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# SWEET Call 1-2020: SURE

# Deliverable report

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| **Deliverable n°** | D15.1 |
| **Deliverable name** | Techno-economic cost-effectiveness analysis of process heat decarbonization options |
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| | |
|---|---|
| AHP | Absorption Heat Pump |
| CCGT | Combine Cycle Gas Turbines |
| CHP | Combined Heat and Power |
| COP | Coefficient-of-performance |
| BG | Biogas |
| DL | Deliverable |
| DH | District Heat |
| EP2050+ | Energy Perspectives 2050+ |
| FLH | Full Load Hours |
| HP | Heat pump |
| HTHP | High Temperature Heat Pumps |
| GHG | Greenhouse gas |
| GHGE | Greenhouse gas emissions |
| IWB | Industrielle Werke Basel |
| MBtu | Mega British thermal unit |
| NG | Natural Gas |
| OPEC | Organization of the Petroleum Exporting Countries |
| OEM | Original equipment manufacturer |
| OM | Operation and Management Costs |
| PtH | Power-to-Heat |
| PtG | Power-to-Gas R&D Research and development |
| SHP | Separate heat and power |
| SFR | Swiss Federal Railway |
| SFOE | Swiss Federal Office of Energy |
| SPS | SURE Pathway Scenario |
| TDHP | Thermally Driven Heat Pumps |
| VHTHP | Very High Temperature Heat Pumps |
| W/W HTHP | Water/Water High Temperature Heat Pumps |

## Summary

This deliverable, D15.1, addresses the cost-effectiveness of process heat decarbonisation and power-to-heat options in the manufacturing industry with process temperatures of up to 120 °C. Options include high temperature heat pumps (HTHP), renewable or low-carbon fuels or combined heat and power plants. Previous studies have identified a large potential to adopt such options in Switzerland. However, high technology, energy and integration costs have been obstacles to integrate these technologies in existing processes. In addition, energy price developments have been very dynamic. Hence, we here provide an up-to-date assessment.

Based on literature, we first describe relevant options. Second, we identify the options which are most cost-effective for saving greenhouse gas (GHG) emissions using the abatement-costs method. For this, we rely on technical and cost parameters from sources such as the FORECAST model and literature. Energy prices stem from the area of Basel, and international natural gas price predictions are partly adapted from previous work in SURE. Finally, dynamic emission factors for the Swiss context are used.

Our results shows that HTHP are very cost-effective, particularly for small temperature differences between heat source and sink. GHG abatement costs for saving 1 kiloton of CO2-equivalent can be less than -200 CHF for a 1MW system, in other words, net savings can be expected. Furthermore, low-carbon fuels, district heating options may be competitive options depending on the energy price situation, whereas hydrogen options are still very expensive. A sensitivity analysis shows the relevance of energy price components and full load hours.

The deliverable is complemented by insights from original equipment manufacturers (OEM) of HTHP who see a rise of interest in their products, both in the industrial and public sector. Furthermore, the HTHP OEMs have contributed to the validation of our input parameters. Results from this deliverable set the foundation for an upcoming survey with the industry of Basel.



## Zusammenfassung

Deliverable D15.1 befasst sich mit der Kosteneffizienz von Optionen zur Dekarbonisierung von Prozesswärme und Power-to-Heat in der verarbeitenden Industrie, welche mit Prozesstemperaturen von bis zu 120 °C arbeitet. Zu den Optionen gehören Hochtemperaturwärmepumpen (HTHP), erneuerbare oder kohlenstoffarme Brennstoffe oder Kraft-Wärme-Kopplungsanlagen. Frühere Studien haben ein grosses Potenzial für die Einführung solcher Optionen in der Schweiz aufgezeigt. Die hohen Technologie-, Energie- und Integrationskosten waren jedoch ein Hindernis für die Integration dieser Technologien in bestehende Prozesse. Darüber hinaus war die Entwicklung der Energiepreise sehr dynamisch. Daher liefern wir hier eine aktuelle Analyse.

Auf Basis der Literatur beschreiben wir zunächst die relevanten Optionen. Zweitens ermitteln wir anhand der Vermeidungskosten-Methode jene Optionen, die am kosteneffizientesten bei der Einsparung von Treibhausgasemissionen sind. Dabei stützen wir uns auf technische und Kostenparameter aus Quellen wie dem FORECAST-Modell und der Literatur sowie auf Energiepreise aus dem Raum Basel, eine aus SURE D2.1 adaptierte Preisentwicklung und dynamische Emissionsfaktoren für den Schweizer Kontext.

Unsere Ergebnisse zeigen, dass HTHP sehr kosteneffizient sind, insbesondere bei kleinen Temperaturunterschieden zwischen Abwärme und nutzbarer Wärmequelle. Die THG-Vermeidungskosten für die Einsparung von einer kilotonne CO2-Äquivalent können für ein 1-MW-System mehr als 200 CHF betragen, d.h. es können Kosten eingespart werden. Darüber hinaus können kohlenstoffarme Brennstoffe und Fernwärmeoptionen je nach Energiepreissituation wettbewerbsfähige Optionen sein, während Wasserstoffoptionen noch sehr teuer sind. Eine Sensitivitätsanalyse zeigt die Bedeutung von Energiepreiskomponenten und Volllaststunden.

Die Ergebnisse wurden durch Interviews mit Herstellern ergänzt, die ein steigendes Interesse an ihren Produkten sowohl im industriellen als auch im öffentlichen Sektor feststellen. Darüber hinaus haben die Hersteller zur Validierung unserer Eingangsparameter beigetragen. Die Ergebnisse dieser Studie bilden die Grundlage für die kommende Umfrage mit der Basler Industrie.

## Résumé

Ce livrable, D15.1, traite de la rentabilité des options de décarbonisation de la chaleur industrielle et de la production de chaleur dans l'industrie manufacturière avec des températures de processus allant jusqu'à 120 °C. Les options comprennent les pompes à chaleur haute température (HTHP), les combustibles renouvelables ou à faible teneur en carbone ou les centrales de cogénération. Des études antérieures ont identifié un important potentiel d'adoption de ces options en Suisse. Cependant, les coûts élevés de la technologie, de l'énergie et de l'intégration ont constitué des obstacles à l'intégration de ces technologies dans les processus existants. En outre, l'évolution des prix de l'énergie a été très dynamique. C'est pourquoi nous fournissons ici une évaluation actualisée.

Sur la base de la littérature, nous décrivons d'abord les options pertinentes. Ensuite, nous identifions les options les plus rentables pour réduire les émissions de gaz à effet de serre (GES) en utilisant la méthode de l'abattement des coûts. Pour ce faire, nous nous appuyons sur des paramètres techniques et de coûts provenant de sources telles que le modèle FORECAST et la littérature. Les prix de l'énergie proviennent de la région de Bâle, et les prévisions des prix internationaux du gaz naturel sont en partie adaptées de travaux antérieurs de SURE. Enfin, des facteurs d'émission dynamiques pour le contexte suisse sont utilisés.

Nos résultats montrent que les HTHP sont très rentables, en particulier pour de petites différences de température entre la source et le puits de chaleur. Les coûts de réduction des GES pour économiser 1 kilotonne d'équivalent CO2 peuvent être inférieurs à -200 CHF pour un système de 1MW, en d'autres termes, des économies nettes peuvent être attendues. En outre, les combustibles à faible teneur en carbone, les options de chauffage urbain peuvent être des options compétitives en fonction de la situation des prix de l'énergie, alors que les options d'hydrogène sont encore très coûteuses. Une analyse de sensibilité montre la pertinence des composantes du prix de l'énergie et des heures de pleine charge.

Le document est complété par des informations fournies par les fabricants d'équipements originaux (OEM) de systèmes de chauffage à haute pression qui constatent un intérêt croissant pour leurs produits, tant dans le secteur industriel que public. En outre, les OEM HTHP ont contribué à la validation de nos paramètres d'entrée. Les résultats de ce livrable jettent les bases d'une prochaine enquête avec l'industrie de Bâle.

## Riassunto

Questo deliverable, D15.1, affronta il tema del rapporto costo-efficacia delle opzioni di decarbonizzazione del calore di processo e del pow-er-to-heat nell'industria manifatturiera con temperature di processo fino a 120°C. Le opzioni includono pompe di calore ad alta temperatura (HTHP), combustibili rinnovabili o a basso contenuto di carbonio o impianti di cogenerazione. Studi precedenti hanno individuato un ampio potenziale di adozione di tali opzioni in Svizzera. Tuttavia, gli elevati costi tecnologici, energetici e di integrazione hanno ostacolato l'integrazione di queste tecnologie nei processi esistenti. Inoltre, l'andamento dei prezzi dell'energia è stato molto dinamico. Per questo motivo, forniamo qui una valutazione aggiornata.

Sulla base della letteratura, descriviamo innanzitutto le opzioni rilevanti. In secondo luogo, identifichiamo le opzioni più efficaci dal punto di vista dei costi per la riduzione delle emissioni di gas serra (GHG) utilizzando il metodo dei costi di abbattimento. A tal fine, ci basiamo su parametri tecnici e di costo provenienti da fonti quali il modello FORECAST e la letteratura. I prezzi dell'energia provengono dall'area di Basilea e le previsioni dei prezzi internazionali del gas naturale sono in parte adattate dal

precedente lavoro di SURE. Infine, vengono utilizzati fattori di emissione dinamici per il contesto svizzero.

I nostri risultati mostrano che gli HTHP sono molto convenienti, in particolare per piccole differenze di temperatura tra la fonte di calore e il dissipatore. I costi di abbattimento dei gas serra per il risparmio di 1 chilotone di CO2 equivalente possono essere inferiori a -200 CHF per un sistema da 1 MW, in altre parole, si può prevedere un risparmio netto. Inoltre, i combustibili a basso contenuto di carbonio e le opzioni di teleriscaldamento possono essere opzioni competitive a seconda della situazione dei prezzi dell'energia, mentre le opzioni di idrogeno sono ancora molto costose. Un'analisi di sensibilità mostra la rilevanza delle componenti del prezzo dell'energia e delle ore di pieno carico.

Il documento è completato dalle informazioni fornite dai produttori di apparecchiature originali (OEM) di HTHP che vedono un aumento dell'interesse per i loro prodotti, sia nel settore industriale che in quello pubblico. Inoltre, gli OEM di HTHP hanno contribuito alla convalida dei nostri parametri di input. I risultati di questo documento gettano le basi per una prossima indagine con l'industria di Basilea.

# 1 Introduction

WP 15 is structured into two topical case studies targeting the industrial (Tasks 15.1 to 15.3) and transport (Task 15.4) sectors. This document is the contribution of deliverable D15.1, a techno-economic cost-effectiveness analysis of process heat decarbonization options, complemented with stakeholder inputs from manufacturers of HTHPs.

