% reduction in emissions.

4.4 Business model

The examination of Denmark's experience underscores the remarkable economic viability of district heating, confirmed by its extensive implementation. Furthermore, it serves as a catalyst for broader transformations within the energy sector, facilitating a gradual shift away from fossil fuels. This transition not only promotes environmental sustainability but also enhances the nation's energy self-sufficiency and independence.

As previously mentioned, Denmark heavily depends on biomass as a renewable substitute for fossil fuels. This topic is currently a subject of debate, encompassing both the LULUCF reporting systems and the actual achievement of resource neutrality. **According to the Danish Energy Agency, Denmark utilizes approximately 27 GJ of biomass per capita annually**, with 20 GJ of this being derived from woody material. **However, the Danish Climate Council asserts that the maximum sustainable woody biomass consumption per capita should be limited to 10 GJ**. They argue that the current level of consumption is not in line with the concept of resource neutrality.

As the issue of biomass usage and sustainability continues to evolve, Europe's largest importer of biomass (Denmark) may face the prospect of having to reduce its use for energy purposes, unless it can establish clear resource neutrality under stricter European or national regulations. Should the boundary conditions in which energy utilities operate significant change, it becomes crucial for them to proactively adapt by developing innovative business models. **This scenario may involve increased investments in next-generation networks and the exploration of heat recovery opportunities from the urban environment**. Such initiatives can offer flexibility in managing heat demand effectively, ensuring that energy utilities remain resilient in the face of evolving challenges.

For the Danish case, we refer to the demonstration site located in the city of Aalborg, where heat recovery from a data center is applied. Hence, this report analyzes the scenario of recovering the corresponding waste heat and explores alternative trading schemes to ensure reproducibility. The case of Aalborg would almost seem to run counter to what has been described so far in the national case. In fact, in this city the use of biomass is totally marginal, with extensive use of waste-to-energy heat and heat recovery. The city is an interesting case because it already uses a large share of waste heat, particularly from the Aalborg Portland cement manufacturing plant. The company supplies 20% of all heat delivered to Aalborg. Nevertheless, city heating is still largely dependent on coal, which generates more than a third of the heat. In addition, only 3 plants supply nearly half of the heat, making it difficult to ensure supply in the event of a shutdown of one of them. Just in 2021, the shutdown of the city *Nordjyllandsværket* power plant (due to an accident) caused supply interruptions. Even in a city like Aalborg, exploring new sources for district heating, based on waste heat, would be crucial, for two reasons here: to differentiate heat supply facilities (increasing security of supply) and to gradually replace individual heating sources or highly polluting plants.

Table 9. DH heat energy source in Aalborg.

Source of heat	Share
Biogas	0.30%
Wood chips	1.50%
Wood and biomass	1.70%
Electricity	3.50%
Oil	5.40%
Natural gas	6.10%
Waste	16.90%
Waste heat	30.10%
Coal	34.50%

4.4.1 Electricity prices

With the goal of estimating the costs of operating heat pumps and other equipment, it was necessary to assume electricity prices until at least 2050. Energy carrier prices are highly variable, dependent on factors that are extremely difficult to predict, including supply and demand, production costs, geopolitical and environmental factors. In this case, forecasts made available by Danish electricity and natural gas transmission operator Energinet were considered. They can be considered the most reliable forecasts on the market, as they also consider assumptions about the development of the current geopolitical situation, market forecasts, and the development of production capacity and consumption. The forecast shows future spot prices for energy.

Considering the different excise taxes and surcharges from different suppliers and variable transmission and distribution charges, it was decided to calculate the final energy price in an alternative way. The Danish Statbank makes available the average energy price trends over the past few years for multiple price levels: spot prices, distribution and transmission prices, prices that include energy excise taxes, and energy VAT. The average percentage difference between the spot price and the final price (excluding VAT) was then calculated and applied to Energinet's price forecast.

4.4.2 Inflation

Inflation is also necessary data to avoid overestimating future profits. Since this is a value that is more a consequence of market dynamicity, it is difficult to predict what will happen specifically in the energy sector. For this reason, inflation has been used in order to adjust administrative, operational, and maintenance labor costs. Heat sales tariffs are only partially adjusted for inflation, specifically, only the fixed portion dependent on the customer's housing type.

The opinion of more than one source was used in this case. For 2023, the forecast of the European Commission was used, and for 2024-25 both that of the International Monetary Fund (European-level figure) and that of the central bank (HICP energy sector) were used. From 2026 to 2030, the

International Monetary Fund forecasts inflation at 2%, slightly above the pre-pandemic period. After that, the figure is expected to be in line with the 2000-2020 period (1.50%).

4.5 Key partnership

4.5.1 Data center

Northern European countries are often regarded as ideal locations for constructing data centers. In particular, Denmark holds the top position in a ranking compiled by Tech Monitor, which assessed nations based on 29 parameters. This evaluation considered variables such as energy security, IT infrastructure, climate conditions, market factors, and more. Consequently, the Danish Energy Agency projects that while data center consumption in the country currently stands at approximately 1 PJ, this figure could escalate to 35 PJ by the year 2035.

The Danish Ministry of Foreign Affairs itself is actively encouraging the establishment of new data centers, promoting the nation's 100% power grid reliability, lengthy cold seasons, commitment to energy sustainability, and low population density. Another point promoted by the Ministry to attract new data centers is the possibility of being able to integrate the cooling system with district heating networks. Despite this, to date only 5 data centers are actually able to provide waste heat for heating homes.

4.5.2 Manufacturers and technological innovators

Denmark is a world leader in district heating and has developed a dedicated DH industry with cutting-edge technologies and expertise. Danish companies involved in the DH sector cover all aspects of the supply chain, from production to installation. The Danish DH industry is so advanced and competitive due to decades of experience and a focus on high quality products. Danish consultancies have played a key role in the development of the DH sector and continue to provide assistance to authorities and utilities in planning, designing, implementing, and optimizing systems.

However, new forms of waste heat recovery, such as that in datacenters, require increasingly specific and high-tech skills, to offer alternatives to the use of biomass, which, as mentioned, is widely rooted in the country. The case of HEATFLOW represents how the Danish government fully supports innovation in the energy sector. The startup was financed by the Danish Innovation Fund and within the LIFE4HeatRecovery project it demonstrates how its developed heat recovery technology can be reliable and reduce energy consumption for data center cooling.

4.6 Cost and revenue structure

In this section, we explore various energy trading schemes between utility companies and waste heat producers, considering their implications for both customers and the environment. The initial scenario for all the models under examination is based on the Aalborg University datacenter demo case, providing a real-world foundation complete with its data, assumptions, and constraints, ensuring result reproducibility.

These scenarios encompass a range of agreements between the parties involved, with a special emphasis on those between utility companies and universities. These agreements give rise to different financial inflows and outflows, influenced by market conditions and local regulations.

The analysis takes into account the Danish district heating industrial landscape, as well as local laws and tax practices, to assess the potential flexibility within the different scenarios. These choices align with Danish and European climate goals. The analysis starts from the national and international context and goes down to the local level. Here, factors such as infrastructure, tariffs, technical and economic performance of local actors are considered, with a particular focus on Aalborg Forsyning, the utility company responsible for district heating services in the city of Aalborg.

Table 10 summarizes the most interesting considered cases and the variables in which they differ.

Table 10. Trading schemes scenarios

Scenario	Agreement between datacenter (DC) and utility company (AAFOR)	Final users	Thermal connection	Price limit
#1	DC pays AAFOR for cooling service	new connections	80 kW	No
#2	DC pays AAFOR for cooling service	new connections	320 kW	Yes
#3	"Barter agreement"	new connections	80 kW	No
#4	"Barter agreement"	new connections	320 kW	Yes
#5	AAFOR pays DC for the heat recovered	new connections	80 kW	No
#6	AAFOR pays DC for the heat recovered	new connections	320 kW	Yes

The following energy and economic data were taken into account during the development of the models, sourcing information from the most reputable and authoritative sources available.

Table 11. Main figures and assumptions

Object	Value	Source
Inflation on the long period	4.5 ÷ 1.5 %	Evaluation of inflation and energy CIHP projections from various entities at the European level. Selected on the basis of a conservative approach.
VAT (on energy)	25%	
Profit tax	22%	
Electricity costs	98 ÷ 181 €/MWh	Forecasts from the Danish TSO Energinet were used as the basis for the spot price (Energinet (June 2023) *Elpriser*). Commercial transmission, distribution, non-recoverable fees on historical average Statistics Denmark.
WACC	4%	Freeman et al. (2021) *Discounting and the Green Transition: District Heating in Denmark*. Energy Regulation in the Green Transition. Vol 1 2021. p. 98-112

Evaluation horizon	30 years	McKinsey & Company (2016) *The utility sector's efficiency improvement potential.* Published by the Danish Energy Agency
EUR/DKK exchange rate	7.45983	September 2023 exchange rate
Heat recovery share	95%	Project assumption
Network heat loss	17.17%	Average network losses recorded from 2015 to 2020 by AAFOR, 2021 environmental report
Heat pump COP	3.5	
Average annual heat consumption by household (130 sq meters)	18.1 MWh	Danish Utility Regulator (2018)
Lower heating value (natural gas)	11 kWh/m3	Danish Energy Agency (2022)
CO2 emission (natural gas)	2.1966 kgCO2/m3	Danish Energy Agency (2022)
Lower heating value (oil)	11.29 MWh/ton	Danish Energy Agency (2022)
CO2 emission (oil)	3.21 tonCO2/m3	Danish Energy Agency (2022)

Concerning the above table, it is important to stress that **a conservative value for the COP was assumed**. In the actual demo installation, average COP values above 5 are expected, thanks to the combination of the relatively high waste heat temperature achievable with the implemented thermosiphon prototype and the relatively low temperature of Aalborg district heating. Since this report has been prepared before the availability of actual demo data, a lower value, representative of more general data center installations and more common high-temperature district heating networks, has been chosen.

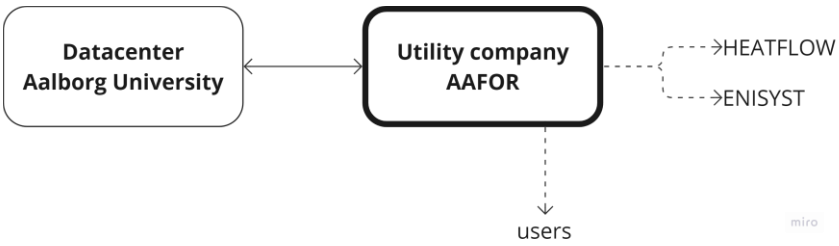
Regarding the capital investments in infrastructure, technology, plumbing, and electronic components, two different depreciation schedules were taken into account. Danish legislation provides asset owners with the option to select from these schedules, allowing for flexibility in their financial planning and asset management. Expenses can be amortized in the following way:

- Option 1 (*Afskrivningsloven*, §5C, para. 2): up to 7% of the value of the depreciable balance;
- Option 2 (*Afskrivningsloven*, §5D, para. 1): assets are included at 116% of acquisition value, up to 25% of the value of the depreciable balance, for "green" investments;
- If the value of the depreciable balance at the beginning of the accounting year is less than DKK 32,000 (EUR 4,290), this value can be fully depreciated.

The costs associated with the installation and purchase of materials were fully accounted for in the accounting year 2023. The analysis encompasses a time frame of 30 periods, aligning with the approach taken in other cases and the estimated useful life of assets in district heating infrastructure. This period is also the reference of the Danish Energy Agency. Additionally, the Weighted Average Cost of Capital rate stands at 4%, as for the investment in network expansion analysis published by the Danish Utility Regulator. The installation of heat recovery technology on servers has consistently been outsourced to HEATFLOW and ENISYST companies. This approach is based on the understanding that it would be unrealistic to expect a utility company to rapidly acquire the necessary technology and expertise for such installation. Costs were estimated as follows, always keeping the focus on the utility company supplying heat via district heating to the community:

Table 12. Main costs related to the project.

Object	Cost	Given to	Depreciable
Connection work of the prototype skid to DHN	€65,000	AAFOR	No
Material for connection of the prototype skid to the DH network	€30,000	AAFOR	Yes
Hardware components for control in switch cabinet	€30,000	ENISYST	Yes
Installation of the control system of the waste heat recovery system	€25,000	ENISYST	No
Two-phase cooling kit for 2 server racks, with evaporator and condenser heat exchangers, distribution manifolds	€111,000	HEATFLOW	Yes
Heat pump	€20,000	HEATFLOW	Yes
Hydraulic component	€10,000	HEATFLOW	Yes
Construction and installation	€30,000	HEATFLOW	No
Consultancy	€10,000	HEATFLOW	No
Demo site preparation for the prototype skid incl. electrical connections, vents, walling, lights	€26,800	AAFOR or Aalborg University	No



Costs for materials and equipment refer to the case of a heat recovery connection of one quarter of the available heat output (i.e., 80 kW out of 320 kW), and for this have been increased by a factor of between 2 and 4 in the case of a 320-kW connection.

It's important to note that while the law had previously not intervened in establishing a maximum selling price for heat, a new regulation has been introduced as of December 2021. This regulation sets a maximum sale price for excess heat, when the plant is able to absorb more than 0.25 MW. Annually, the Danish Ministry of Climate, Energy, and Utilities is responsible for defining the cap on sales to end customers for the portion of heat obtained from excess heat. This value is carefully calculated as an average of the operating and investment cost of the cheapest cases of waste heat recovery in the country. Unfortunately, this mode greatly reduces the feasibility of investments that require higher costs to implement sustainable heat sources, especially when they require a high initial investment. This cap must encompass all associated expenses, including heat procurement, distribution, investments, maintenance, electricity costs, and administrative expenses. For the year 2023, this cap has been established at 93 DKK/GJ, equivalent to 44.88 €/MWh.

The imposition of a maximum selling price serves the dual purpose of safeguarding customers from exorbitant rates and encouraging producers to explore alternative cheaper heat sources. Nevertheless, according to the Danish District Heating Association, this rule carries the potential risk of slowing down the transition to more environmentally friendly energy sources or those that would be wasted on the environment.

4.6.1 Scenario 1

Scenario 1 refers to the case where the utility does not pay for the heat recovered from the source, rather in this case it charges for server cooling service, which would still be costly to the university by any alternative method. In this scenario, heat is recovered from only one quarter of the racks in the Aalborg University datacenter. The thermal output of only 80 kW leaves AAFOR free to decide the selling price, without any price cap, relying only on the principle of cost-based pricing. The strong assumption is that the utility will totally bear the entire expense of the infrastructure work, adaptation work, technology, subcontracting the technical installation on the servers to HEATFLOW and ENISYST. In return, the company recovers the heat for free, raises its temperature since it is a high-temperature network, and sells it to customers. In addition, it receives an annual fee from the university for managing the cooling of the servers.

It is estimated, that with an 80kW heat output that is 95% recoverable and a 40kW heat pump capable of raising the temperature to 80°C, it is possible to generate about 450 MWh of heat each year. Net of grid losses, AAFOR could find itself handling just over 20 new connections (referring to the average household consumption standard of 18.1 MWh/year).

For the determination of sales tariff to the end customer, the following steps were taken, in accordance with Danish legislation, and with a view to medium- to long-term savings for the end customer:

- Until AAFOR records a negative cumulative cash flow for the investment incurred, the sales tariff is calculated taking into account the following cost items, up to a maximum of 150% of the sales price as of 2023
  - expected accounting depreciation for the current year
  - administrative cost associated with the management of new supply
  - network management cost
  - cost of operating the heat pump
- After the break-even-point (BEP) is reached from the investment, AAFOR continues to consider the same costs mentioned above, and uses 80% of the previous year's profit to lower the variable tariff in the following year
- As for the annual subscription rate, before the BEP is reached, the rate remains the same as in 2023, adjusted for the cost of expected inflation
- After BEP is reached, 20% of the previous year's profit is used to lower the subscription to new connected customers.

Applying this pricing method, in accordance with the Heat Supply Act, rates vary as shown for the end users.

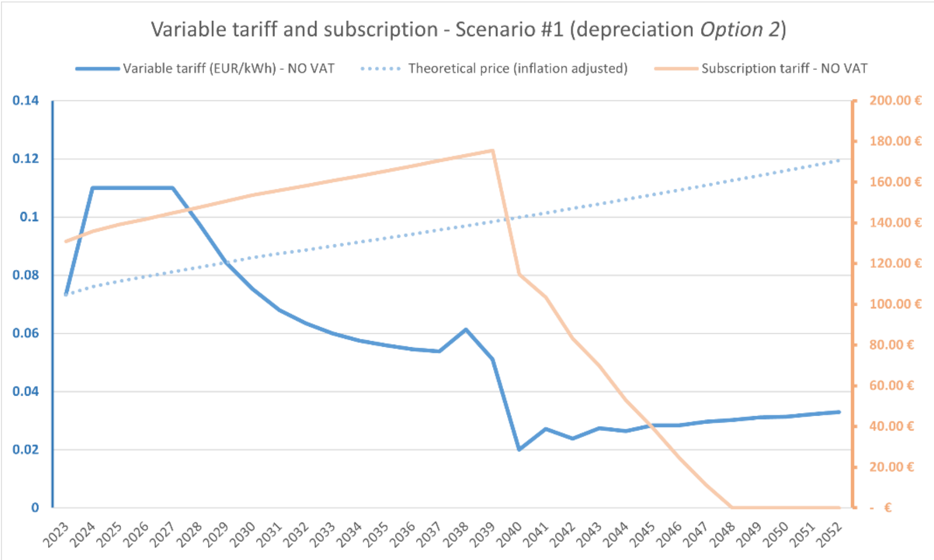


Figure 32. Tariff evolution for scenario 1 of the Danish case, under depreciation option 1.

For the 21 new connections, the fixed tariff could even go to zero after the investment breaks even. This might not be entirely realistic, especially considering that maintenance and administration costs could be less predictable.

The city of Aalborg uses a wide variety of fuels for heat production, so it is difficult to predict theoretical price and tariff trends in the coming years. However, in order to be able to make the most credible comparison between theoretical and applied tariff with heat recovery, it was chosen to adjust the 2023 tariff with inflation. Thus, for the variable rate applied, the long-term value is about 80% lower than what it could have been under AAFOR's 2023 tariff schedule (inflation adjusted).

In this and other scenarios, we assume it is possible to dedicate a different tariff to these customers than to the rest of the network. From a business perspective, it is evident that the cost savings would be distributed across the entirety of the network, allowing for a uniform tariff for all users (beyond small neighborhood-related variations). Nevertheless, this underscores the considerable potential for savings (or not) achievable through the adoption and replication of the business model. In this case, there would be a tangible cost reduction starting 6 years after the initial investment.

As evident in the following Figure, the BEP is reached in 17 periods. After that, profit tends to zero, so as to comply with the Danish utilities' policy of non-profitability.

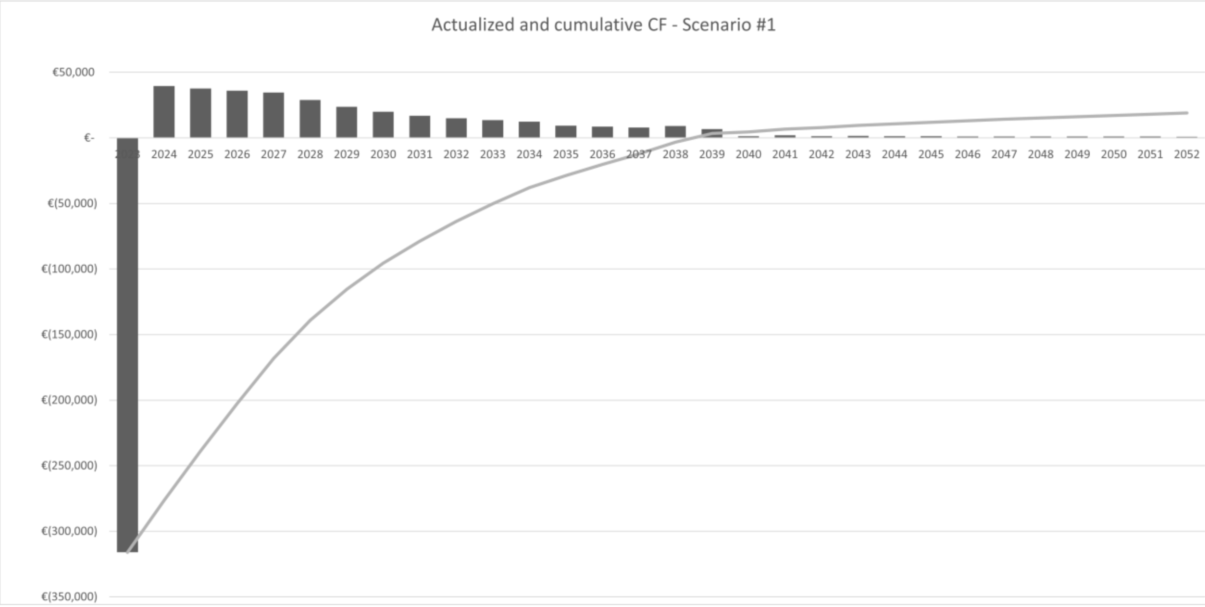


Figure 33. Utility actualized and cumulative cashflow for scenario 1 of the Danish case.

In this case, *Option 2* was chosen for depreciation (with a 25% share of the remaining balance at the beginning of the accounting year), as it maximizes the overall benefit for the customer. In the case of *Option 1* with a rate of 7%, breakeven would have been achieved 5 periods later, and user variable tariff would never have been higher than in 2023, as evident from the following Figure. Despite this, the overall cost to customers over the 30 periods considered would be 10% higher than under cost amortization *Option 2*.

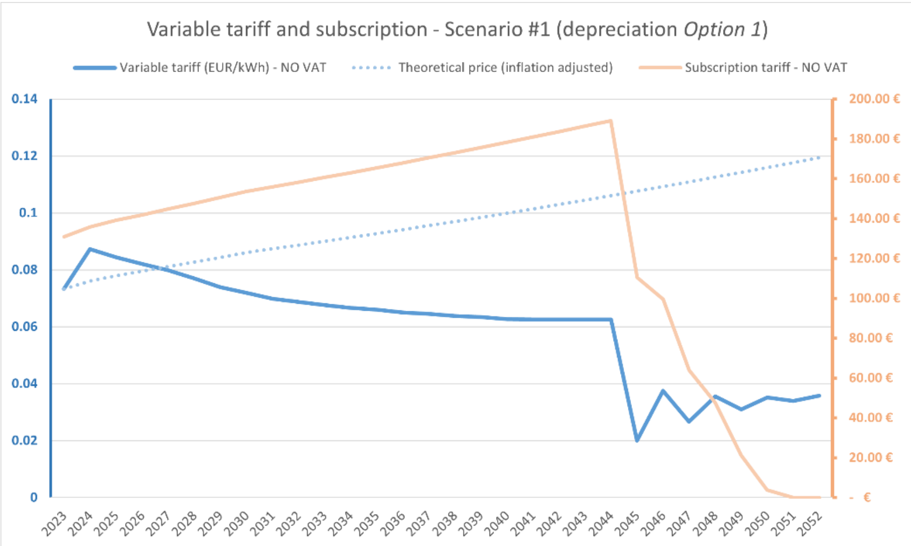


Figure 34. Tariff evolution for scenario 1 of the Danish case, under depreciation option 2.

In the outlined scenario, the economic contribution from the university (data center) in return for the cooling service plays a pivotal role. In this scenario, a cost was presented to the university that is 60% of what they would typically incur with a CRAC (Computer Room Air Conditioning) cooling system. On average, the university will pay about €8,700 per year. Up to the BEP is reached, this revenue contributes to the incoming cash flow, accounting for a percentage ranging from 25% to 60%. After that, this figure contributes to lowering the tariff for end customers.

In conclusion, Scenario 1 highlights a symbiotic relationship between AAFOR, the university, and end customers in the use of server-generated heat for cost-effective heating. AAFOR, while initially covering infrastructure and technology expenses, maximizes savings and redistributes benefits through wise pricing strategies. The breakthrough, marked by the BEP, marks a change in pricing dynamics, combining savings for customers and sustainability of this business model. It emphasizes not only the potential for substantial cost reductions for all users, but also the positive impact on the environment, considering that newly connected customers replace an individual fossil fuel heating method. The comparative environmental analysis will be presented at the end of the scenarios.

4.6.2 Scenario 2

Scenario 2 still refers to the case where the utility is paid for the cooling service by the datacenter. In this scenario, heat is collected from all racks by the university datacenter. In doing so, a thermal output of 320 kW is achieved, above the 250-kW set by law as the limit for which the utility is free to set the selling price. In this case, the entire heat share is subject to a sales price cap, defined annually by the Danish Ministry of Climate, Energy, and Utilities. Precisely because of its dependence on instances of heat recovery throughout the year, its value may change. In the absence of definite data, it was decided to consider the value in 2023, adjusting for the cost of inflation. How this limit may change is not well predicted. In the long term it may even decrease, as a result of economies of scale and increasingly cost-effective technologies for waste heat recovery in urban environments. In any case, as of today, this limit may already undermine the feasibility of an investment in heat recovery in a datacenter, as the high technological content entails certainly higher implementation costs.

Again, the assumption is that the utility will totally bear the entire expense of the infrastructure work, adaptation work, technology, subcontracting the technical installation on the servers to HEATFLOW and ENISYST. In return, the AAFOR recovers the heat without paying, raises its temperature since it is a high-temperature network, and sells it to customers. In addition, it receives an annual fee from the university for managing the cooling of the servers.