## 1.1 Relevance

Generally, adopting PtH and low-carbon fuels in the industrial sector contributes to the integration of renewables in the power system (Bloess, Schill, & Zerrahn, 2018). In Switzerland, the industrial sector contributes 24.8% of all greenhouse gas emissions (GHGE) and is the second largest contributor overall (BAFU, 2022). Process heat in Switzerland, with a share of around 12%, is the third largest contributor to total final energy consumption. Moreover, process heat contributes to more than 50% of the total energy demand in the Swiss industries (BFE, 2022a). Of this heat, a large share is heat above 80 °C, as illustrated in Figure 1. Despite its significance, only a small share of industrial heat demand is met by decarbonisation options such as high temperature heat pumps or low-carbon fuels.

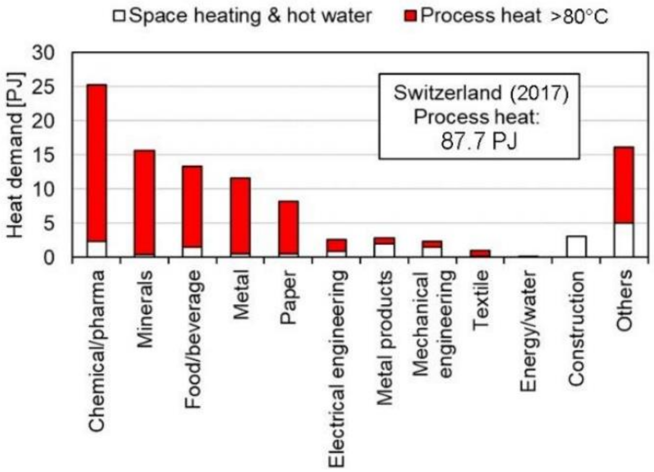


Figure 1: Heat demand in Swiss industry. The amount of energy consumption of process heat in 2017 was 87.7 PJ or 24.4 GWh. Sources of figure from literature (Arpagaus & Bertsch, 2020; BFE, 2022a).

In this deliverable, D15.1, we analyse costs of such process heat decarbonisation options, we show potential greenhouse gas (GHG) savings following a technology substitution, and finally, we compare the costs of the emission savings using a cost-effectiveness analysis. In addition, interviews with selected manufacturers and original equipment manufacturers (OEM) of industrial heat pumps (HP) puts the work into a current market context. This deliverable also lays the foundation for the D15.2, which analyses the attractiveness of such options for industrial customers and identifies the incentives needed to motivate utilities to offer specific products, such as preferred energy tariffs and energy (performance) contracting services.

Special attention is being attributed to the technology of high temperature heat pumps (HTHP) at industrial scale. This technology, which can supply temperatures above 80 °C, is becoming pivotal in the decarbonisation process with its unparalleled energy efficiency. To date, it is still considered a niche product for industrial purposes but has a very large dissemination potential in the low- to mid-heat temperature range in several industries in Europe (Figure 2). Although the industrial sector structure in Europe differs from the Swiss one, the illustrated chemical, food and paper industries are also of high relevance in Switzerland (compare Figure 1), warranting further research.

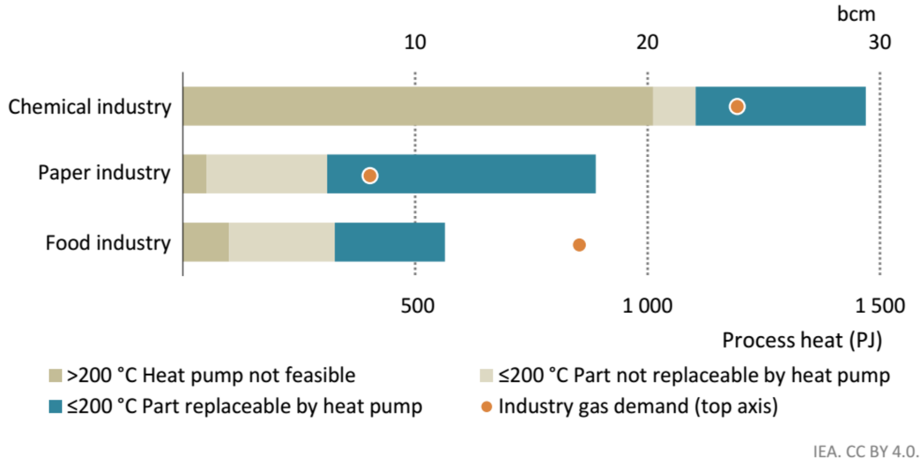


Figure 2: The dissemination potential of HTHP in Europe and different industries. The potential is dependent on the industry, it's typically useable temperature, and the availability of waste heat (IEA, 2022a).

The technology, even though widely spread for decades in small scale lower temperature applications and in selected countries as part of the district heating grid (DH), still offers technological development potential. Notably, there is potential to access applications with higher temperature heat sinks in the industrial sector. Even more so, as (very[1]) HTHP are accessing continuously higher temperature levels (Figure 3).

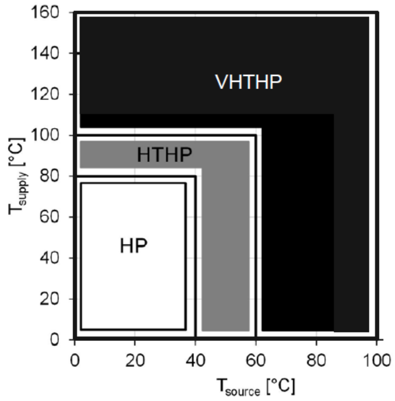


Figure 3: Potential of HP to transform the source temperatures into sink temperatures. Adopted from (Arpagaus, Bless, Schiffmann, & Bertsch, 2017) and based on (Bobelin et al., 2012; Chamoun, Rulliere, Haberschill, & Peureux, 2014; IEA, 2014; Jakobs & Stadtländer, 2020; Peureux, Haberschill, Rulliere, & Chamoun, 2012).

The current trend towards higher gas and carbon prices in Europe, as well as the ongoing decarbonisation of the electricity generation, increase both the competitiveness and GHG mitigation potentials of industrial heat pumps, rendering them a cornerstone technology in the future. In addition to HPs, low carbon fuels, the power to heat process and combined heat and power options are also covered in this deliverable.

This deliverable is structured as follows: The literature review in Section 2 summarises the current and relevant knowledge about PtH and low-carbon fuels. In section 3, the methodological approach and the assumptions and data for the economic analysis are declared. In section 4, the results of the economic cost-effectiveness analysis for the investment year 2020 are presented, and in section 5, the insights from the OEM interviews. The final section 6 discusses the results and provides a further outlook.

[1] We do not differentiate between HTHP and very HTHP (VHTHP) in the remainder of the deliverable.

## 1.2 General Objectives of WP15

WP 15 aims to apply the objectives, concepts, and approaches of SURE to specific issues of industrial demand and public transport, which are two sectors where the implementation of sustainability goals showed to be a particular challenge. In the first case, the cost-effectiveness and the potentials to replace fossil heat production with smart and competitive low-carbon electricity-based technologies such as power-to-heat (PtH) or with renewable gas such as biogas and other power-to-gas (PtG) fuels are explored. Empirical evidence about required payback periods, technical and operational pre-conditions, barriers and acceptance of industrial consumers are gathered. This includes the analysis of legal and regulatory aspects and the development of potential policy instruments to foster the adoption of decarbonization approaches in the industry sector. The second case investigates the interdependencies of the Swiss Federal Railway (SFR) in the Swiss energy system for several scenarios, with a particular focus on resilience and sustainability. SFR projections of future developments of electricity demand are integrated through the transmission grid model with the national energy system case study.

# 2 Literature

## 2.1 Overview of heat decarbonisation options

To decarbonise industrial heat provision, various options with varying challenges and needs for further Research and development (R&D) have been proposed (Thiel & Stark, 2021). The main options discussed in this deliverable are the electrification of heat provision, called power-to-heat (PtH), as well as the substitution of high-carbon fuels such as natural gas (NG) with low-carbon fuels such as biogas. Furthermore, Thiel & Stark mention other zero-carbon options that we do not focus on, such as heat from solar, nuclear and geothermal sources as well as optimized heat management.

PtH technologies include industrial size heat pumps, the direct conversion of renewable power to heat using electrical heaters, as well as the indirect utilisation of power via fuels like hydrogen (covered in the next section about low-carbon fuel). These technologies can be economically viable options provided that electricity prices are low and fossil fuel prices high, efficiencies are high, and the electricity grid is able to handle the increased load (Thiel & Stark, 2021). A decarbonised power mix is a precondition to achieve climate goals with PtH technologies. Continuous cost degression in the renewable energy production is accelerating the trend toward PtH technologies and is being observed (OECD / IEA, 2022).

### 2.1.1 High temperature heat pumps

Commercially available **high temperature heat pumps** (HTHP) currently deliver temperatures of around 100°C for steam generation. The type of the HP depends on the heat source and sink, notably ranging from water-water, brine-water, to air-water HPs. Water-water HP with capacities above 1MW per unit are typically mentioned in literature (Arpagaus, 2019; Thiel & Stark, 2021). However, higher usable temperatures of above 140 °C have already been achieved with laboratory prototypes (IEA, 2022a).

There is a surge in interest for the HTHP technology as demonstrated by an expanding product list (Arpagaus, 2019). Currently, there are already more than 34 HTHP products with supply temperatures above 100°C on the market, with several demonstration cases in the pipeline, as documented in the IEA's ongoing ANNEX 58 on heat pump-based process heat supply (Zühlsdorf, 2023). According to a Swiss OEM, HTHP have mainly been used in the operation of district heating, but more and more industrial partners show interest in HTHPs.

Alongside a growing product portfolio, efficiencies of new heat pumps are increasing, and new cooling fluids are developed (Arpagaus, 2019). While various (but not all) challenges to improve the efficiency of gas boilers have already been tackled (Tsoumalis, Bampos, Chatzis, & Biskas, 2022), HTHPs may still have a significant future improvement potential. Their efficiency, here represented by the coefficients of performance (COP), is dependent on the temperature difference ($\Delta T$) between the heat source and sink. Current commercially available products have COPs of up to 6 at low $\Delta T$ of 30 °C, however, R&D

projects (at $\Delta T=30°C$) have already exceeded COPs of 7 (Arpagaus, 2019). Furthermore, R&D in the areas of artificial intelligence (Johnson Controls, 2018), fluids (Johnson Controls, 2015) and heat carriage could significantly improve the cost-effectiveness of HTPH. Finally, with a stronger adoption of heat decarbonisation options, significant economies of scale may be unlocked. Among others, this includes costs for electrolysis, fuel cells, transport, and distribution infrastructure.

### 2.1.2 Low-carbon fuels

Low- or zero-carbon fuels include hydrogen, biofuels, and synthetic fuels. Their potential lies in the direct substitution of fossil fuels for processes which generate heat in boilers (Thiel & Stark, 2021). However, these fuels have heterogenous properties, and the literature mentions persisting challenges related to the integration, production, and economic viability.

Heat decarbonisation through **hydrogen** is gaining momentum due to the political will to promote hydrogen while financing hydrogen research and demonstration projects at large scale. A good example for this enhanced drive is the REPowerEU program that promotes the production of European hydrogen (European Commission, 2022).