It was assumed that heat is always 95% recoverable and that a properly sized heat pump is still able to bring temperatures up to 80°C, generating a total heat of 1.7 GWh. Continuing to consider 17% network losses due to transport, about 83 new customers could be connected to district heating of Aalborg (referring to the average household consumption standard of 18.1 MWh/year).

The following choices were made in determining the selling price to the end customer:

- As long as AAFOR records negative cumulative cash flow from the investment, the sales tariff is maximized at the price cap for the year.
- After the break-even point is reached by the investment, AAFOR minimizes the tariff, choosing between a total cost allocation on kWh sold or price cap. The costs also consider the earnings due to the cooling service and any profit made in the previous year.

- As for the annual subscription rate, before the BEP is reached, the rate remains the same as in 2023, adjusted for the cost of expected inflation.
- After BEP is reached, 20% of the previous year's profit is used to lower the subscription to new connected customers.

Applying this pricing method, in accordance with the Heat Supply Act, rates vary as shown for the end users.

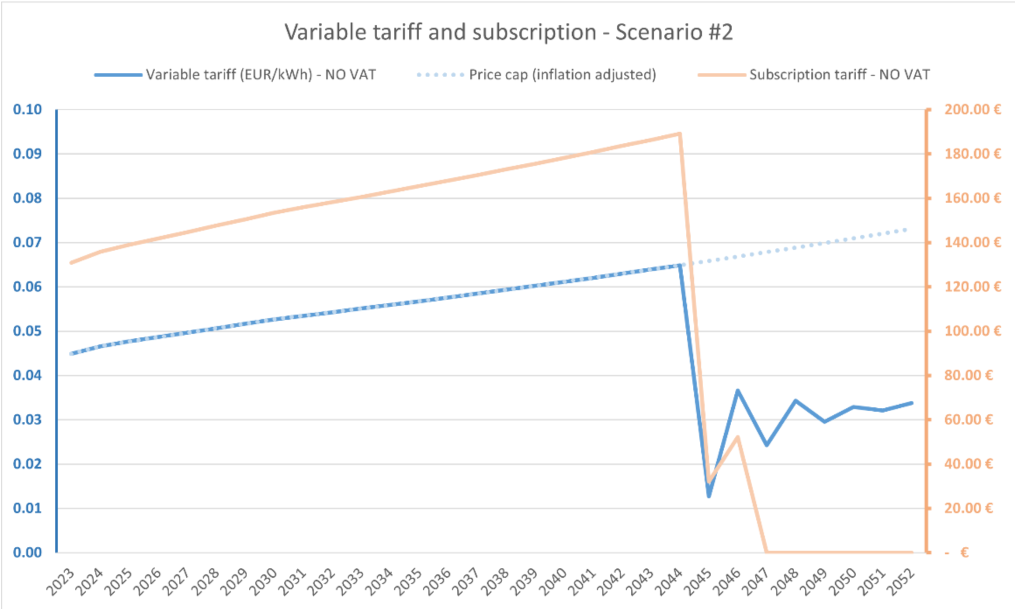


Figure 35. Tariff evolution for scenario 2 of the Danish case.

Once the BEP is attained, the zero-profit principle swiftly causes the subscription fee to decline to zero. Subsequently, the customer is left with the variable tariff, which, immediately after recovering the initial investment, is solely based on the incurred costs. It immediately turns out to be the most economical choice when compared to the price cap, which is why the price of selling heat will remain well below the price cap from then on. In particular, in the long run, the selling price will be only 45% of the price cap (inflation adjusted).

An attempt was made to consider selling heat at a price below the price cap right from the start, perhaps based on the current year's heat production cost (which would fall below the price cap as early as 5 years post-investment). However, this approach did not lead to the attainment of the BEP within the 30 periods under analysis, making the investment less appealing. It is worth noting that the chosen approach should not pose a legal issue, and the selling price would still be less than the rates currently charged by AAFOR.

As shown in the figure below, the BEP is reached in 22 periods, 5 more than Scenario 1 without price cap. After that, the annual profit tends to zero, given the unprofitable policy for Danish utilities.

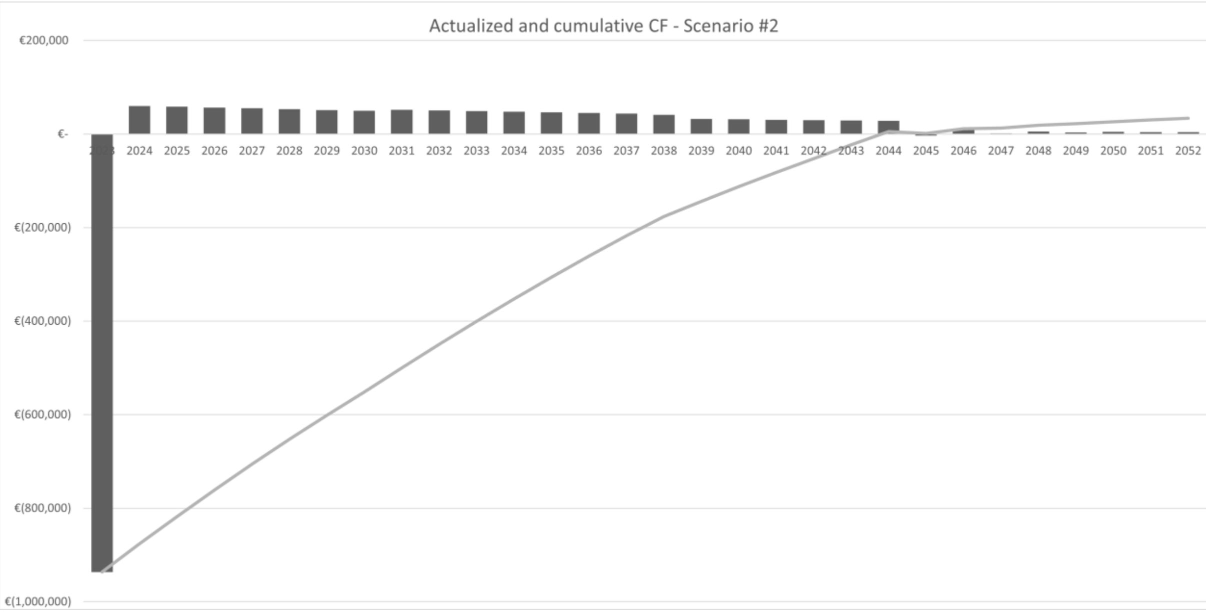


Figure 36. Actualized and cumulated cashflow for the utility under scenario 2.

Also in this case, Option 2 was opted for in terms of depreciation, aiming to expedite the return on investment and optimize overall benefits for the customer. During the initial 5 years post-investment, the company records a negative net profit primarily due to accelerated depreciation. However, this should not cause concerns about financial sustainability and the ability to generate value, especially given the consistent positive cash flow from the second period onwards. If the negative net profits were to present an obstacle to the investment, there is the alternative of choosing Option 1 for asset depreciation. In this scenario, there would be no negative net profits, and the break-even point would be achieved just 2 periods later than in Option 2. Again, the chosen case (Option 2) should ensure a better benefit (lower costs) for end customers over the 30 periods.

In conclusion, Scenario 2 unfolds a complex interplay of factors, particularly the legal framework defining the sales price cap, influencing the viability of heat recovery from data centers. The regulatory limit necessitates meticulous pricing strategies and cost management, emphasizing the delicate balance between cost-efficiency and profitability. Despite the potential obstacle posed by this constraint, the envisioned symbiosis between the utility and the datacenter remains promising. The case also underlines the adaptability and foresight required to navigate evolving market dynamics. As mentioned above, the change in the price cap is difficult to predict, and the close link to inflation unrealistic. Assuming that the price cap remains the same as in 2023 for all periods, return from investment would not be possible within the 30 periods, but shortly thereafter. If the price cap were to even fall, the investment would be totally unattractive. Thus, the price cap could be extremely dangerous for the profitability of the investment, and thus disincentivize heat recovery from the urban environment. It is precisely the volatility of this price cap (recently introduced) that undermines the evaluation and design phase.

	Scenario #1	Scenario #2
Delivered heat yearly	384 MWh	1,537 MWh
Avg. cooling service cost	8,784.69 €/y	33,782.05 €/y
Price cap	No (all cost-based pricing)	Yes (2023, inflation adjusted)
New connections	21	85
Average variable tariff	33.4 €/MWh	45.8 €/MWh
BEP	17 periods	22 periods

4.6.3 Scenario 3

Scenario 3 has been named "barter agreement" due to the fact that no economic exchange now takes place between utilities and datacenter during operations. Now, AAFOR still bears the burden of all operational costs and initial investment, except for costs strictly related to the university, such as preparing the site to accommodate the skid and electrical and plumbing connections relating to the university building. The division of costs reflects the benefit that both will derive from the investment. The scenario considers the case of heat recovery from only one quarter of the datacenter (80 kW thermal power).

Therefore, in this case, the price cap does not apply. Otherwise, all the assumptions of Scenario 1 remain valid, such as the amount of deliverable heat, the number of new connections (21), and the pricing scheme. Regarding the latter, below is the graph showing the price trend for customers. To protect users from excessive heating costs, the tariff will never exceed 160 % of the 2023 tariff. Unfortunately, with this simple pricing scheme the BEP is reached one period beyond the 30 periods considered. For this, 20 €/MWh is added to the variable tariff for 6 periods between 2028 and 2033 (red area), justifiable by the investment incurred. In the first 10 periods the tariff is higher than that of 2023 by approximately 40% on average. Over the long term, the variable tariff settles at less than 50% of the theoretical 2023 price adjusted with inflation.

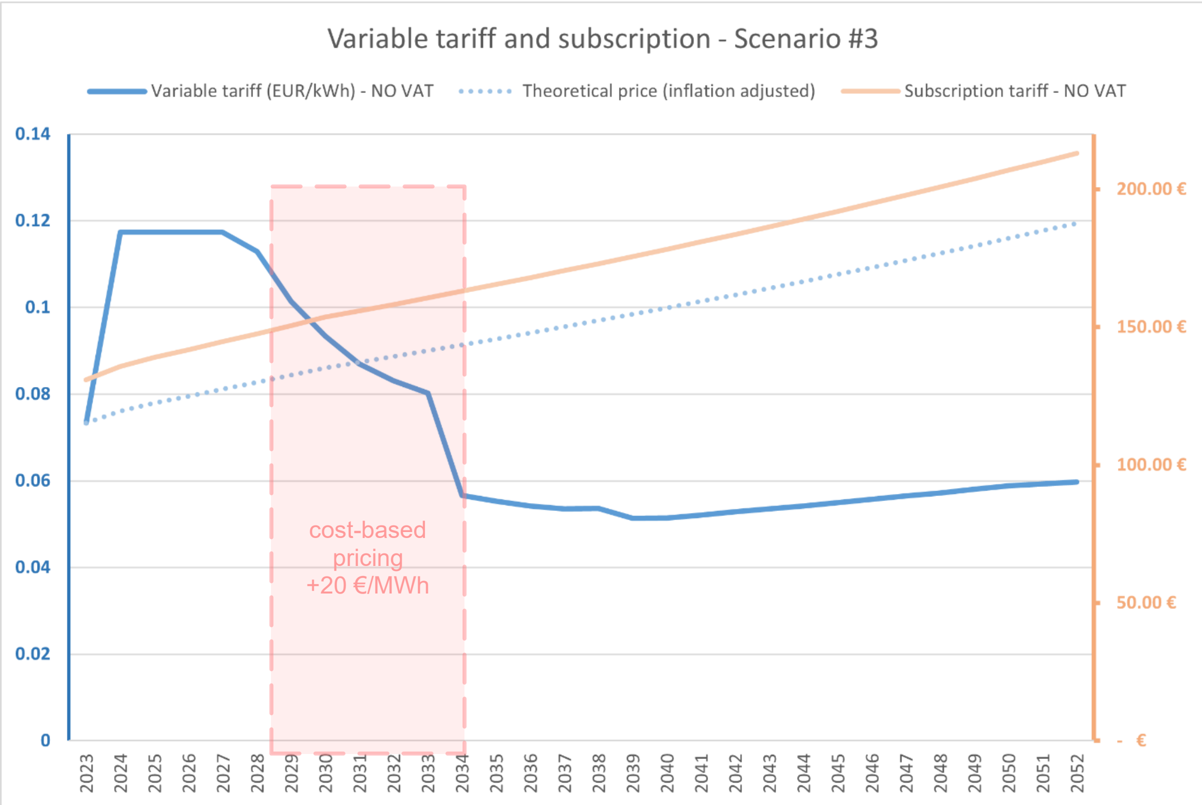


Figure 37. Tariff evolution for scenario 3 of the Danish case.

A disadvantage of this scenario compared to the previous ones is that no decrease in the subscription fee for the connection is expected. Before reaching the BEP, customers could see an increase of up to 60% in the subscription fee and fixed component per square meter compared to 2023 rates, due to inflation. The fixed fee would in fact constitute a key share of revenues for AAFOR, in this case up to a maximum of 25%. However, taking stock of the entire time frame, an overall savings for customers of 10% is expected on heating.

Recall again, that the analysis considers the distribution of costs and savings on new customers only, and not on the entire network. This is to emphasize how operational agreements and choices affect rates and customer service. More realistically, the entire Aalborg network could bear the costs and enjoy the benefits of the investment.

Given these assumptions, the BEP is attained by the 30th period. When compared to Scenario 1, this is relatively less attractive. However, it's important to note that barter agreements, a common practice in heat recovery cases by parties, ensure a broader distribution of risks and the overall benefit among involved parties. In this case, for example, the university would be exempt from paying the costs for the cooling service in the future, in exchange for taking on part of the risk borne by the utility.

4.6.4 Scenario 4

Scenario 4 starts from the same assumptions as Scenario 2, but still involves a "barter agreement" between the parties, as in Scenario 3. The heat recovery system from the data center is therefore 320 thermal kW. The temperature is subsequently increased by a heat pump, adequately sized for heat recovery. As can be seen from the figure, with the same assumptions as scenario 3, AAFOR would not recover the investment in the periods considered. This is mainly due to the cap on energy sales, which forces the company to sell this heat at a price that is even lower than the current average tariff applied by AAFOR for the market.

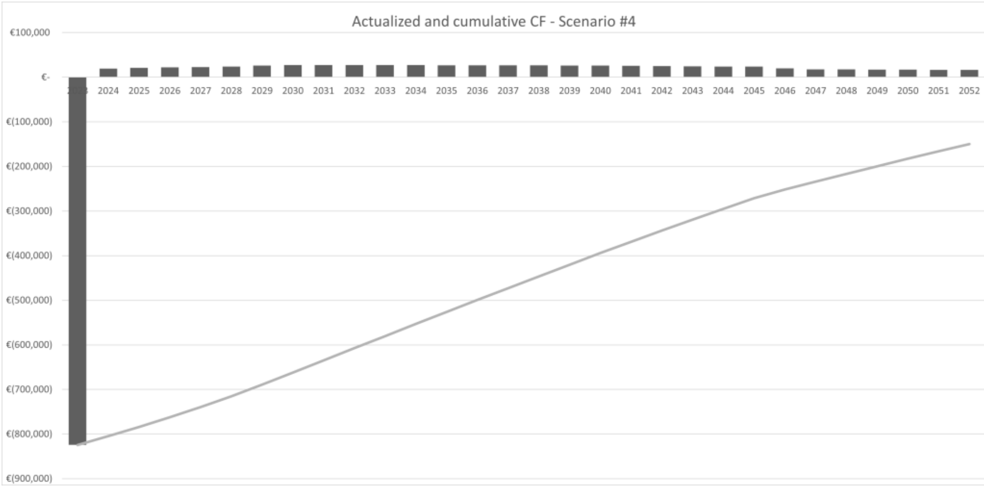


Figure 38. Actualized and cumulated cashflow for the utility under scenario 4.

Some options have been evaluated to make this type of agreement competitive for the utility company, as this specific case could be highly replicable due to the significant benefits achievable for all parties involved (heat producer, utility company, consumers).

The law allows setting a higher price limit in the first 3 years after the investment, with a corresponding decrease in the following 3 years. While this helps accelerate the initial depreciation of assets, it fails to increase the attractiveness of this scenario for the utility company.

The legislation empowers the Danish Energy Agency to provide specific projects with individual price caps exceeding the legally defined limit. However, the criteria for granting such exceptions, defined as "special cases," lack explicit delineation in the regulation. In particular, the regulation specifies that cheaper alternatives to the project under discussion must be carefully evaluated before granting such an increase in the selling price. Obviously, these alternatives must be economically viable for the utility company, geographically proximate, and ensure equal or enhanced supply efficiency. Since it is not possible to carry out this analysis, it is assumed that this increase is granted. To achieve a return on investment within the 30 periods under analysis, it would be sufficient to increase the sales tariff by €45/MWh for the first 3 years or by €22.50/MWh for the first 6 years. This latter option would result in an increase of €400 per customer per year. Additionally, more dynamic pricing increments could be explored, such as tied to specific consumption thresholds, incentivizing energy savings among households.

A second viable option entails an increase in the fixed subscription fees from the current €130 average charged by AAFOR to a new average of €220 (even today different customers, fall into different subscription brackets based on household size, this value represents only the average). Afterward, the subscription would increase as it does now due to inflation. This case would also allow reaching the BEP by the 30th year, ensuring a better distribution of the price increase. Importantly, these adjusted subscription prices would remain in alignment with those of other Danish district heating operators, upholding competitiveness within the industry. Additionally, any increases aimed at accelerating return on investment would be reasonably distributed across all customers in the network.

Another possibility, which would shift more costs to the heat producer rather than the end customers, would be to allocate the initial investment costs differently. Specifically, this could be achieved by taking into account the fact that the university would receive cooling services at no cost, with significant savings on existing cooling systems. For instance, by directly transferring the cost of purchasing the HEATFLOW technology to the university, a significant change in Scenario 4 would be achieved. AAFOR would reach BEP by the 18th period. Similar to the other scenarios, customers would enjoy substantial tariff savings as early as the next period. At the end of the considered timeframe, the fixed tariff would fall by 60%, and the variable tariff would be 30% lower than the legal limit.

The university would now incur costs of about €600,000, and would return the investment in 19 years, thanks to savings achieved on cooling. Agreements with intermediate terms on cost sharing would also be feasible.

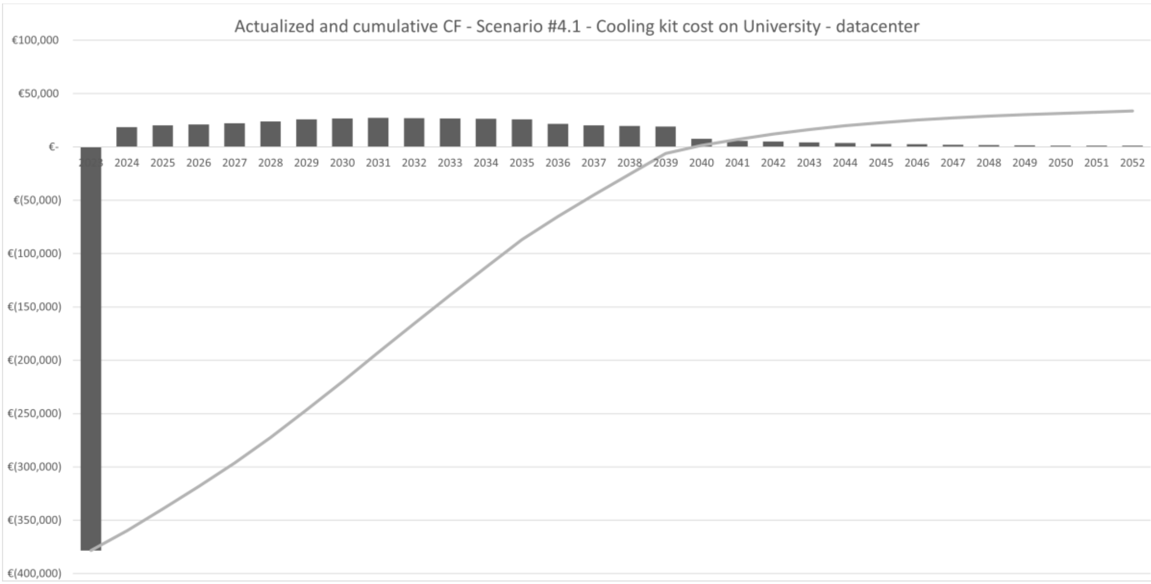


Figure 39. Actualized and cumulated cashflow for the utility under scenario 4, with cooling kit cost assigned to data center.

4.6.5 Scenario 5

The fifth Scenario explores the possibility of an arrangement under which the datacenter sets itself up as an actual producer of heat and sells it to the utility. This possibility would seem unlikely in the case under analysis, since it is a datacenter with relatively little thermal power and considering the university as an entity that pursues logics other than the unique profit one. Still, it is worthwhile to hypothesize such a configuration and test its feasibility having in mind larger and for-profit datacenters.

The assumption for this scenario is the 80 kW connection. This case is interesting considering that it does not involve the imposition of the price cap. In fact, the purchase of heat by the utility would have to be covered by the maximum selling price to the end customer, making the pursuit of this type of business model even more risky and critical.

On the other hand, the datacenter here views the sale of heat as a fundamental aspect of its operations. Consequently, it regards heat recovery technologies from HEATFLOW as strategic assets to be seamlessly integrated into its infrastructure, aiming to generate additional value from its operations. This is precisely why in Scenario 5, the investment risk is transferred to the data center, given that the sale of heat would serve as the revenue stream essential for repaying the investment cost. It is crucial to take into account that if the sales contract were to terminate, the data center would possess a potentially profitable heat recovery infrastructure that remains unused. To mitigate this risk, a long-term agreement is envisioned, potentially encompassing penalty clauses in case of termination by the utility company within a specified period. These penalties could help cover the investment costs incurred by the data center. In this case, the representation of the relationships between the parts is better specified in the following Figure.

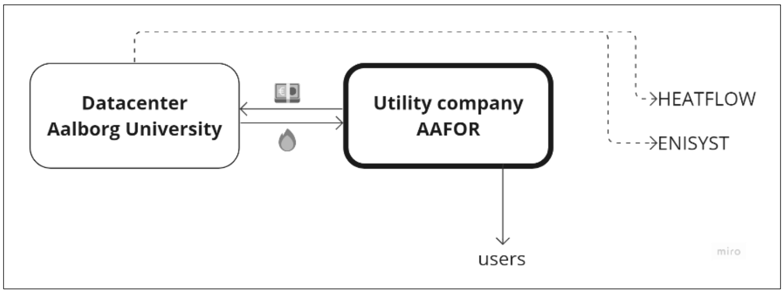


Figure 40. Utility-datacenter relationship in scenario 5.

The dynamic pricing method based on marginal cost would be suitable to define the optimal sales price of heat from the data center. Through the proposed method, AAFOR would purchase heat from the cheapest source in the market and then turn to increasingly expensive sources as heat demand increases. In this way, all heat producers would be paid according to the marginal cost (hourly or daily) of the most expensive production technology active at that time. By "optimal sales price", it is meant that price which would allow all the heat available annually to be sold at the highest possible price. It is not clear at this time what the heat purchase agreements are between the utility and the major heat producers in Aalborg, nor what the seasonal heat demand of the users is. Therefore, it is not possible to perform a seasonal demand analysis and predict at what rate AAFOR would buy all the heat offered by the datacenter. However, the assumption remains to connect new customers corresponding to the new heat supply. It is also assumed that the datacenter offers heat at the average price at which AAFOR has produced/bought heat over the past 3 years. This value is 50.30 €/kWh with a "premium" of 5 €/MWh, for a final cost of 45.30 €/MWh. This cost is fixed for the duration of the analysis, assuming a sales contract covering the entire analysis period.

The cash flow forecast for the utility is first analyzed. In this case AAFOR would no longer have to bear all the costs of the initial investment, but would only bear the burden of connecting the network to the datacenter skid. As in the previous scenarios, the sale price of heat to the end customer reflects the costs of the accounting year, after the BEP is reached, any profits made in the previous accounting year are subtracted from the sale price. Of course, the price first reflects the cost incurred in purchasing heat from the datacenter.

In this case, Option 1 was chosen for depreciation, as it is unclear whether the investment of simply connecting to the skid can be considered "green". It is the datacenter that promotes an investment that can truly decrease emissions. Below is the forecast of possible fixed and variable rates.

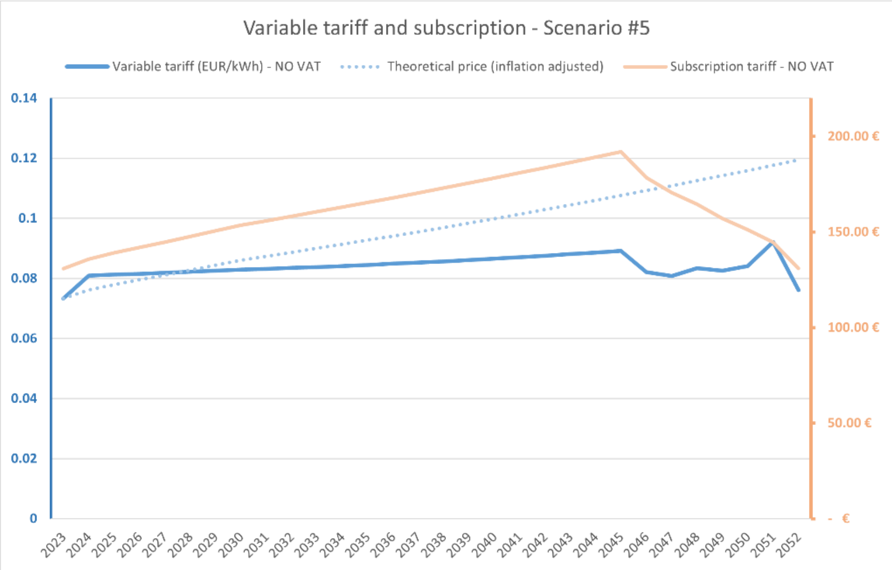


Figure 41. Tariff evolution for scenario 5 of the Danish case.