Hydrogen is not only a chemical compound used in several industrial processes, but also a means to convert “excess”[2] power into heat (as PtH), to store it or to directly use it as fuel in the existing fossil-fuel based infrastructure (Thiel & Stark, 2021). Moreover, hydrogen may be suitable for high temperature processes above 200 °C (see also Figure 2), which is an advantage compared to other PtH options (EnergyNest, 2022; IEA, 2022b; Olsson & Schipfer, 2021).

Nevertheless, many challenges remain. Hydrogen needs to be produced in a more cost-effective but less carbon-intensive manner, losses in production need to be reduced, and properties in combustion processes need to be better understood to qualify as a feasible fuel replacement in the industrial sector (IEA, 2022a; Thiel & Stark, 2021). Currently, an emergence of large-scale hydrogen production facilities in middle eastern OPEC countries are ongoing. Also in Switzerland, pilot projects exist (Alpiq, 2022; SAK, 2022). Finally, Thiel & Stark further mention that a separate distribution network may be necessary. Research of converting existing natural gas pipelines for hydrogen transport is ongoing[3]. Overall, with a stronger adoption of such options, economies of scale may be unlocked to reduce costs for electrolysis, fuel cells, transport, and distribution infrastructure.

Heat decarbonisation through substitution of natural gas by **biofuels, bio-methane, syngas** or (electricity-based) **synthetic hydrocarbons** has further potential (Thiel & Stark, 2021). In contrast to hydrogen, such fuels serve as a one-to-one substitute avoiding many of the challenges associated with hydrogen. They can meet most of the industrial heat demand (Olsson & Schipfer, 2021). It is estimated that fully replacing or mixing conventional fuels with biomass reduces the GHGE of the European industrial sector by around 30% (Rehfeldt, Worrell, Eichhammer, & Fleiter, 2020).

Limitations are the availability of biomass, for instance, in Switzerland[4] and the higher prices in comparison to other options (see also our price assumptions in Section 3.2.2). Furthermore, costs for these alternatives are still high. The prices for syngas, which is based on hydrogen, or synthetic hydrocarbons, which is based on biomass or atmospheric $CO_2$, are naturally more expensive than their predecessors (Thiel & Stark, 2021). Furthermore, Thiel & Stark stress that the upstream GHG-emissions during the production of biofuels and hydrocarbons are essential to provide a climate compatible option.

[2] In order to be economically viable, hydrogen production needs to be predictable, hence, the concept of excess production may be a delusive one.
[3] As part of the research project H2HoWi in Germany: https://3r-rohre.de/industrie-wirtschaft/17-11-2020-erdgasleitung-wird-zu-100-auf-wasserstoff-umgestellt/
[4] https://www.wsl.ch/en/projects/biomass-potentials-switzerland.html

#### 2.1.3 Combined heat and power options

Combined heat and power options include any plants co-producing power and electricity. **Fuel cells** use a chemical process to generate electricity and can be configured as a combined heat and power plant (U.S. DOE, 2016). **Combined cycle gas turbines** (CCGT) are a combination of gas and steam turbines. Their potential to decarbonise the heat production depends not only on the specific plant type and their efficiency but also on the specific fuel (see low-carbon fuels above).

#### 2.1.4 Other PtH technologies

**High temperature electric boilers** may be an alternative to HPs if higher temperatures than achievable with HTHP are required. Notably, for temperatures above 200 °C, direct electrification is currently the preferred option, due to the lack of viable HTHP (IEA, 2022a). In order to be an economic option, special attention needs to be directed at lowering capital costs of direct electrification and receiving low electricity prices, as the efficiency of such heaters is limited to 1 (Thiel & Stark, 2021).

**Thermally driven heat pumps (TDHP),** like absorption and adsorption heat pumps (AHP) are another option to supply decarbonised heat or hot water with the use of less natural gas or with biogas. The technology is able to deliver high temperatures of up to 180°C and efficiently use natural and biogas. Also, its use does not strain the electrical grid. However, TDHP are only a marginal competitor on the market, and the current political attention is more directed towards electric HP. Hence, the adoption of TDHP may not be a priority in industry (EHI, 2022).

**District heating** networks can deliver temperatures of up to 125 °C and may therefore be used both as direct heat sources in industry and as a source of heat for higher temperature processes (BMVBS, 2012).

### 2.2 Integration in existing processes

While a one-to-one substitution of fossil fuels by low-carbon fuels poses comparably little integration challenges, the replacement of gas boilers by HTHP needs to be carefully planned. An optimised integration of the HTHP into existing processes ideally includes cooling applications and is essential to increase efficiency, reduce costs and ensure long-term competitiveness. For HTHP, procedures such as the PINCH-analysis are common in industry, and the coupling of cooling and heating processes maximises the overall energy efficiency (Arpagaus, 2019; Fleckl, Wilk, Lauermann, Beck, & Hofmann, 2018).

Tapping into the full potential of HTHP, AHP and district heating systems depends on low-exergy heat from other processes. If the company does not have access to sources such as local waste heat, remote heat sources may be an option, e.g., via the district heating. The respective grids are available in many cities in Switzerland, for instance in the canton Basel. The Industrielle Werke Basel (IWB) currently expand their district heating grid strongly[5]. Although their current grid only partially reaches industrial areas in Basel, the main campuses of the two largest pharmaceutical companies Novartis and Roche are in reach, thus rendering district heating a viable decarbonization option.

## 3 Methodology

The aim of the economic analysis is to explore the cost-effectiveness of decarbonising industrial heat provision using PtH and low-carbon fuels. For this, we provide a GHG-abatement cost analysis to illustrate the costs of saving GHGE if natural gas boilers are substituted (see Equation 3). We consider different processes required for hot water or steam.

[5] https://www.medien.bs.ch/nm/2023-bauarbeiten-im-2023-fuer-mehr-klimaschutz-und-eine-zuverlaessige-infrastruktur-bd.html

To assess the necessary economic requirements of PtH, we base our analysis on:

(i) techno-economic indicators of heat decarbonisation options that are surveyed from technology suppliers and assumptions from the FORECAST model project[6],

(ii) electricity price developments based on existing literature and assumptions, as well as reference prices from the area of Basel. This includes a carbon tax which is considered as an exogenous parameter in the energy price, and

(iii) life-cycle-assessment-based emission factors for the national electricity mix and the various energy carriers.

We present the investigated options and technical parameters in Section 3.1, and cost, price and GHG assumptions and calculation methods in Section 3.2. CHP options are explored in Section 3.3. The survey in Section 3.4 sets these assumptions into context.

## 3.1 Technical options and parameters

### 3.1.1 Comparison of decarbonisation options

Based on the identified options in the literature review, we analyse the options shown in Table 1. While a substitution could be made at the end of the lifetime of a boiler or when an economic revaluation suggests a replacement, we only compare total cost of ownership (see Section 6.1). In the techno-economic analysis, combined heat and power (CHP) is considered separately, as it also delivers electricity (for CHP-methodology, see Section 3.3).

It needs to be considered, that the potential to integrate certain options depends on the infrastructure such as the gas and DH grid. Particularly a district heat grid may not be available in remote industrial areas, and therefore, only be an option for some companies. Nevertheless, our deliverable provides a decision basis to explore the further expansion of such grids, namely whether the use of district heating stations as a NG-based boiler replacement is economically viable.

Table 1: Options of heat decarbonization. Technologies analyzed and corresponding energy carriers.

| Technology | Potential energy carriers |
|---|---|
| **Separate heat and power (SHP)** | |
| **District heating station** | District heat |
| **Electric boiler** | Electricity |
| **Gas boiler** | Natural gas / Biogas / Hydrogen |
| **HTHP** | Electricity |
| **Thermally driven HTHP** | Natural gas / Biogas |
| **Combined heat and power (CHP)** | |
| **Fuel cell (CHP)** | Hydrogen |
| **Combined cycle gas turbine (CCGT-CHP)** | Natural gas / Biogas |

### 3.1.2 Heat demand, full load hours and efficiencies

While we report investment costs for heat loads between 0 and 10 MW, our focus lies on a heat load of 1 MW. We have chosen this reference value with the current availability of industrial HP in mind. While some products are available above 1MW, the typical load of most HTHPs lies between 100 and 1´000 kW (Arpagaus, 2019; Thiel & Stark, 2021; Zühlsdorf, 2023). During our interview with the Swiss OEM the spokesperson reported that their machines produced between 0.5 and 15 MW. Higher loads may often be possible if multiple units are connected.

[6] See www.forecast-model.eu.

All options are assumed to be operated in base- to mid-load with either 3´000 or 6´000 annual full load hours (FLH). This parameter variation is used to show the effect of operation on yearly costs. The lower value, 3´000h, represents a two-shift operation from 8:00 to 20:00 on working days, and the higher value, 6´000h, represents a multi-shift operation with breaks only for maintenance. With a 1 MW system, representing a considerable industrial production, these assumptions result in a heat demand of 3´000 and 6´000 MWh, respectively. The Swiss OEM confirmed that these values are reasonable.

The final energy demand of SHP is calculated using the efficiencies or COPs of the heating units shown in Table 2. Efficiencies of electrically driven HTHP are investigated for different temperature differences (see 3.1.3). While thermally driven HTHP have a similar dependence on the temperature difference, we do not further investigate this effect but consider one single efficiency (the focus of our study lies on electric HTHP). Three investment years are provided for information purposes, but the main cost-effectiveness analysis focuses on the year 2020.

Table 2: Thermal efficiencies in three investment years for a heat load of 1 MW. COPs of HTHP see next section.

| Technology | 2020 | 2030 | 2040 |
|---|---|---|---|
| **Separate heat and power (SHP)** | | | |
| **Electric boiler** | 0.97 | 0.97 | 0.97 |
| **Thermally driven HTHP** | 1.80 | 2.00 | 2.20 |
| **Gas boiler** | 0.90 | 0.90 | 0.90 |
| **District heat station** | 0.95 | 0.95 | 0.95 |

### 3.1.3 Processes, COPs of HTHP and heat source

According to (Arpagaus & Bertsch, 2020) and (Obrist, Kannan, McKenna, Schmidt, & Kober, 2023), industrial applications of heat pumps using (waste) heat recovery include:

- hot air generation for drying processes,
- process steam generation for food and beverages (e.g., pasteurization),
- pulp and paper manufacturing,
- hot water generation for washing and cleaning processes (e.g., food and meat)
- flue gas condensation in biomass/waste incineration plants or
- production of plastics.

These processes differ regarding the heat source and sink, i.e., the source and temperature of the (waste) heat input and the required temperature for the process. We conduct the economic cost-effectiveness calculations for HTHP for typical industry processes (Table 3). To reach these temperatures, the systems operate at different (here unspecified) pressure levels. We also assume that the waste heat source comes at no additional cost (see Section 6.1).