In this case, reaching the BEP (23rd period) hardly seems to affect variable rates, which receive only a small drop. Actually, if the tariff is assumed to be fully sensitive to expected inflation, this mode of pricing would cancel out the effect of cost-of-living increases. The fixed tariff is also sensitive to reductions due to profit. A sharp decline from the return on investment is observed in this case. Following is the cash flow analysis for the utility.

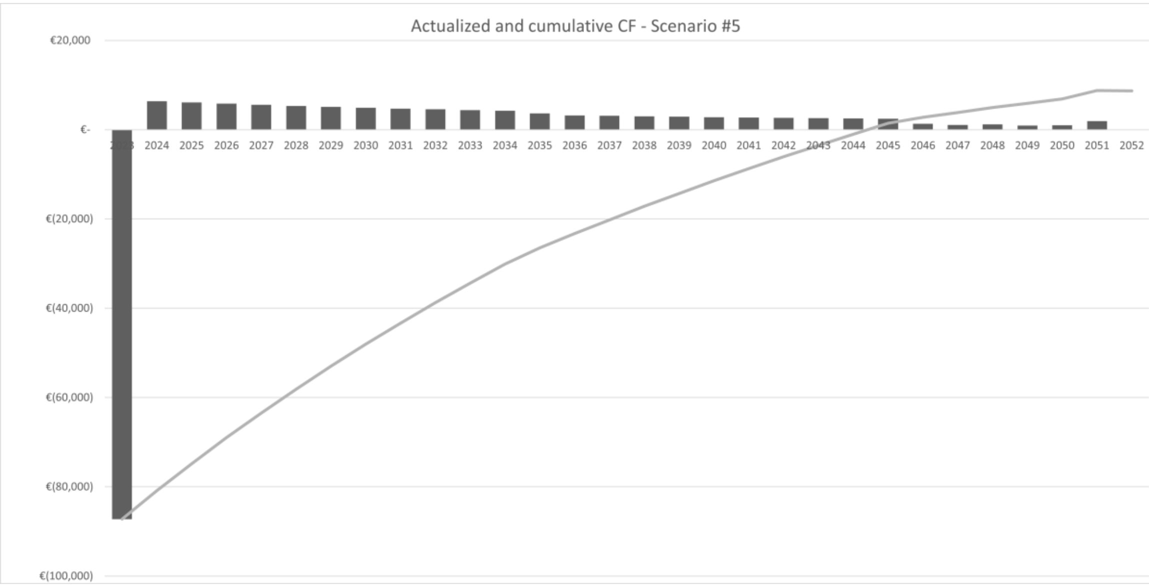


Figure 42. Actualized and cumulated cashflow for the utility under scenario 5.

The BEP is reached at the 23rd period. It is worth mentioning how in this case the utility's investment would be less than €100,000, compared to over €300,000 in Scenarios #1 and #3. The risk to the utility would appear significantly reduced.

In this case, the risk is more shifted to the datacenter. That is why the convenience for heat producer must also be evaluated, because otherwise the datacenter would not invest in such technology without an economic return. The NPV method was also chosen for this analysis, considering the same evaluation parameters as in the utility company case. Below is the discounted cash flow analysis for the datacenter.

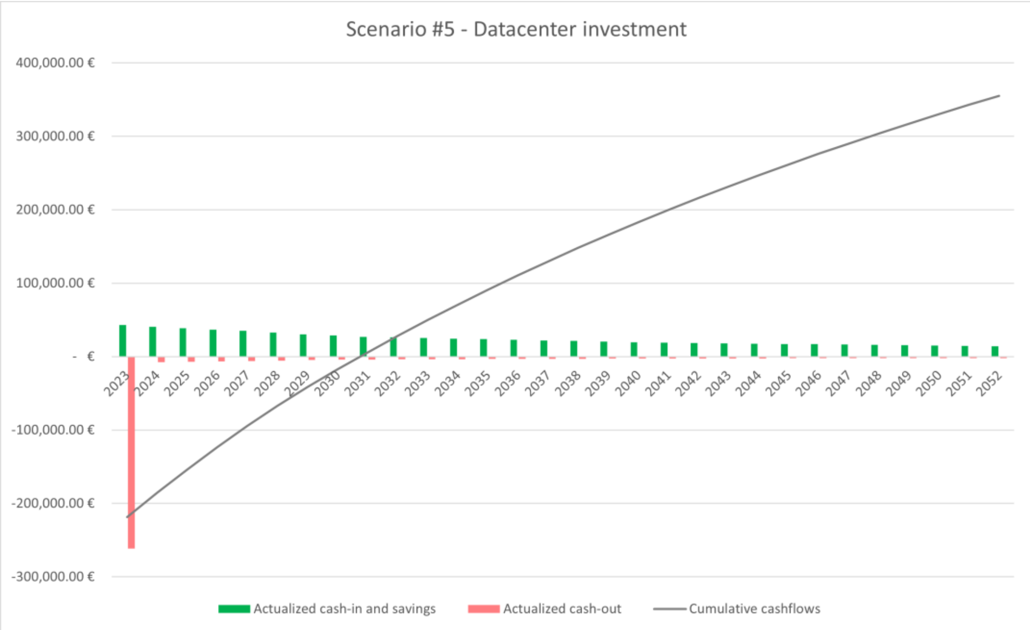


Figure 43. NPV and actualized and cumulated cashflows for the datacenter under scenario 5.

This investment is certainly convenient for the data center. The operational costs of running the system and the heat pump would be covered by the sale of heat and the savings achieved by replacing the old cooling system. As for Scenario 1, the consumption of a CRAC system for the cooling of a corresponding data center of equal consumption was examined. Most of the earning therefore represent the *avoided cost* thanks to the new cooling system, in addition to the profit obtained from selling the heat to the utility. The NPV is expected to exceed €350,000 over the period considered.

In conclusion, this scenario appears feasible and profitable for both parties. The risk of the investment is almost completely shifted to the data center, even if the potential profit already occurs after 9 periods. Unlike other business models, this one has a key disadvantage from a social point of view. In this case, the potential gain, as well as the risk, is transferred to the data center. The utility then becomes a "customer" of the heat producer, and simply passes on the cost of the waste heat to the end customer, in line with Danish legislation. Most of the generated value becomes profit for the data center, which has no interest in redistributing on a lower heat sales tariff. A great price saving opportunity is therefore lost for the end customer.

The shift towards a dynamic pricing model for the purchase of heat based on marginal cost, as examined in this case, however, has the great advantage of generating competition among heat producers, who would consequently lower their tariffs to cost marginal energy production. One possibility is therefore to move towards a dynamic pricing model also for end customers on an hourly basis, which reflects the purchase and production of this heat. In conclusion, by examining this type of general market logic, the value could be partly transferred back to the end customer.

4.6.6 Scenario 6

To complete the framework of analysis, the sixth and final Scenario is analyzed. This case combines the assumption of extending heat recovery to the entire datacenter and the type of arrangement of Scenario 5.

The approach remains the same: the view of a dynamic price and the desire to remain competitive leads the datacenter to offer its heat at the average price of heat production by AAFOR, minus a premium, for a total of 45.30 €/MWh. Again, this maximum heat purchase price is set by contract for the entire period under analysis.

In this case, the heat recovery plant over 250 kW obligates the imposition of a cap on the selling price to the end customer. It becomes immediately apparent that the cost of heat alone for AAFOR from the datacenter is already greater than this cap. Given the difficulty of predicting how this limit will evolve over the next few years, the datacenter remains reluctant to undertake a potentially non-beneficial investment.

It is hypothesized, however, that the data center considers this investment as a strategic resource, since it would guarantee better cooling performance, lower overall energy consumption, and therefore also benefit from a better reputation and image perception in the eyes of the public. A possible strategy could be to lower the sales price, so that the utility finds it convenient to purchase heat, invest in connection and connect new customers. This value would be lowered to 27.50 €/MWh, and in this way the utility anticipates subsequent cash flows.

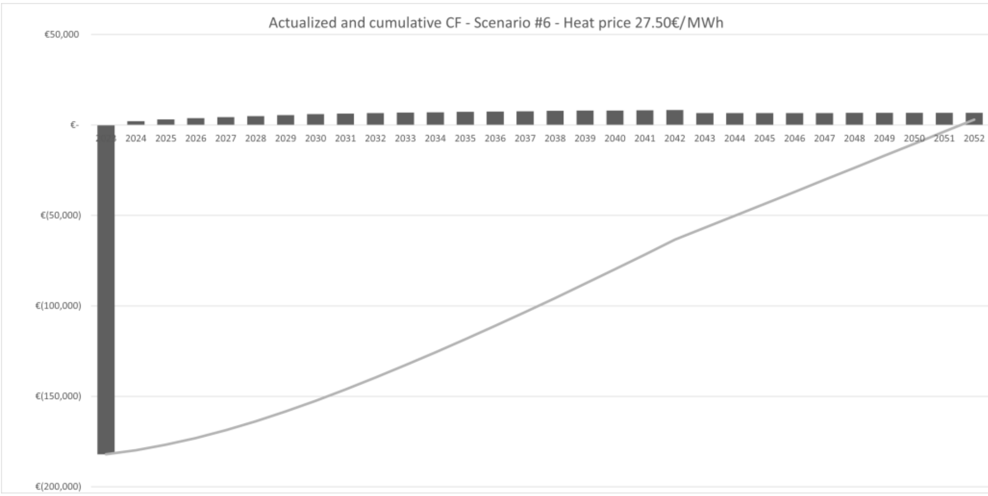


Figure 44. Actualized and cumulated cashflow for the utility under scenario 6.

With this configuration, however, the data center may no longer consider the investment profitable. According to this forecast, in fact, the NPV in the 30 periods considered of the investment would be negative. Furthermore, considering that a business company is usually interested in a return in the short term, 30 periods may already be unattractive.

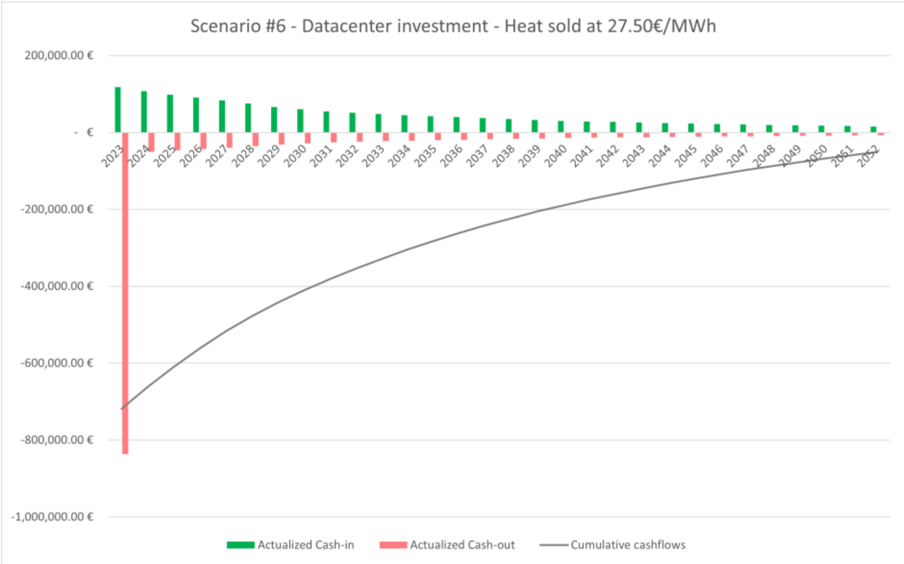


Figure 45. NPV and actualized and cumulated cashflows for the datacenter under scenario 6.

For the second time we see how the price limit imposed by law discourages investments in heat recovery technologies which would otherwise be benficial for the environment. For end customers, however, there is a tangible benefit: although the sales price is maximized at the price cap for the entire period, it is still lower than the current tariffs applied by AAFOR. Given the current price cap and its evolution linked to inflation (probably optimistic and quite unrealistic), however, there is no "equilibrium" heat sales price between the datacenter and the utility that makes the investment attractive for both actors in the game.

The only way forward would be to negotiate a higher price cap with the Danish Energy Agency. For example, assume a fixed price cap for the entire period 56% higher than that of 2023. This would translate into a heat sales price cap (no VAT) of 70 €/MWh. If the sales price to the district heating user is maximized at this price cap, it would still be lower than the AAFOR sales tariff of recent years.

With this condition, a higher heat purchase price can be negotiated between the utility and the datacenter, let us assume 40 €/MWh, close to the price decided in Scenario 5. At this point, the datacenter collects a larger share for the sale of the heat produced, and this makes the investment more attractive to all parties.

With the assumed values, the utility and datacenter cash flows can be estimated.

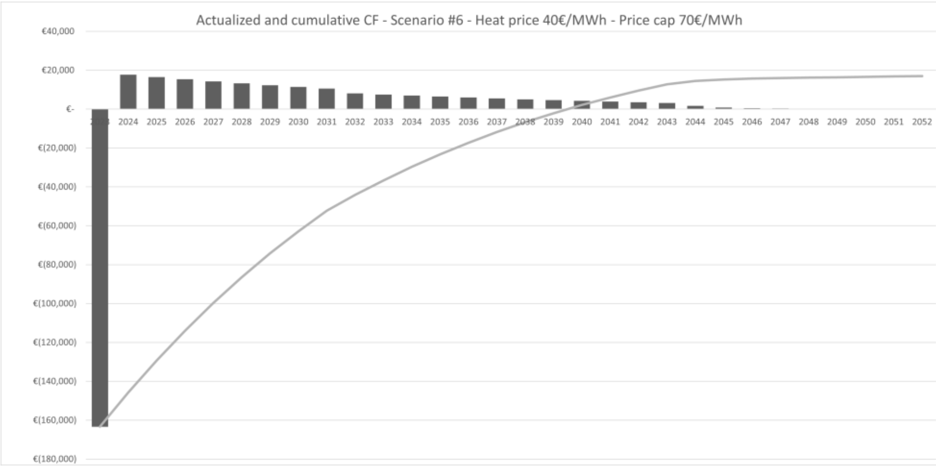


Figure 46. Actualized and cumulated cashflow for the utility under scenario 6 and increased price cap.

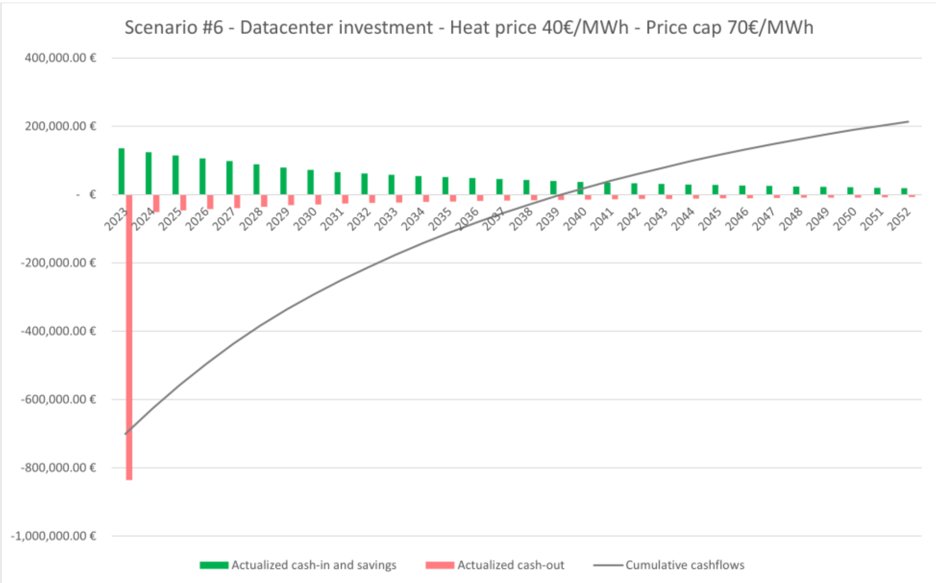


Figure 47. NPV and actualized and cumulated cashflows for the datacenter under scenario 6 and increased price cap.

After the BEP is reached, any profits made in the previous year are also taken into account when calculating the cost-based customer tariff. Should this tariff now fall below the price cap, the utility will charge this heat sales rate, resulting in benefits to end customers. In this case, this happens 5 periods after the BEP is reached, as a result of decreasing depreciation rates of the utility's assets.

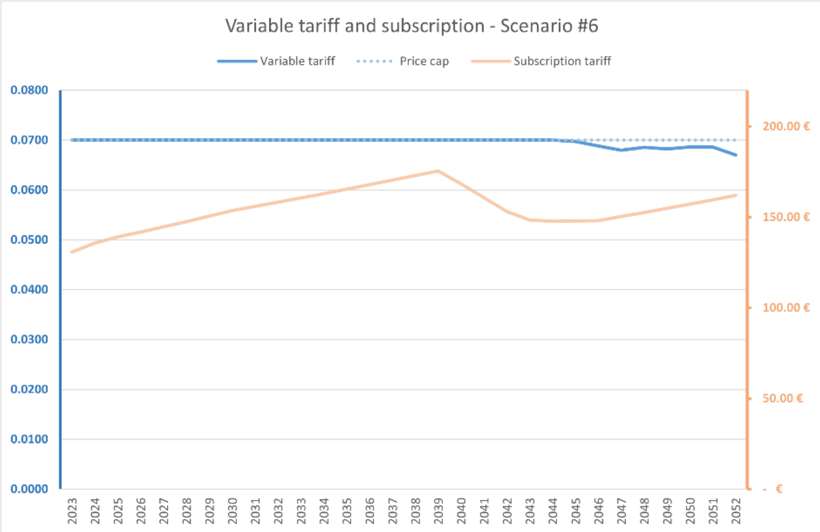


Figure 48. Tariff evolution for scenario 6 of the Danish case with increased price cap.

4.6.7 Comparison of proposed scenarios

Below is the comparative table of the analyzed scenarios. Feasibility refers to a return on investment for the utility company over the 30-year time frame. If this was not possible, additional assumptions were made to make it possible. The Solution column summarizes just the action taken. In the scenarios, the datacenter took an increasingly central role, up to scenarios 5 and 6 where the risk of the investment rests more heavily on it. This is why the interest of the university has also always been considered, as a crucial player in this heat recovery project.

The law makes multiple depreciation modes available. Therefore, wherever possible, Option 2 has been preferred, which allows higher portions of depreciation, as well as an increased valuation of the value of the assets. This provides a greater tax shield effect in the first years after investment and higher cash flows.

Finally, IRR was evaluated without the assumption of a nonprofit policy, while the assumptions regarding price cap and cost-based pricing mode were retained. This was done so as not to distort the value of the metric that would tend to WACC in any case because of this policy. While unrealistic, the calculated IRR expresses the potential and profitability of the investment.

	Feasibility	Solution	Payback period for utility	Depreciation	Recovery rate 10 years	IRR for utility
Scenario #1	■		17	Option 2	80%	5.72%
Scenario #2	■		22	Option 2	52%	4.78%
Scenario #3	■	Cost based pricing + 20€/MWh for 6 periods	30	Option 2	75%	4%
Scenario #4	■	Shift "cooling kit" costs to the university Payback period university: 19	18	Option 2	58%	5.58%
Scenario #5	■	Payback period university: 19	13	Option 1	56%	5.62%
Scenario #6	■	Feasible with higher price cap (+56%)	18	Option 1	73%	5.27%
■ = The scenario is feasible with the basic assumptions, **■ = Further assumptions are needed to make the scenario feasible**						

4.6.8 Implications on environment

All of the scenarios analyzed involve connecting new customers and replacing individual heating systems. We then hypothesize what the environmental savings might be with different heating technologies. The standard values used are those reported by the Danish Energy Agency.

Datacenter power connection	New customers	Delivered heat	Technology replaced	CO2 savings
80 kW	21	378 MWh/y	Natural gas boiler 95% efficiency	79.9 tonCO2/year
320 kW	85	1,537 MWh/y	Natural gas boiler 95% efficiency	323.4 tonCO2/year
80 kW	21	378 MWh/y	Oil boiler 90% efficiency	120.2 tonCO2/year
320 kW	85	1,537 MWh/y	Oil boiler 90% efficiency	486.3 tonCO2/year

5 Conclusions

This section aims to explore and highlight the main outcomes derived from the analysis of the three demonstration sites. The objective is to carefully examine the dynamics that emerged in the cases, identifying the determinants that can catalyze optimal exploitation of urban thermal resources. Through this analysis, we aim to outline in detail the key components of innovative business models capable of effectively incentivizing the transformation of waste heat into a valuable resource for district heating networks.

In particular, strategies suitable for both low-temperature thermal networks, which take advantage of lower-temperature heat sources, and high-temperature networks, which supplement the same sources with the help of heat pumps or warmer sources, are discussed.

In the cases analyzed, a district heating network already exists. These networks exploit large heat sources, such as geothermal heat available underground, or large waste-to-energy or cogeneration plants.

In LIFE4HeatRecovery, the integration of third, fourth or fifth generation networks with locally available waste heat sources is promoted to pursue one or both of the following objectives:

1. Replace current non-renewable sources with which heat is centrally generated, then distributed. In Europe, 2/3 of the heat distributed via district heating comes from non-renewable sources, such as natural gas, hard coal, and non-renewable waste. Integration of these sources is an alternative to replace a portion of heat with renewable sources. A viable alternative is to integrate these sources to better handle peak demand: waste heat acts as a constant baseline for heat demand when available, while other higher-emitting sources are used to handle peak situations.
2. Increase the current supply of available heat, thus connecting new users who can thus replace their individual heating systems, in most cases gas or oil boilers (which in any case appear to be less efficient than heat production with the same sources, but in a centralized manner).

In both cases, integrating new sources of waste heat can bring the utility company operating the service and network an *economic* benefit as well as an *environmental* benefit. With LIFE4HeatRecovery, it is intended to demonstrate first that pursuing actions that provide savings on overall pollutant emissions does not mean foregoing a future economic return that makes the initial investment acceptable. Second, it is intended to demonstrate that the viability of waste heat recovery can bring value not only to the utility company, but in a broader sense also to all those affected by this measure, with a focus on end users.

Waste heat is not necessarily related to the generation of energy from renewable sources. Even where the source originating the waste heat is considered 'sustainable,' such as electricity (e.g., database) or biomass, this does not automatically imply that the associated environmental impact is absent. The crucial aspect to understand is that low-temperature waste heat must be seen as an unavoidable by-product of a different production process. The European Union itself considers waste heat as a sustainable source and defines it in the following way: 'waste heat and cold' means unavoidable heat or cold generated as by-product in industrial or power generation installations, or in the tertiary sector, which would be dissipated unused in air or water without access to a district heating or cooling system.' Waste heat, excess heat, residual heat are all valid terms that refer to this definition.

In the case where the utility company decides to replace alternative heat sources with waste heat sources, in principle it could earn a higher profit margin by replacing the operating and fossil fuel cost with an operating cost for heat recovery close to zero, net of investment costs. In the case, on the other hand, of deciding to use waste heat to annex new customers to the grid, the higher profit would come from the sum of the margin that each customer provides through the payment of tariffs, again net of a not insignificant initial investment. However, one cannot reduce the analysis to operational cost alone; such a decision requires considering a range of relationships with different stakeholders, each of whom expects to derive an economic benefit from such an initiative. It is therefore critical to balance these expectations, even though this may result in a lower economic return for the utility company. Balanced management of these relationships is essential to ensure the long-term sustainability and acceptance of the project.

Moreover, unlike traditional thermal networks characterized by a limited number of large plants responsible for heat generation, the integration of district heating networks with waste heat sources requires a substantial conceptual revolution. In this new perspective, thermal energy distribution involves significantly more urban heat sources. Such an approach, although promising in terms of environmental sustainability, could involve more complex management and require larger initial investments, precisely because many more sources would need to be connected for the same amount of thermal energy. Expanding the grid to a plurality of waste heat sources implies a redefinition of management strategies, increasing the need for judicious planning and adequate financial resources to ensure its success.

5.1 Skid

To effectively pursue this new energy vision, LIFE4HeatRecovery has the ambitious goal of promoting the creation and standardization of *skids*, which are prefabricated modules containing all the plumbing and electronic systems necessary to physically draw heat and deliver it to the city grid. The skid would also include any water-to-water heat pumps needed to increase the temperature of the heat drawn from the source. This standardization aims to significantly simplify the installation process, allowing for quick and efficient connection. The adoption of standardized skids not only reduces the invasive impact to the urban heat supplier but also helps to contain the overall implementation costs.

Increased standardization and the resulting reduction in costs for prefabricated (skid) units are key elements in making investment in waste heat connection more attractive to investors. This is of crucial importance, as plumbing and electronic components are the predominant expense item in the early stages of investment.