Table 3: Overview of relevant processes and the effect on heat pump COPs (source: Arpagaus, 2019).

| Heat source / waste heat | Temperature of waste heat (°C) | Industry process / heat sink | Temperature of process (°C) | DeltaT (K) | COP |
|---|---|---|---|---|---|
| **Cooling water of CHP engine** | 80 | Steam generation | 100 – 110 | 20 | 7.0 |
| **Heat from cooking processes** | 90 | Drying | 120 | 30 | 5.2 |
| **Cooling** | 40 – 50 | Steam generation | 100 | 50 | 3.5 |
| **Cooling** | 40 - 50 | Drying | 120 | 70 | 2.7 |
| **Cooling** | 40 - 50 | Hot water | 80 | 30 | 5.2 |

Based on the list of processes, we also define different COPs for the (electric) HTHPs. The maximal efficiency of a heat pump, here the COP, is dependent on the temperature difference $\Delta T_{Hub}$ between heat source and sink. The following empirically-derived function describes this relation for commercially available units in 2019 and for an efficiency factor of 45% (Arpagaus, 2019):

$$COP_{HTHP_{el}} = 68.455K \cdot \Delta T_{\text{Hub}}^{-0.76}$$

Equation 1

In this deliverable, we only consider temperatures of up to 120°C, representing mature HTHP, as well as the temperature levels of DH stations.

### 3.2 Cost, price and GHG parameters for the cost-effectiveness analysis

#### 3.2.1 Technology specific costs and heat demand

Techno-economic data about specific industrial heat generation technologies include investment costs as function of the heat load, operation & maintenance costs (OM), learning rates, and thermal efficiencies (see Table 2). Data sources used in this report stem from two sources, first, unpublished data gathered by Fraunhofer ISI in the context of the FORECAST-model project (Fleiter et al., 2018), and second, data from various other authors (Arpagaus, 2019; BMVBS, 2012; Kober et al., 2020; Wolf, 2017). The formula used to derive investment costs (in the first year) is a power function considering annual learning rates LR[7]:

$$C_{\text{invest}} = \ a \cdot Q_{\text{heat}}^{b} \cdot LR \mid LR = (1 + l)^{(t-t_0)}$$

Equation 2

with a and b as the empirically derived multiplier and exponent, $Q_{\text{heat}}$ as heat load, $l$ as assumed learning rate, $t, t_0$ as year and reference year. We adopt the corresponding values from various sources. First, the FORECAST project authors (Fleiter et al., 2018) and second, other primary sources, including (Dering, Kruse, & Vogel, 2021; Energie DK & Energi Styrelsen, 2012; Nitsch et al., 2011; U.S. Department of Energy, 2012).[8] If investment prices are reported in Euro, we convert them to CHF at an exchange rate of 1 CHF/EUR. Second, for the sake of better comparison, we assume a uniform lifetime of 20 years for all options.

#### 3.2.2 Energy price assumptions and baseline scenario

The analysis relies on prices from previous studies, published prices and own assumptions. To consider the current and local context, energy prices from the area of Basel were used to calibrate the scenario trends. We have chosen Basel due to the explicit focus of the WP on this area. Figure 4 depicts our price assumptions in the baseline scenario (see also Appendix).

Electricity prices are based on power prices from 2021 for the industry, namely the so called C7[9] profile from IWB (Elcom, 2023). The natural gas and biogas price is based on prices from 2021 for large power demand ("XL" from IWB). The load dependent grid fee is not considered as it is comparably low[10].

[7] Which depend on the year rather than the installed capacity in this simplified estimation.
[8] Parameters are yet to be published by the authors of FORECAST. However, we can provide aggregated results.
[9] According to SFOE, C7 defines a large-scale operation with 7'500'000 kWh/year and a maximal demanded power of 1'630 kW, medium voltage, and own transformer station.
[10] With energy costs of around 1600 CHF/kW, the NG grid fee ("Grundpreis") is about 1% of the yearly energy costs.

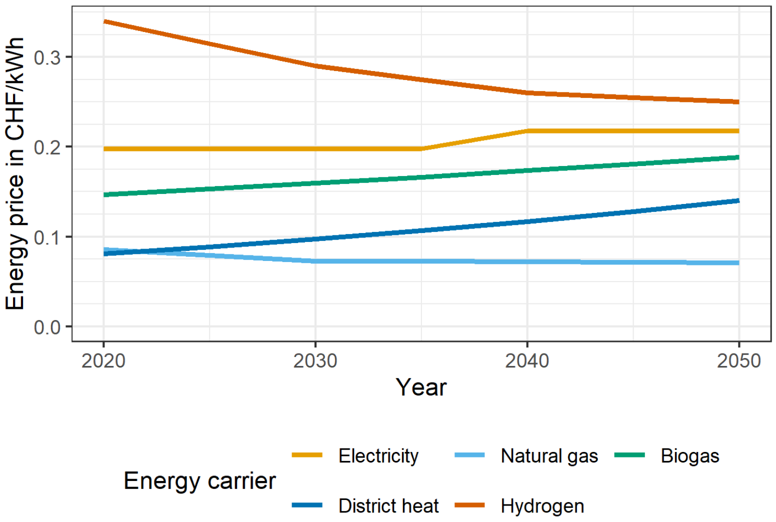


Figure 4: Energy price assumptions. Excluding VAT.

We have adopted the natural gas price development from previous work in SURE (Panos et al., 2022). Panos et al., in turn, base their assumptions on natural gas prices from the world energy outlook (OECD / IEA, 2022). Here, we use one of their NG-price trends[11] to calibrate the initial NG prices (see Table 4).

Table 4: International NG wholesale prices (Evangelos et al., 2022; OECD / IEA, 2022) .

| SURE Scenario | International wholesale prices (CH-Rp. (2021)/kWh) | | | |
|---|---|---|---|---|
| | 2021 | 2030 | 2040 | 2050 |
| SPS1 | 3.01 | 1.46 | 1.33 | 1.20 |

These price assumptions reflect a situation before the energy crisis in 2022/2023, and hence do not consider the very high NG prices seen in these years. At the time of writing this report, natural gas prices have recovered to low “pre-crisis” prices, suggesting that the energy prices of 2021 are a reasonable baseline for our calculations. Furthermore, the net-zero scenarios of IEA have very low natural gas price projections. While they account for the energy crisis until 2025, they assume low NG demand afterwards due to RePowerEU in Europe (European Commission, 2022).

Natural gas is subject to a $CO_2$-tax in all years. However, carbon intensive industries can be exempted from the tax if they commit to reducing their GHG emissions in return or if they are part of the emission trading system. We do not account for these possibilities but instead provide a $CO_2$-tax sensitivity analysis.

The energy price developments of biogas, district heat and electricity are based on own and adapted assumptions and forecasts from Switzerland-focused studies, namely from a study on the decarbonization of the heating sector (Jakob et al., 2020), the Energy Perspectives 2050+ (EP2050+) and the excurse on hydrogen (BFE, 2020, 2022b), and a report on climate policy (Iten et al., 2017).

As future energy price changes cannot be foreseen, we provide different price sensitivity analyses for energy price components (see Section **Fehler! Verweisquelle konnte nicht gefunden werden.**). In a future update of this deliverable D15.1, updated energy prices from the SWEET SURE project may be used in order to harmonise the results between the work packages.

[11] From the scenario SPS1, team sprint.

### 3.2.3 Energy price sensitivity analyses

A previous sensitivity analysis by Arpagaus (2019) finds that the economic feasibility, there expressed as an economic threshold of the temperature difference $\Delta T_{Hub}$, depends strongly on some of the input parameters. He has identified the key parameters to be the gas price, electricity-to-gas price ratio, efficiency factors, and full load hours. Investment costs of the HTHP show less effect, and discount rates, investment costs of the gas boilers and O&M have only a minor impact.

It is reasonable to assume that these sensitivities also apply to the resulting GHG-abatement costs in our analysis. To quantify the specific sensitivities, we focus on the key factors, namely price and full load hours. We do not further investigate the sensitivity of efficiency factors because empirical data is mainly available for 45% (see Equation 1). The levels of variation, units and the reasoning behind the variations are listed in **Fehler! Verweisquelle konnte nicht gefunden werden.**.

Table 5: Overview of sensitivity analyses and analysed values.

| Parameter | Unit | Affected carrier | Base-line | Sens. 1 | Sens. 2 | Reasoning |
|---|---|---|---|---|---|---|
| **International gas price** | Increase Rp / kWh | NG, BG | +0 | +2 | +4 | Baseline based on level in 2021 and future WEO expectations. Sens. 1 and 2 consider potential increased gas demand, mainly affecting NG, but also BG. |
| **$CO_2$-tax on natural gas** | Rp / kgCO2 | NG | 2.8 | 4.6 | 9.2 | Baseline level in 2022 is 120 CHF/t$CO_2$. Sens. 1 and 2 consider stricter policies and taxes of 200 and 400 CHF/t$CO_2$. |
| **Electricity-to-natural-gas price ratio** | Factor to multiply CHF/kWh electricity | Elec | 1x | 0.67x | 1.5x | Baseline based on energy prices in 2021. Other Sens. vary the electricity prices to reflect potential market trend. |

The resulting sensitivity scenarios provide value to this deliverable because they affect the energy price ratio between NG and electricity, the electricity-to-gas price ratio (Table 6). This ratio has a strong effect on the competitiveness and cost-effectiveness of heating technologies like high temperature heat pumps (HTHP) in industry (Thiel & Stark, 2021). Notably, if NG prices increase relative to the electricity price, PtH become more competitive. In the past, the electricity-to-gas price ratios have strongly differed between countries in Europe. For example, the ratio in the EU was 3.8, in Switzerland 2.5, and in Sweden 1.7 (Arpagaus, 2019). Our sensitivity analysis covers this range, with a baseline assumption mostly valid for the Swiss context. With the current trend to higher gas prices in relation to electricity prices, these ratios are bound to further decrease. Table 6 lists the final energy price ratios.

Table 6: Average energy price ratios [CHF/$kWh_{carrier\_1}$] / [CHF/$kWh_{NG}$] of the energy carrier relative to natural gas.

| Carrier 1 | Rel. to | Baseline | Carbon tax sens 1 | Carbon tax sens 2 | Elec-gas ratio sens 1 | Elec-gas ratio sens 2 | Gas price sens 1 | Gas price sens 2 |
|---|---|---|---|---|---|---|---|---|
| **Biogas** | NG | 2.1 | 1.8 | 1.2 | 2.1 | 2.1 | 1.8 | 1.6 |
| **District heat** | NG | 1.5 | 1.2 | 0.8 | 1.5 | 1.5 | 1.2 | 1 |
| **Electricity** | NG | 2.6 | 2.1 | 1.4 | 1.7 | 3.8 | 2.1 | 1.7 |
| **Hydrogen** | NG | 3.2 | 2.7 | 1.8 | 2.2 | 4.9 | 2.6 | 2.2 |

### 3.2.4 GHG-emission factors

To analyse the cost-effectiveness of heat decarbonisation options, we compare yearly costs to the associated carbon emissions. For this, we weigh the final energy use of the energy carriers with their emission factors. We adopt the factors from various sources shown in Table 7, which are valid for the Swiss context. For the future factors in 2035 and 2050, we rely on own and EP2050+ assumptions. For the latter, we choose the business-as-usual scenarios (WWB) to analyse the cost-effectiveness of electricity-based options under conservative assumptions. GHG-savings from electricity-based and district heating options will be lower if more ambitious pathways can be followed. Losses and emissions of the refrigerants are not considered in this analysis but may occur in reality.

We propose a GHG-factor for hydrogen, assuming that it is produced by electrolysis with an average efficiency of 72% $kWh_{el}/kWh_{H2}$, according to the EP2050+ excurse on hydrogen (BFE, 2022b). The Swiss consumer mix provides the basis for the electrolysis.

Table 7: GHG-emission factors for 2020 based on (Alig, Tschümperlin, & Frischknecht, 2017; BFE, 2022b; Gross, 2018; KBOB, 2022; Krebs & Frischknecht, 2021). Factors in 2035 and 2050 are based on own assumptions and simulation results from EP2050+ (Prognos, TEP Energy, Infras, & Ecoplan, 2021).

| Energy Carrier | GHG-factor [kg $CO_2$-eq/kWh] | | | Description |
|---|---|---|---|---|
| | **2020** | **2035** | **2050** | |
| **Natural gas** | 0.230 | 0.230 | 0.230 | Natural Gas (KBOB 41.002) |
| **Biogas** | 0.124 | 0.124 | 0.124 | Biogas (KBOB 41.009) |
| **District heat** | 0.071 | 0.092 | 0.116 | Average Swiss grid mix. WWB scenario. |
| **Electricity** | 0.097 | 0.066 | 0.057 | Based on Swiss consumer mix. WWB scenario. |
| **Hydrogen** | 0.135 | 0.092 | 0.079 | Hydrogen production with electrolysis from consumer mix and an efficiency of 72%. |

Overall, the GHG-factors depend on several different parameters. Most notably, the used power mix strongly affects the emission factors of electricity and hydrogen (if electrolysis is used). If power is directly converted from renewable and low-carbon electricity, the GHG-factor for hydrogen will be considerably lower (Tschümperlin & Frischknecht, 2017).

### 3.2.5 Cost and cost-effectiveness calculations

Cost calculations follow standard economic methods. Yearly costs are calculated using the annuity method (representing an equivalent annual payment, see Section 4 for input costs and emissions). For this, payments have been distributed over a period of 20 years. In the investment year, year 0, no energy costs flows are accounted. The 20-year period corresponds to the average lifetime of most industrial heating systems in this report. However, the cost-effectiveness differs from system to system and manufacturer to manufacturer. For instance, the Swiss OEM of HTHP estimated the lifetime of their (district heating) machines to more than 60 years.

All future costs are discounted using a discount factor of 8%. Overall, this factor is comparably high, however, discount factors only have a minor effect on the economic feasibility compared to other parameters such as the energy price level (Arpagaus, 2019).

GHG emissions are derived from the multiplication of final energy demand and GHG emission factors. In order to indicate the effectiveness of saving GHG, we use the abatement cost method (Rehl & Müller, 2013; UNEP, 1998). Abatement costs indicate the costs of saving GHGE relative to a reference system, i.e., the decarbonisation options relative to the natural gas boiler.

Provided that the GHGE of the decarbonisation options are smaller, the abatement costs $C_{Ai}E$ in [CHF / t CO2eq] are:

$$CE = \frac{(C_i - C_{REF})}{(E_{REF} - E_i)}$$

Equation 3

With $C_i$ and $C_{REF}$ as the yearly costs (CHF/a) of the decarbonisation options and the NG-boiler, as well as $E_{REF}$ and $E_i$ as the average yearly GHG emissions (t CO2eq/a) of the NG-boiler and the decarbonisation options. In every comparison it is assumed that the previously existing heating system, namely the NG-boiler, must be replaced (see Section 6.1).

### 3.3 Combined heat and power production

We calculate the cost-effectiveness of two combined heat and power plants (CHP). To compare these to other options, the additional power production needs to be accounted for. First, we derive the power load using a power-to-heat ratio, which we adopt from the available FORECAST model assumptions (Fleiter et al., 2018). The power-to-heat ratio describes the relation between power and heat load and production and is described as:

$$P2H = P_{heat}/P_{power}$$

Equation 4

With $P_{heat}, P_{power}$ as the heat and power load. According to the data, the P2H of fuel cells (CHP) is 0.7, and of CCGT 1.1.

Second, we assume that for separate heat and power (SHP) options, or CHP options which produce less electricity, additional electricity is purchased at the consumer electricity price (see 3.2.2). The total electricity content will be equal in every compared option. The final energy demand of CHP-options is then calculated using the efficiencies of the units (Table 8). Final results, see Section 4.4.

Table 8: Thermal and electric efficiencies of CHPs in three investment years for a heat load of 1 MW. First number denotes the thermal, second the electric efficiency.

| Technology | 2020 | 2030 | 2040 |
|---|---|---|---|
| **Combined heat and power (CHP)** | | | |
| **Fuel cell** | 0.45 / 0.32 | 0.45 / 0.32 | 0.45 / 0.32 |
| **Combined cycle gas turbine (CCGT)** | 0.41 / 0.46 | 0.41 / 0.46 | 0.41 / 0.46 |

### 3.4 Survey and validation with OEMs of HTHP

We conducted semi-structured interviews with OEMs of HTHP to learn first-hand about the general and current market environment. The interviews are a first step and an important source of information to gain insights into the willingness of industrial customers to invest in HTHP. While our interviews have already revealed some general insights, in-depth surveys with stakeholders from the utilities and industry of Basel will be conducted as part of WP15 DL15.2.

#### 3.4.1 Process and interview guideline

During this study, we contacted OEMs of HTHP in Germany and Switzerland, which are active in the global market. The aim and funding of the study was explained during the interview, additional questions were posed by e-mail or phone. Overall, two major OEMs were willing to conduct an interview. The guideline question of the general interviews focused on the market environment and the view of OEMs on their customers.

Furthermore, we have validated costs data, full load hours and lifetimes with the OEM.

1. What future challenges are your company and the industry in general facing?
2. As a manufacturer of heat pumps, what do you expect from policymakers?
3. Which competition or competing technologies play a relevant role currently and in the future?
4. What do you see as the main motivation for your customers to invest in HTHP?
5. What challenges do your customers face when switching to high-temperature heat pumps?

# 4 Economic Evaluation

## 4.1 Investment costs of SHP and CHP options

We report investment costs for seven different technologies and for investments in three different years (the cost-effectiveness analysis is solely based on investments in 2020). Figure 5 depicts specific (present value) investment costs of SHP and CHP technologies at different cost levels. Costs of water-water-HTHPs differ largely depending on the data source but are generally significantly higher than the investment costs of boilers. The cost validation with a Swiss OEM revealed that these higher cost levels are realistic, in particular if high quality standards apply. In some instances, special components like titan tubes contribute to even higher costs than the ones presented here. Due to the focus on Switzerland, we continue with high-cost assumptions (depicted as the green lines).

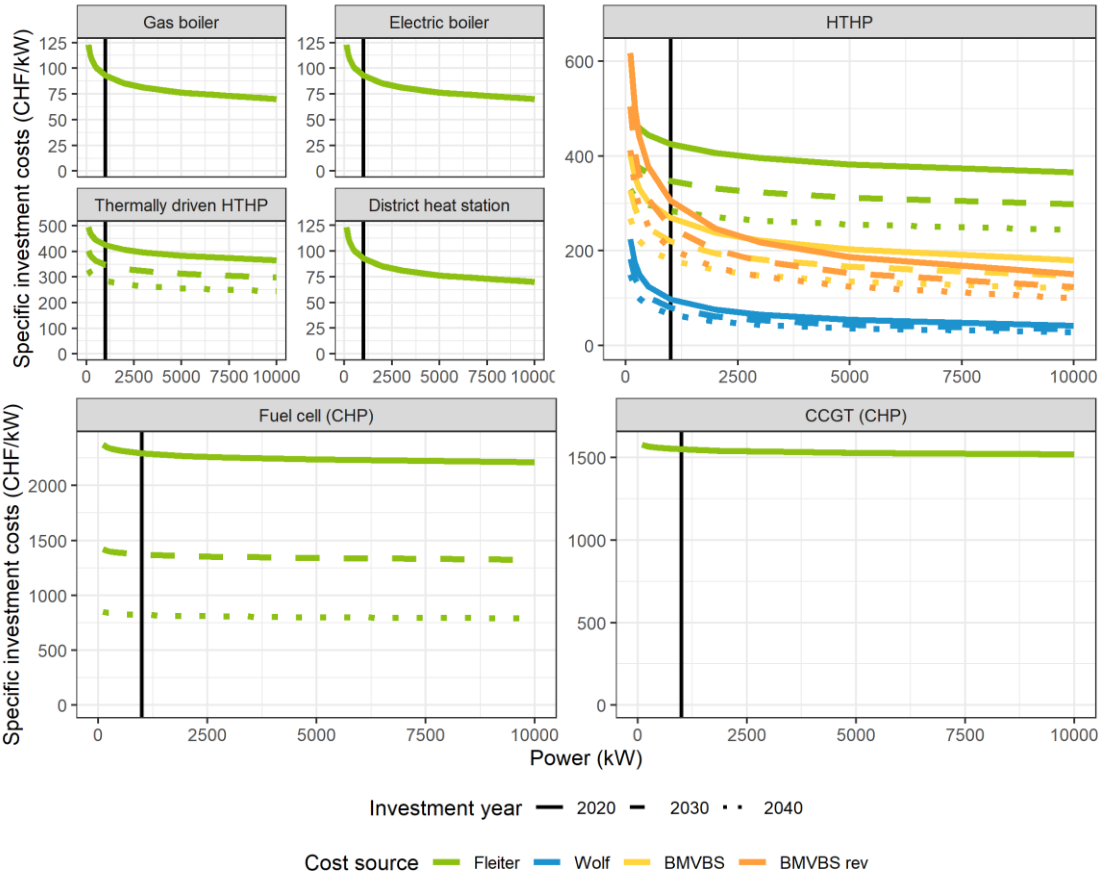


Figure 5: Specific investment costs of SHP and CHP heat decarbonisation options. Due to economy-of-scale effects, costs decrease with higher loads. Investment years represent the assumed yearly learning rates. Black bold line represents a 1MW system. Based on various sources (Arpagaus, 2019; BMVBS, 2012; Fleiter et al., 2018; Wolf, 2017).

The differences in cost levels stem from varying manufacturers, plant types, and geographic or economic areas (U.S. DOE, 2016). Due to economy-of-scale effects, specific costs decrease with increasing load (Equation 2), and due to yearly learning rates, considerable savings can be expected from fuel cells and heat pumps in the future (shown by the different line styles). For other technologies, we assume that most of the cost improvement potential is met.

The investment cost assessment does not comprise empirical data of the installation and integration costs. These costs are usually very specific to the actual use case and are hard to compare between different industries and companies (see also Section 6.1). Nevertheless, we do not neglect integration costs, but assume that the integration and installation costs are in the order of magnitude of the unit costs, especially if an optimised solution is aspired. In other words, integration costs are equal the investments costs in our calculations.

## 4.2 Operation of SHP options at full capacity of 6'000 FLH

### 4.2.1 Yearly costs in the price scenarios

A comparison of yearly costs of the different options with the NG-based boilers, a part of many existing systems, demonstrates that HTHP, thermally driven HTHP and district heating stations are relatively competitive (Figure 6). Gas boilers with hydrogen and biogas, and electric boilers are the most expensive options. Unless they can provide other benefits (e.g., P2H or storage), they are not competitive.