Standardization not only simplifies the process of installing and connecting units, but also promotes economies of scale and replicability, allowing overall costs to be contained. By reducing plant complexity through component standardization, it paves the way for greater operational efficiency and easier adoption of district heating solutions based on waste heat sources. Moreover, standardization can enable reusability of the systems in different applications, providing a solution to mitigate the risk of having a waste heat source quitting the supply due to bankrupt or other market issues: a reusable skid would never become a stranded asset, as it could be reinstalled at another waste heat source.

In this context, it is crucial to emphasize that greater uniformity in hydraulic and electronic components not only lowers initial costs but also helps create a favorable environment for investors, making the economic return on investment in the long term clearer and more predictable. In addition, the availability of standard solutions offers the advantage of shortening the design and procurement time, considering that suitable solutions are already available in the market, as well as interfering less with the heat supplier's activities.

Skids offer the ability to enable the heat supplier to become a "prosumer" as well, allowing it to directly use its own excess heat to produce hot water to heat its own rooms and offices. A multidirectional version of the skids can take heat and give it to the grid, or give some or all of it to the supplier itself for its own heating; in case the supplier's demand for heat exceeds its own willingness to supply it, heat could also be taken from the grid to meet the heating need. This flexibility gives the heat prosumer an active role in the management and optimal use of urban thermal resources.

With this property, a standardized skid would not only make the investment economically viable, but due to its multidirectional nature, it would incentivize greater participation of heat suppliers. An analysis of the case studies shows that, in several countries, there is no legislation guaranteeing district heating network utilities the right to access waste heat without an obligation to make an economic contribution to the supplier. For example, in the Netherlands, the new law under discussion proposes a rule that allows utilities to take heat without necessarily having to make an economic contribution to suppliers. In other countries, such as Denmark and Italy, although it is a topic of discussion, there is no legislation to ensure that utilities have free access to waste heat; the possibility of access depends on the supplier's ability to negotiate and availability. Skid multi-directionality is therefore a strategic lever to engage heat suppliers, allowing them easy and cost-effective access to heat, replacing their own individual systems, but ensuring a cheap (or free) source of heat for the utility.

Enabling simple prosumer heat suppliers can pose a risk to the continued availability of thermal resources. However, this situation also offers a unique opportunity to convince suppliers to actively participate in the district heating network, becoming a valuable economic source of heat for end users. To effectively manage variability and ensure adequate response to peak demand in the grid, careful planning involving supplier diversification is essential, ensuring a stable and resilient supply of heat. Diversification of heat sources helps to mitigate the risks associated with suppliers' self-consumption of heat while at the same time exploiting the economic and environmental potential of this mode of energy supply. This is why the multi-directionality property of skids is considered critical.

In conclusion, declaring the importance of the standardization process is a critical first step in business model development. Immediately available solutions optimize the investment on the side of both investors and energy suppliers, making it cheaper, faster, more flexible to connect to urban waste heat sources.

5.2 Value proposition

The specific analysis of the three cases highlights how the integration of low-temperature urban waste heat sources brings differential benefits depending on the context and circumstances of the utility company. However, in general, some common value propositions can be identified compared to a network that does not exploit such sources.

Environmental Sustainability	The core value proposition focuses on *environmental sustainability through the replacement of higher-emission sources* in the district heating network or individual heating systems. The analysis shows that the replacement of individual systems, which are generally less efficient than centralized heat production, generates a greater benefit. The key metric for assessing the impact of this transition is the annual reduction in CO2 emissions. Although the waste heat recovery system involves marginal emissions, the analysis indicates that on average up to 84 kg of CO2 can be saved for every MWh of heat produced. This tangible demonstration of sustainability underscores the commitment to optimizing energy efficiency and contributing to the mitigation of greenhouse gas emissions.
Energy Efficiency	*Resource optimization*: by harnessing otherwise wasted heat sources, primary energy use is significantly reduced, contributing to a higher degree of overall energy efficiency. *Transformation to next-generation networks*: the transformation of old-generation networks to new-generation low-temperature networks is actively promoted. Under proper conditions, these networks can be more efficient, reducing heat losses during transport and promoting greater efficiency in heat end use. *Advanced peak demand management*: proper differentiation of heat sources along with the integration of thermal energy buffers enable more effective peak demand management. This optimization strategy helps maintain stable heat supply while reducing loads on the grid during peak periods.
Cost competitiveness	*Optimization of heat costs*: waste heat, being an excess by-product of other production processes, has a lower cost than heat production through other systems, such as cogeneration or heat generation. *Investment efficiency*: the need to make many more connections to recover waste heat, for the same amount of thermal energy, results in moderate-sized investments spread over time. This approach allows easier financial management for the utility company than a single large investment. *Reflections on tariffs*: This financial management model results in more consistent and lower tariffs for network end users, helping to ensure long-term cost competitiveness.

Incentive for local economic growth	The integration of waste heat sources not only *actively involves prosumers* in the energy system, with opportunities for savings on their own heating system, but also creates opportunities for *collaboration with manufacturing and electronics companies* to produce the necessary components. It also encourages the *participation of professionals and manufacturers* in the installation and implementation of the system, stimulating interaction between local actors and supporting economic growth at the local level.
Increased security of supply	The introduction of *diversified heat supply sources* helps to strengthen the security of heat supply. As highlighted in the analysis, in some scenarios, users experienced interruptions in service as a result of failures occurring in one of the main plants. Diversifying heat sources is therefore a key strategy to mitigate the risk of outages, ensuring more reliable continuity in heat supply to end users.
End-user security	Replacing individual fossil-fueled heating systems with a centralized supply system contributes significantly to improving the safety of end users. By reducing the use of fossil fuels in individual systems, the risks associated with potential malfunctions or accidents are minimized, providing a *safer and more reliable heating environment* for residential and commercial users.

5.3 Customer segments

In the analysis of the pilot cases, two main customer segments were distinguished: domestic and service, as well as the supplier acting as a prosumer and internal user of its heat, generally in office areas and corporate common spaces.

The household segment, a particular priority in all three cases, includes those still using individual fossil fuel heating systems for space heating and hot water preparation. In each of the three countries, it is planned to eliminate natural gas connection for households in the medium term. As an alternative, connection to district heating networks is considered one of the main approaches to replace the use of fossil fuels in heating. In general, in cases of domestic users, there is a tendency to favor areas with high population density to optimize supply efficiency and convenience of connection to the district heating system. Choosing areas with higher concentrations of housing facilitates the management of connections, reducing time and associated operating costs.

However, differences among countries have led to specific considerations for the effectiveness of the business model:

- The city of Aalborg and, more generally, Denmark already boast high district heating adoption rates, exceeding 80 percent. In this context, it is appropriate to conduct a careful evaluation on whether the waste heat source can be used to extend the grid or employed as a substitute in fossil-fueled central heat generation. For the Aalborg demo site, the option of connecting new utilities was considered, although it is recognized that it might be more effective to allocate the heat to heating the university buildings from which this heat is drawn.

- In the Dutch context, prioritizing the replacement of individual natural gas heating systems, which are still widely used, becomes more relevant. In the Netherlands and Denmark, where most of the building stock is owned by housing associations, the importance of focusing on this segment is highlighted. Although the focus on end-customer acceptance of the technology remains critical, it is crucial to emphasize that the utility must consider associations as the customer with whom to define the best connection solution. Compared to individual household customers, associations have more power in the contracting phase, as they represent dozens or hundreds of potential new customers at the same time. This approach significantly simplifies the preparatory process, allowing the utility to acquire many new customers through a single negotiation.
- In the Italian context, the priority is moving toward replacing individual natural gas heating systems, which are still widely used and predominantly privately owned. In this scenario, a strategic option could focus on large housing complexes and condominiums (though this is less widely applicable in little towns like Ospitaletto), ensuring not only greater district heating efficiency but also simplifying the agreement process between the utility and owners. The primary interest of the end customer lies in the promise of cheaper prices than gas boilers. Prioritizing the conversion of cases with central heating would be a win-win, accelerating the acquisition of new customers with low costs. Modifying and connecting the central heating system proves more effective than replacing numerous individual heating systems.

Waste heat recovered and distributed through district heating systems represents a valuable energy resource that can also be successfully allocated to utilities in the service sector, public buildings, or offices. In the context of Heerlen, the potential connection of a public swimming pool to the district heating network was examined. This case offers interesting insights into whether a commercial utility should be preferred over a domestic utility connection. In the case of such a large commercial utility, equivalent to about 100 households in terms of energy demand, the utility company guarantees a significant revenue stream with a single connection. This translates into faster customer acquisition processes and lower operating costs. Connecting domestic utilities, on the other hand, would involve more invasive and prolonged road work, as well as a more extensive acquisition process over time. A single customer also improves supply efficiency, with lower heat losses. In the Heerlen context, it was possible to evaluate a pricing system that would not have been achievable with residential customers. High heat connection, in fact, does not fall within the price limits imposed by the national regulator, allowing the negotiation of dynamic pricing systems between the parties involved. Even in the Italian landscape, where there are no precise caps on the rates charged, recent investigations into pricing systems have focused mainly on residential customers, seemingly giving utilities greater flexibility in setting terms of sale with commercial customers. In general, commercial customers are often concentrated in specific geographic areas, facilitating the creation of clusters of utilities that can be served by one or more heat sources within the cluster. This simplifies distribution and reduces the need to extend the district heating network to reach numerous residences.

In addition, commercial customers have the potential to act as prosumers, recovering heat from their own cooling systems, as in the case of supermarket refrigeration systems, data centers at these customers, or generally cooled environments. This heat can be reused directly by them or reintegrated into the district heating network.

End user	Middle customer	Role and interest
Domestic user: - Private house/apartment owner - Tenant	- Private house owner - Apartment building - Lessor (private housing) - Housing associations - Housing cooperatives	Room heating Hot water Supply guarantee Low prices (compared to pre-existing situation) System safety
- Commercial customer - Office building - Public building (schools, hospitals, municipal buildings, libraries...)	- Local authorities - Building owner	Room heating Hot water Supply guarantee Stable prices System safety Heat prosumer

5.4 Key partnerships and activities

During the case analysis, key partners emerged whose involvement is crucial to the applicability of the business model in the context of waste heat recovery and the effective operation of heat supply to the end customer. These partners, active players at different stages of the project, play a key role, requiring a close and collaborative relationship both in the preliminary stages and during implementation. This synergy with strategic partners is pivotal to the overall success of projects in the long term, helping to ensure efficient and sustainable management of urban thermal resources.

The following table, summarizes the identified stakeholders and their roles.

Stakeholders	Role/activities
Electrical supplier	Crucial to ensuring the energy supply needed for waste heat recovery and distribution processes. Urban heat recovery stimulates the shift to an all-electric district heating system. Crucial for supplying power to heat pumps (at the supplier level for high-temperature networks or at the customer-only level for low-temperature networks). Collaboration enables synergistic integration of energy flows, promoting overall system efficiency, stimulating conversion to renewable sources for electricity generation as well, and establishing tariffs for planning over the medium term.
Gas supplier	Needed to plan and implement the phased disconnection of gas systems, including the closure of related infrastructure. Collaboration is essential to manage the transition to more sustainable sources and ensure the safety and reliability of the process.
Network operators	Collaboration with managing entities of other networks, such as water utilities, to optimize integration and synergy between different systems. Joint management promotes a holistic approach to waste heat recovery and distribution, maximizing its effectiveness and sustainability.
National regulatory bodies	Fundamental to ensure compliance with national energy and environmental regulations. Cooperation with national regulators ensures compliance of the business model, facilitating the regulatory path and contributing to its acceptance at the governmental level. In the Danish case, it emerged of how the regulator is willing to discuss possible price cap exemptions. In general, the primary interests of these bodies are the protection of users and the promotion of sustainability measures, so it makes sense to collaborate with them from the earliest planning stages in order to build a collaborative and synergistic environment.
Local authorities	In the analysis of the cases, there was a tendency to give increasing decision-making autonomy and responsibility to local authorities regarding strategic energy decisions that affect their territory. Given this, collaboration with local regulators, such as municipalities and provinces, is essential for utility companies. These partners are key to gain support and approval at the local level, facilitating acceptance of the business model in specific contexts. Given that work to implement waste heat and expand the grid involves work on roads and energy infrastructure, municipalities must grant the use of public land for the work. Local authorities also have the decision-making power in some cases (based on national legislation) to force customer connections if

	they are considered strategic to support the conversion of the built environment. The increasing responsibility given to local regulators, especially in the contexts of small and medium-sized municipalities, poses a risk for utility companies. In smaller municipalities, they may lack the expertise to evaluate complex district heating and waste heat recovery projects, making the decision-making process more time-consuming and complicated. The need to coordinate the bureaucratic process efficiently therefore becomes crucial to ensure a smooth transition to more sustainable energy solutions.
Lenders of the initial investment	The participation of lenders and the extent to which they contribute to the initial investment of projects are closely linked to the medium- to long-term operational perspective of heat recovery and sale to users. Participation also depends on the corporate structure of the district heating company. Potential players who can contribute financially include: - Heat Producers/Prosumers: heat producers play an active role in long-term operations. From such involvement comes a tangible benefit, such as an economic reward for the heat transferred or a source of indoor heating and hot water production or the achievement of sustainability goals. Consequently, it is reasonable to expect these companies to participate financially to some extent in the investment in the heat recovery system. The area of investment could range from integration with their own heating systems, heat recovery systems, adaptation and construction of internal plumbing/energy infrastructure, to the cost for heat pumps (in case it is necessary to raise the temperature before feeding into the district heating network or into their local heating system). The level of financial contribution required will vary according to the agreements established between the parties, influenced by projections of the effectiveness and profitability of the investment over time. - The utility company, acting as the operator of the district heating network, plays a key role in financing waste heat recovery projects. This company derives direct economic benefit from the sale of recovered heat, making it a natural investor in such projects. To finance the investment, the Utility Company must enter into partnerships with lenders to pursue mainly two options: use of equity capital (equity) or debt acquisition.