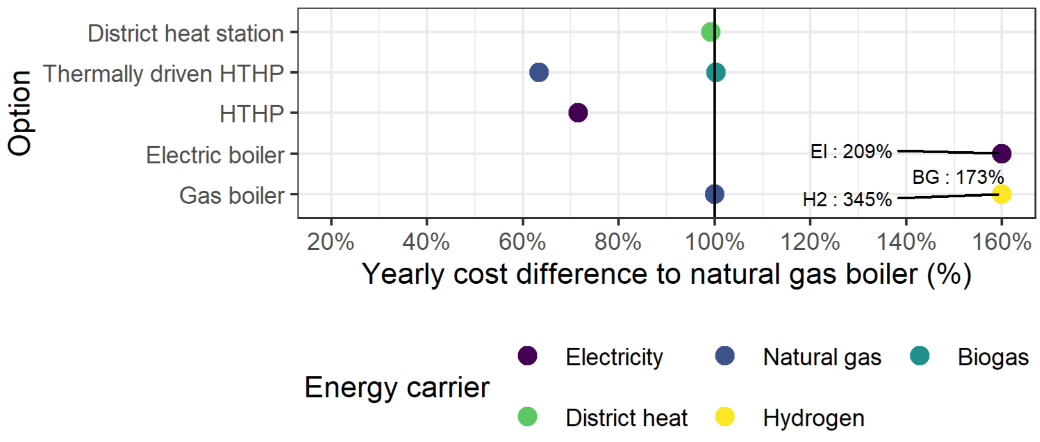


Figure 6: Differences in yearly costs between different SHP options, relative to the yearly costs of the NG-based boiler. Delta T = 50K for HPs. Load of 1 MW and annual heating demand is 6'000 MWh.

It should be noted that yearly costs are strongly dominated by the costs of the energy consumption (see Table 12 in Appendix). Reasons for this are not only our energy price assumptions, but also the high FLH of 6'000 hours. It also needs to be considered that capital costs contain the cost of one heating unit and a simplified assumption of installation and integration costs (see also Section 6.1), thus actual capital costs can deviate.

### 4.2.2 Cost-effectiveness of saving greenhouse gas emissions

The calculated GHG-emission (GHGE) savings of a 1 MW system are shown in Table 9. All considered heat decarbonisation options succeed at saving GHG-emissions compared to the NG-based boiler.

Figure 7 demonstrates the resulting GHG abatement costs (compared to a NG-based boiler) for different heat decarbonisation options and the baseline scenario. Thermally driven HTHP are the most cost-effective option to save GHGE in our comparison. This is mainly due to the low price of natural gas. However, this technology may not be suitable for all processes.

Table 9: Lifetime GHG-emissions with a heating demand of 6’000 MWh/a in scenario SPS1. Emissions and savings in kilo tons (kt). Savings compared to a NG-based boiler (absolute and relative). Only considering SHP.

| Options | Energy carrier | GHGE (kt) | GHG-saving (kt) | GHGE % |
|---|---|---|---|---|
| **Gas boiler** | Natural gas | 30.16 | 0 | 100.0% |
| **Gas boiler** | Biogas | 16.26 | 13.9 | 53.9% |
| **Thermally driven HTHP** | Natural gas | 15.24 | 14.92 | 50.5% |
| **Gas boiler** | Hydrogen | 13.92 | 16.25 | 46.1% |
| **District heat station** | District heat | 10.84 | 19.32 | 36.0% |
| **Electric boiler** | Electricity | 9.45 | 20.71 | 31.3% |
| **Thermally driven HTHP** | Biogas | 8.22 | 21.95 | 27.2% |
| **HTHP (dT:70)** | Electricity | 3.38 | 26.78 | 11.2% |
| **HTHP (dT:50)** | Electricity | 2.62 | 27.55 | 8.7% |
| **HTHP (dT:30)** | Electricity | 1.78 | 28.39 | 5.9% |
| **HTHP (dT:20)** | Electricity | 1.31 | 28.86 | 4.3% |

In general, HTHPs with low temperature differences between heat source and sink, and thus high efficiencies, exhibit negative abatement costs. An example for a low temperature difference in the food industry would be the 50 – 90 °C of waste heat created during the drying process that could be used to boil goods at temperatures of 70-120°C (ΔT= <30°C)(Arpagaus, 2019). This means, costs and GHGE can be saved compared to other options or new NG-based boilers. For instance, a 1 MW HTHP (at ΔT=30°C) is a profitable option with a return of more than 150 CHF per saved tonne of $CO_2$-equivalent.

These results underline the advantage of minimising the temperature differences. If differences are higher (e.g., ΔT=70°C), the cost advantage of HTHPs are fading. In these cases, or if HTHP cannot be integrated, other options such as thermally driven heat pumps or district heating stations could be a cost-effective alternative to mitigate GHGE. In contrast, electric boilers, gas boilers with biogas or hydrogen exhibit very high abatement costs.

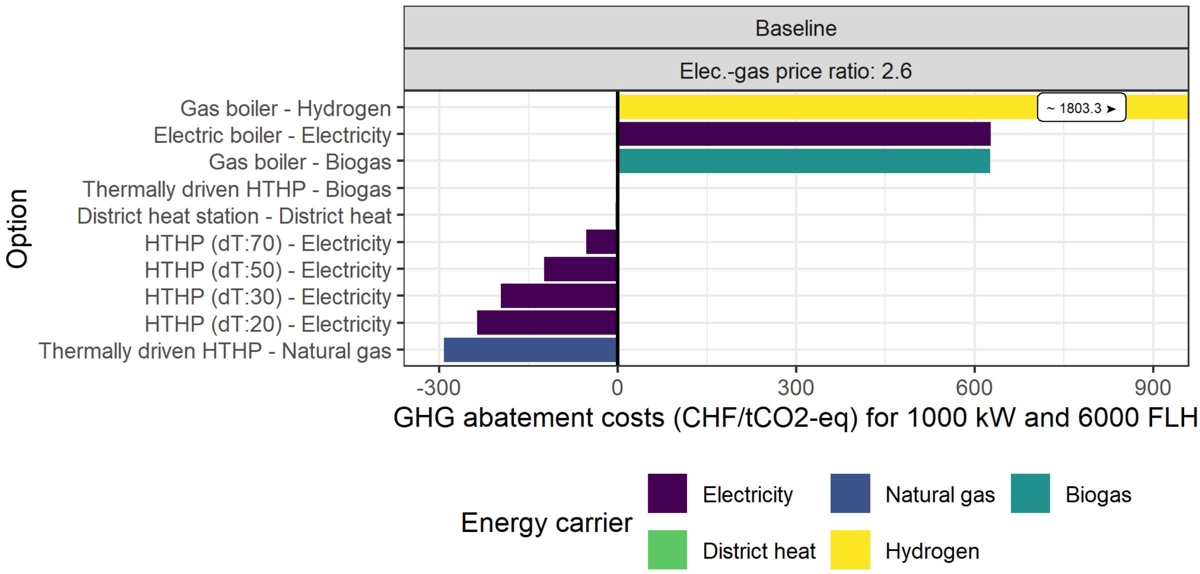


Figure 7: GHG abatement costs for 1MW SHP heat decarbonisation options in CHF per saved $tCO_2$-eq. Results for the baseline price scenario with 6’000 FLH. Comparison to a 1:1 replacement of a NG-based boiler. Negative GHG abatement costs result in cost and emission savings.

### 4.2.3 Energy price sensitivity analysis

Figure 8 depicts the GHG-abatements costs of different sensitivity scenarios. In general, the lower the electricity-to-gas price ratio, the more options are economically viable compared to a natural gas boiler.

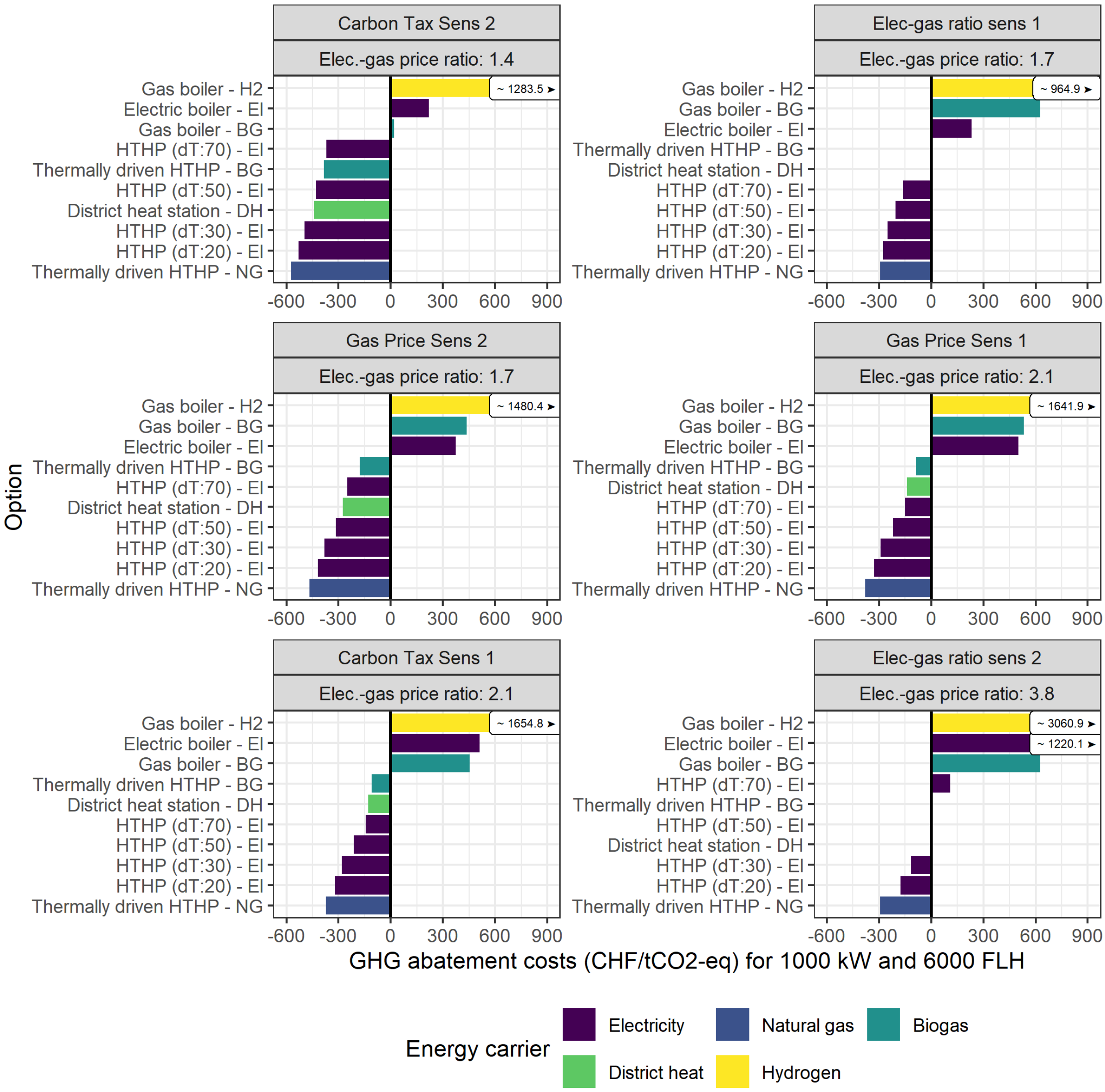


Figure 8: GHG abatement costs sensitivities for 1MW SHP heat decarbonisation options in CHF per saved $tCO_2$-eq. Results for sensitivity scenarios with 6’000 FLH. Comparison to a 1:1 replacement of a NG-based boiler. Negative GHG abatement costs result in cost and emission savings.