	○ For a project with a long payback period, acquiring debt, such as through bank loans or bond issuance, may be a viable option because it spreads the cost of investment over time, making them appropriate for projects that generate gradual returns. Lending institutions and investment funds are increasingly interested in projects that support sustainability and energy efficiency, in part because they provide substantial security on future cash returns. In addition, in many European nations, such projects can benefit from concessional financing terms or government guarantees, making debt a particularly attractive option. ○ Although equity financing may be challenging for such a long-time horizon and tie up resources for an extended period, it should not be ruled out a priori. It could be considered if the Utility Company has sufficient internal financial resources, also considering that heat recovery systems will become increasingly economical. - Local authorities: the financial participation of local authorities in investments in heat recovery systems is influenced by capital structure and shareholding. Municipalities or provinces that own significant stakes in district heating utilities tend to directly support such investments. This type of support proves crucial, as it is through these investments that local authorities align with energy efficiency and emission reduction goals. In addition, investment in innovative solutions such as heat recovery fosters innovation and technological development, making communities more attractive for future investment. Collaboration between local authorities and utilities in the field of heat recovery can evolve into public-private partnerships or other forms of agreement, marking an important step toward creating more sustainable and environmentally conscious communities.
Suppliers, contractors, specialized installers	Suppliers of essential components such as piping, electronic hardware, plumbing pumps, heat pumps, and heat exchangers (configured in standardized skids), along with specialized contractors and installers, are a critical part of implementing energy efficiency and sustainability projects, such as those related to heat recovery. In an increasingly sustainability-oriented future, the demand for these specialized skills

	and skilled workers is likely to grow, making these resources critical and potentially scarce. In the face of this growing demand, it becomes strategic for energy efficiency companies to form key partnerships with these suppliers and professionals. These partnerships not only ensure access to essential technical resources, but also allow them to build a knowledge and skills base that can be leveraged to accelerate and optimize future projects.

5.5 Revenue and cost structure

The analysis on cost and revenue structure was deepened on the three projects implemented at the demo sites. For each case, a realistic scenario reflecting actual costs, agreements between the parties, technical choices, and heat use patterns, as well as the rates charged by district heating utilities in previous periods was taken as a reference. From each case, alternative scenarios were developed to assess the robustness of the project and the impact of different choices.

For each scenario, the size of the initial investment was assessed, due to the costs of skids, hydraulic components, electronics, and installation costs. From this, the operation of the system was projected over a medium-to-long time frame, in any case not exceeding 30 years, a period commonly adopted for asset depreciation or otherwise considered appropriate for assessing the return on investment.

As already pointed out, each proposed scenario has peculiar characteristics, distinct assumptions and different dimensions, making it impossible to establish a single universal criterion for assessing the feasibility of the investment. Nevertheless, it is possible to highlight a few determinants in the cost/revenue analysis that are crucial to the success and viability of the investment.

Utility companies derive their main revenue from paying customers for heat provided through district heating. New customers are particularly interested in lower heating and hot water costs than the heating technology they are replacing. At the same time, users already connected to the district heating network also expect prices to stabilize or decrease, in line with the decrease in the use of fossil fuels. The users' interest is thus twofold: sales tariffs must ensure a lower cost than the gas alternative in order to remain competitive, but they cannot be strictly tied to the gas price, especially where the grid exploits alternative sources. Business models that manage to keep tariffs lower please district heating users, ensure a longer-lasting relationship, and allow the utility greater flexibility in handling unforeseen expenses. Indeed, it would be more difficult for the public to digest further increases in already higher rates from other alternative technologies due to work on the grid.

As is evident from the scenarios analyzed, it is not easy to simultaneously secure low tariffs and a short payback period that can attract both utility companies and investors, as these two factors are in trade-off. As a result, utility companies move toward seeking additional alternative revenue sources that can offer more advantageous pricing terms and an appropriately short payback period. This approach aims to effectively balance the costs and benefits to ensure the sustainability and attractiveness of the project.

In the Danish situation, as illustrated in the first two scenarios, the utility company would be expected to bear the cost of the datacenter cooling process and the investment required for the connection. In return, it would receive an annual payment from the datacenter, which is a portion of the avoided cost for air cooling (CRAC). This arrangement allows the utility company to ensure that the payback is achieved over the time frame in question and to be able to offer the heat at a lower price than the maximum tariff imposed by the regulatory authority.

Another strategy is to share a portion of the investment cost with the heat supplier. However, this approach is advantageous for the supplier, given that it benefits from the heat for its own heating systems for free or at a very affordable rate. In the cases studied, it was always assumed that the supplier would bear the cost of retrofitting its own plumbing system, even going so far as to cover the cost of skid plumbing and technology components in some cases. In each situation, the supplier was guaranteed to recoup the investment through cost savings within a maximum period of 20 years.

The case of heat supplier participation in the investment was analyzed in the Danish case and did not prove to be as viable as the case of periodic payment for datacenter cooling service. In this case, it was reasonably asked to take care of the payment of all electronic components for controlling the cooling of the datacenter and preparing the site for skid installation. The amount of this work is about €80k, versus the €160k (NPV) that the utility would collect over the period for the cooling service. In this case, the alternative of payment for service appears to be a more viable route, as well as being less burdensome for the datacenter as it spreads this cost over several years.

Another significant option is government grants to finance activities. This type of financial support can play a crucial role in facilitating project implementation and ensuring its long-term economic sustainability. The main focus of government interest is on seeking greater energy efficiency, promoting increasing environmental sustainability, and stimulating the economy. These goals reflect a shared commitment to a more sustainable future.

Numerous government funds, subsidized financing programs, grants and other forms of financial support are available to promote investments in energy efficiency, environmental sustainability and economic stimulation. These resources are key to supporting projects that aim for a more sustainable and environmentally friendly future. In analyzing these scenarios, the main focus has been on the structural incentives that already exist in various countries. However, it is reasonable to anticipate that projects of this kind could also benefit from grant funding from local governments such as municipalities or other state or European programs, thus expanding the possibilities of support for sustainable initiatives and energy innovations.

In all scenarios where the business model does not prove profitable on its own, the government subsidy plays a crucial role, providing the economic support needed to make heat recovery projects feasible. In Italy, for example, the tax credit offered to utility companies represents additional revenue for each megawatt-hour (MWh) of heat delivered to the utility. This incentivizes utilities to maximize the amount of heat recovered, favoring this source over others in the grid.

The Dutch SDE++ incentive operates on a dynamic annual basis, calculated based on the actual operation of the grid each year. This mechanism makes it possible to cover the difference between the utility's gain per MWh delivered and a regulatory-defined cap. Available for the first 15 years, the goal for utilities is to accelerate the amortization of investment costs to maximize the benefits from this incentive.

The main cost items for the initial investment include:

1. **Hydraulic Components (skids)**: necessary for collection and delivery of the heat transfer fluid, ensuring multi-directionality of the skids.
2. **Electronic Components**: necessary for the measurement and operation of the hydraulic components. These components ensure that the system is not only efficient but also able to monitor and regulate the heat transfer process.
3. **Heat Pumps**: required to regulate the temperature of the collected heat according to the grid temperature.
4. **Heat Recovery Components**: crucial for the effective extraction of heat from production processes.
5. **Connection to the District Heating Network**: hydraulic components for delivering heat to the network.
6. **Pumps**: Used to move the heat transfer fluid within the system.
7. **Connecting Heat Recovery Systems to the Skid**: hydraulic and electronic components for transferring heat from the production site to the skid.
8. **Adaptation of the Supplier's Heating System (if Prosumer)**: critical to enable suppliers to become prosumers by integrating their heating system with the heat recovery project.
9. **Construction and Adaptation Costs**: the costs associated with the physical construction and space adaptation of existing systems.

Given the highly experimental nature of the LIFE4HeatRecovery project, it is important to recognize that the current costs cannot be seen as definitive for future projects. One of the primary goals of the project is to standardize the solutions used, which would lead to a reduction in costs over time. However, it is crucial to keep in mind that costs were estimated even before the recent crises, which caused a general increase in prices. This means that despite the potential decrease in costs through standardization, the current economic environment could still influence costs upward.

The initial investment for the three projects under the LIFE4HeatRecovery program ranged from 350,000 euros to 1.3 million euros. When considering the amount of heat that can be recovered annually, the initial investment cost for the project ranges between €780/MWh and €1080/MWh. This cost range reflects the investment required for heat recovery under different project scenarios, taking into account the technical specifications and capacities of each plant. The share for the installed hydraulic and electronic components represents a significant part of the total cost, which varied between 48 percent and 65 percent of the total investment.

Other relevant costs in the context of the LIFE4HeatRecovery project include those associated with connecting new customers. These costs cover a variety of expenses, such as road works, connections, replacement of pre-existing systems, installation of heat exchangers, metering systems, and additional plumbing and electronic components. It is important to note that this research excluded the calculation of these costs for domestic customers, assuming that the initial tariff paid by the user for connection was sufficient to cover all these expenses. However, this is a crucial component to consider, especially if the project is geared toward connecting a large number of residential customers rather than a few commercial customers, as the costs of expanding the network would have a greater impact in such a scenario.

Operating costs are another key aspect to consider. They include:

1. **Recovered Heat**: In some situations, it has been considered reasonable to recognize a fee to the supplier for recovered heat, despite the fact that it is technically a waste product. This approach, however, may be at odds with new legislative proposals, which seem to be moving toward the right of utility companies to recover heat without having to recognize a payment to the supplier. This difference in approaches reflects a still-evolving issue in the regulatory and market environment regarding waste heat recovery.
2. **Electricity**: Needed to power pumps, heat pumps, meters and other electrical components. This represents an ongoing cost for the efficient operation of the system.
3. **Administrative Costs**: Associated with managing relationships with new heat suppliers and customers. These costs involve everything related to the organization and bureaucracy of the project.
4. **Maintenance Costs**: These refer to maintenance on customers, suppliers and the network itself.

In the three cases analyzed by the project, it was considered that the fixed tariff paid by end customers would be adequate to cover the costs of routine maintenance and administration.

The in-depth analysis on the three projects implemented in the LIFE4HeatRecovery program demo sites provided an understanding of costs and revenues, considering realistic scenarios based on actual costs, agreements, technical choices, heat use, and pre-existing tariffs. Each scenario, with its peculiarities and dimensions, demonstrates that there is no universal criterion for assessing investment feasibility. However, some key factors emerge as determinants of investment success and affordability. Utility companies, for example, depend primarily on customer payments for heat supplied, with an increasing need to balance competitive rates and operational sustainability. Seeking additional sources of revenue, along with government financial support, becomes crucial to ensure the long-term sustainability and attractiveness of the project. This analysis emphasizes the importance of a balanced strategy that considers all financial, operational, and market aspects for the success of heat recovery projects.

5.6 Environmental implications

Waste heat recovery projects such as those analyzed in the LIFE4HeatRecovery program have significant environmental implications, especially in terms of reducing urban greenhouse gas emissions. The use of surplus heat makes it possible to expand the supply of heat by replacing individual domestic or commercial heating systems with connection to the district heating network. This contributes significantly to the reduction of greenhouse gas emissions, addressing one of the major contributors to urban pollution. To assess the environmental impact of waste heat recovery projects, the CO2 emission savings from replacing gas boilers with 95 percent efficiency-an average value for boilers in Europe-was estimated. To effectively compare data across countries, an indicator of CO2 saved each year for each euro of initial investment was calculated. This indicator considers a similar duration of intervention over time, thus enabling a comparative and uniform assessment of the environmental effectiveness of the initial investment in different national contexts.

	Delivered thermal energy	CO2 savings by replacing 95% efficient gas boiler	CO2 savings yearly / € of initial investments
Italian	777 MWh/y	165.48 tonCO2/year	169.72 gCO2/y/€inv.
Dutch	2251 MWh/y	506 tonCO2/year	474.41 gCO2/y/€inv.
Danish	378 MWh/y	79.9 tonCO2/year	223.81 gCO2/y/€inv.