## 4.3 Operation of SHP options at partial capacity of 3'000 FLH

### 4.3.1 Yearly costs in the price scenarios

A comparison of yearly costs at 3'000 FLH demonstrates that HTHP, thermally driven HTHP and district heating stations are still competitive in the four scenarios (Figure 9). However, compared to 6'000 FLH, the cost advantage between these options decreases (Figure 6 vs Figure 9). Furthermore, the share of energy costs on yearly costs decreases, making the cost of capital more significant for industries operating at fewer full load hours (see Appendix, Table 13).

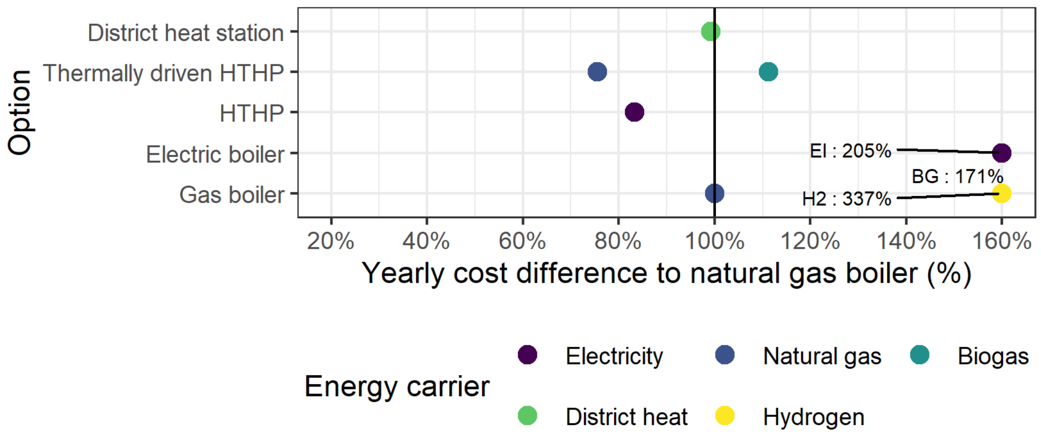


Figure 9: Differences in yearly costs between different SHP options, relative to the yearly costs of the NG-based boiler. Delta T = 50K for HPs. Load of 1 MW and annual heating demand is 3'000 MWh.

### 4.3.2 Cost-effectiveness of saving greenhouse gas emissions with 3'000 FLH

The calculated GHG-emission (GHGE) savings of a 1 MW system are shown in Table 10. All considered heat decarbonisation options succeed at saving GHG-emissions compared to the NG-based boiler.

Table 10: Lifetime GHG-emissions with a heating demand of 3'000 MWh/a in the baseline scenario. Emissions and savings in kilo tons (kt). Savings compared to a NG-based boiler (absolute and relative). Only considering SHP.

| Options | Energy carrier | GHGE (kt) | GHGE Delta (kt) | GHGE % |
|---|---|---|---|---|
| **Gas boiler** | Natural gas | 15.1 | 0 | 100% |
| **Gas boiler** | Biogas | 8.1 | 7 | 54% |
| **Thermally driven HTHP** | Natural gas | 7.6 | 7.5 | 51% |
| **Gas boiler** | Hydrogen | 7 | 8.1 | 46% |
| **District heat station** | District heat | 5.4 | 9.7 | 36% |
| **Electric boiler** | Electricity | 4.7 | 10.4 | 31% |
| **Thermally driven HTHP** | Biogas | 4.1 | 11 | 27% |
| **HTHP (dT:70)** | Electricity | 1.7 | 13.4 | 11% |
| **HTHP (dT:50)** | Electricity | 1.3 | 13.8 | 9% |
| **HTHP (dT:30)** | Electricity | 0.9 | 14.2 | 6% |
| **HTHP (dT:20)** | Electricity | 0.7 | 14.4 | 4% |

Figure 10 demonstrates the resulting GHG abatement costs (compared to a NG-based boiler) for different heat decarbonisation options at 3'000 FLH. Compared to 6'000 FLH, the abatement costs of most HTHP are still negative, however for high temperature differences, they are in the same order of magnitude as other options (Figure 7 vs Figure 10).

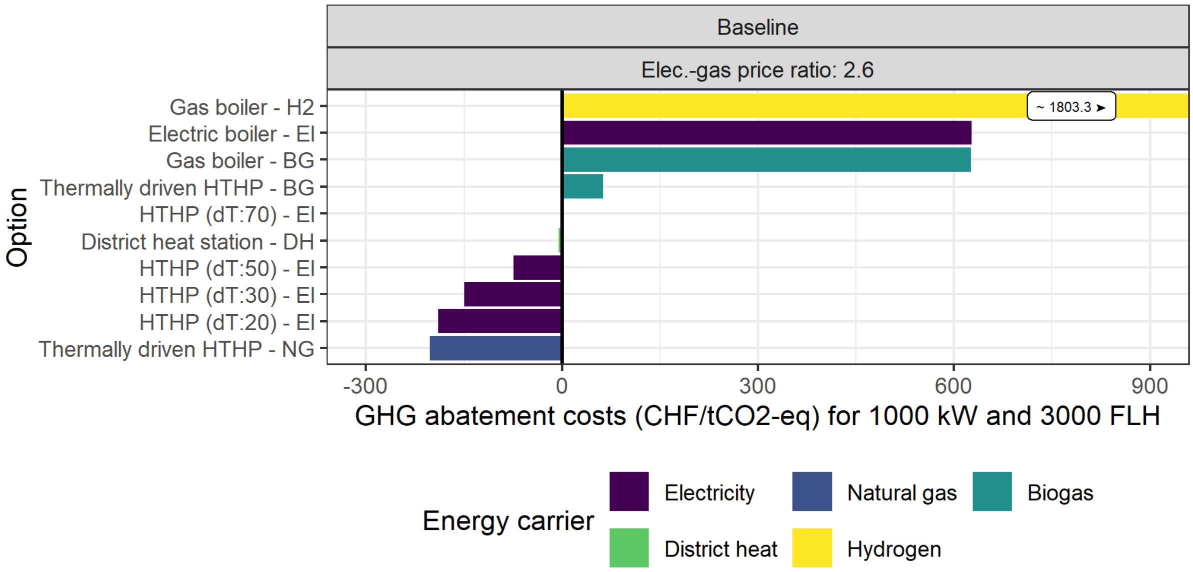


Figure 10: GHG abatement costs for 1MW SHP heat decarbonisation options in CHF per saved $tCO_2$-eq. Results for 3'000 FLH. Comparison to a 1:1 replacement of a NG-based boiler. Negative GHG abatement costs result in cost and emission savings.

### 4.4 Operation of CHP options at 6'000 FLH

#### 4.4.1 Yearly costs in the price scenarios and with 6'000 FLH and CHP

To compare CHP to SHP plants and heat suppliers, additional electricity is purchased (see Section 3.3). A comparison of yearly costs of the different options (CHP and SHP) with the NG-based boilers, which are part of existing systems, demonstrates that CHP plants tend to be more expensive (Figure 11). One exception is the NG-based CCGT option, featuring the lowest yearly costs.

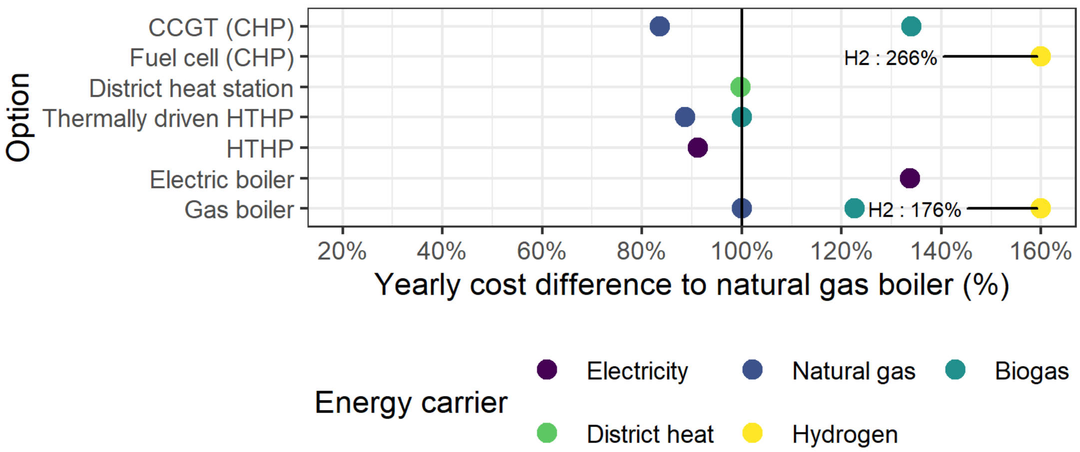


Figure 11: Differences in yearly costs between different options, relative to the yearly costs of the NG-based boiler. Delta T = 50K for HPs. Load of 1 MW and annual is 6'000 MWh. Arranged by average elec.-gas price ratio. Considering CHP and SHP systems with additionally purchased power.

### 4.4.2 Cost-effectiveness of saving greenhouse gas emissions with 6'000 FLH and CHP

The resulting GHG-Emission (GHGE) savings of 1 MW SHP and CHP systems are shown in Table 11. Most of the considered options succeed at saving GHG-emissions compared to the natural gas boiler, except CCGT with natural gas. Hence, this option is not further analysed below. The biogas CHP option does not lead to a considerable reduction of GHGE.

Table 11: Lifetime GHG-emissions with a heating demand of 6'000 MWh/a in scenario SPS1. Emissions and savings in kilo tons (kt). Savings compared to a NG-based boiler (absolute and relative). Considering CHP and SHP systems with additionally purchased power.

| Options | Energy carrier | GHGE (kt) | GHGE Delta (kt) | GHGE % |
|---|---|---|---|---|
| **CCGT (CHP)** | Natural gas | 67.2 | -26.8 | 166% |
| **Gas boiler** | Natural gas | 40.4 | 0 | 100% |
| **CCGT (CHP)** | Biogas | 36.2 | 4.1 | 90% |
| **Fuel cell (CHP)** | Hydrogen | 32.1 | 8.3 | 79% |
| **Gas boiler** | Biogas | 26.5 | 13.9 | 66% |
| **Thermally driven HTHP** | Natural gas | 25.4 | 14.9 | 63% |
| **Gas boiler** | Hydrogen | 24.1 | 16.2 | 60% |
| **District heat station** | District heat | 21.1 | 19.3 | 52% |
| **Electric boiler** | Electricity | 19.7 | 20.7 | 49% |
| **Thermally driven HTHP** | Biogas | 18.4 | 21.9 | 46% |
| **HTHP (dT:70)** | Electricity | 13.6 | 26.8 | 34% |
| **HTHP (dT:50)** | Electricity | 12.8 | 27.5 | 32% |
| **HTHP (dT:30)** | Electricity | 12 | 28.4 | 30% |
| **HTHP (dT:20)** | Electricity | 11.5 | 28.9 | 29% |

Particularly from a cost-effectiveness perspective, the CHP options are not viable options for saving GHG-emissions, as depicted in Figure 12. One major reason for this result may be the low GHGE-factors of the consumer power mix compared to the other options.

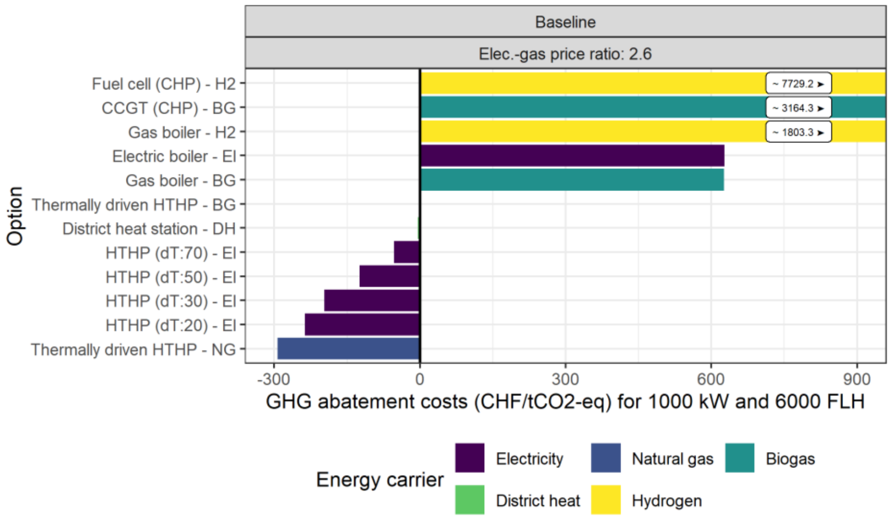


Figure 12: GHG abatement costs for 1MW CHP and SHP heat decarbonisation options in CHF per saved $tCO_2$-eq. Results for different price scenarios with 6'000 FLH. Comparison to a 1:1 replacement of a NG-based boiler. Negative GHG abatement costs result in cost and emission savings.

# 5 Insight from the Manufacturers

First discussions with a HTHP OEM in Germany has revealed that, in 2022, the market demand increased notably also beyond industry segments which were susceptible to this technology for mainly environmental reasons. The following, longer interview with a Swiss OEM, which has been a pioneer in the industry, confirmed this observation. Previously, their main markets were mainly municipalities in Europe and the provision of district heating. However, in 2022, the OEM has gained several new customers, both in the public and private sector (e.g., the beverage industry in the Netherlands). The main reason is the need to move away from natural gas, on the one hand, due to decisions from government and companies to decarbonise their production, on the other, due to the drastic changes and supply issues in the energy market in Europe following the Ukraine crisis in 2022.

Regarding, the current developments and competition, the Swiss OEM mainly considers other HTHP manufacturers as their competition. Competitive challenges lie in different refrigerants with varying properties, costs, and GHG-emission potentials, but also in the recruitment of trained personnel. Other PtH options like the use of hydrogen for fuel or carbon capture and storage, at least in the Swiss context, seem to be of no considerable concern.

# 6 Conclusion and Outlook

In this deliverable, we have illustrated that high temperature heat pumps (HTHP), both electric and thermally driven, are the most cost-effective heat decarbonisation option for the industrial heat supply in Switzerland and more specifically regions like Basel. This holds true under various energy price assumptions and applies to processes like steam and hot water generation, or drying, which need high useable temperatures of up to 120 °C. Nevertheless, several other options also result in lower GHGE compared to natural gas-based boilers.

Despite these prospects, barriers are the limited upper heating levels and integration costs. The latter pose challenges due to the heterogenous processes across different industries and sectors. We assumed that the integration costs lie in the same range of the investment costs, but in practice cost may be higher and a potential reason to use other means of heat decarbonisation. However, as energy costs are the dominating factor in the cost-effectiveness calculation, integration costs would need to be several factors higher than installations costs.

Overall, market demand from the industrial sector is increasing due to changing energy prices and the need to decarbonise production. OEMs thus expect that the deployment of process heating decarbonisation options in the industry will increase in the coming years.

## 6.1 Limitations

While the deliverable provides regional-context and scenario-based insights into the economic potential of various heat decarbonisation options, extending the literature, there are some caveats which may be addressed in future work.

One limitation is that only the capital costs of one single 1MW unit is considered. First, higher load would only lead to savings of investment costs, due to economy of scale. However, the largest cost component, the energy costs increase proportionally. Second, other investment and capital costs such as the integration and installation costs, structural measures, work on the exhaust pipes, distribution of residual process heat and fees for the workforce are not considered. In the residential sector, these costs contribute significantly to the total costs (Jakob et al., 2023). However, most of the sectors are more heterogenous than the residential sector, and thus, costs for installation could vary significantly in different industries and companies. Tallying these costs in upcoming studies could be important, as the lack of standardised solutions is one of the major barriers of decarbonising the industry sector.

Second, we consider waste heat to be free of charge. This assumption applies to industries and companies in which waste heat is freely available from other processes. In principle, external sources of heat could come at a certain cost, such as district heat. However, such costs are not considered here. Third, other heat sources such as geothermal energy is not fully considered.

Fourth, the representation of carbon taxes is superficial. To improve the evaluation, it should be differentiated between companies who are exempted from these taxes but instead participate in the emission trading system or market.

Finally, the case of substituting fossil fuel for low-carbon fuel is not explicitly considered. In every evaluation, we assume that a new unit will be installed. If low-carbon fuel would be directly used in existing boilers, the annual costs for e.g., biogas boilers would be lower. In the case of a substitution, stranded costs should however be considered. Overall, we suggest that this limitation on our results is small because energy prices dominate yearly costs for large (1MW) units.

### 6.2 Outlook

In D15.2, due 2024, we will take a closer look at the preferences of industrial customers in Basel. The goal, among others, will be to assess the adoption potential, barriers and trade-offs, technical and operational pre-requisites, required payback periods and willingness to pay for heat decarbonisation options. For this, we will conduct interviews and quantitative surveys with stakeholders from the industry.

Support or subsidies for HTHP may be needed (IEA, 2022a). Therefore, in D15.3., insights from D15.1 and D15.2 are synthesised in order to propose policy options which foster the process heat decarbonisation. Evidence gained in WP15 about industrial energy consumption and efficiency and decarbonation options will be made available to the integrated system model (WP7) and to the energy demand modelling (WP4).

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# 8 Appendices

## 8.1 Yearly cost tables

Table 12, Table 13 and Table 14 show the yearly costs per kW of the all the considered options and scenarios for 6'000 and 3'000 FLH, respectively. Energy costs depend on the respective price scenario, capital and integration costs are assumed to be in the same order of magnitude, i.e. here the same, and O&M costs are a share of the capital costs, but mostly very low in comparison. Finally, Table 15 shows the used energy prices.

Table 12: Yearly specific costs (CHF/kW). Payment period of 20 years. Standard cost estimate, valid for 1MW systems in the investment year 2020. Heating demand at 6'000 MWh. Delta T for HTHP = 50K.

| Option | Energy carrier | Cost type | Yearly costs in scenarios (CHF / kW) for 6'000 FLH | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | Base-line | Gas Price Sens 1 | Gas Price Sens 2 | Car-bon Tax Sens 1 | Car-bon Tax Sens 2 | Elec-gas ratio sens 1 | Elec-gas ra-tio sens 2 |
| **Electric boiler** | Electric-ity | Energy costs | 1228.1 | 1228.1 | 1228.1 | 1228.1 | 1228.1 | 818.7 | 1842.2 |
| **Electric boiler** | Electric-ity | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Electric boiler** | Electric-ity | O&M costs | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| **Electric boiler** | Electric-ity | Integra-tion costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Biogas | Energy costs | 1013.6 | 1079.2 | 1144.8 | 1013.6 | 1013.6 | 1013.6 | 1013.6 |
| **Gas boiler** | Biogas | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Biogas | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Gas boiler** | Biogas | Integra-tion costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Natural gas | Energy costs | 578.3 | 709.5 | 840.6 | 699.0 | 1000.6 | 578.3 | 578.3 |
| **Gas boiler** | Natural gas | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Natural gas | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Gas boiler** | Natural gas | Integra-tion costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Hydro-gen | Energy costs | 2043.3 | 2043.3 | 2043.3 | 2043.3 | 2043.3 | 1362.2 | 3065.0 |
| **Gas boiler** | Hydro-gen | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Hydro-gen | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Gas boiler** | Hydrogen | Integration costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **District heat station** | District heat | Energy costs | 574.3 | 574.3 | 574.3 | 574.3 | 574.3 | 574.3 | 574.3 |
| **District heat station** | District heat | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **District heat station** | District heat | O&M costs | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| **District heat station** | District heat | Integration costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **HTHP** | Electricity | Energy costs | 340.3 | 340.3 | 340.3 | 340.3 | 340.3 | 226.8 | 510.4 |
| **HTHP** | Electricity | Capital costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **HTHP** | Electricity | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **HTHP** | Electricity | Integration costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **Thermally driven HTHP** | Biogas | Energy costs | 512.1 | 545.2 | 578.4 | 512.1 | 512.1 | 512.1 | 512.1 |
| **Thermally driven HTHP** | Biogas | Capital costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **Thermally driven HTHP** | Biogas | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Thermally driven HTHP** | Biogas | Integration costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **Thermally driven HTHP** | Natural gas | Energy costs | 292.2 | 358.4 | 424.7 | 353.1 | 505.5 | 292.2 | 292.2 |
| **Thermally driven HTHP** | Natural gas | Capital costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **Thermally driven HTHP** | Natural gas | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Thermally driven HTHP** | Natural gas | Integration costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |

Table 13: Yearly specific costs (CHF/kW). Payment period of 20 years. Standard cost estimate, valid for 1MW systems in the investment year 2020. Heating demand at 3'000 MWh. Delta T for HTHP = 50K.

| Option | Energy carrier | Cost type | Yearly costs in scenarios (CHF / kW) for 3'000 FLH | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | Base-line | Gas Price Sens 1 | Gas Price Sens 2 | Car-bon Tax Sens 1 | Car-bon Tax Sens 2 | Elec-gas ratio Sens 1 | Elec-gas ratio Sens 2 |
| **Electric boiler** | Electricity | Energy costs | 614.1 | 614.1 | 614.1 | 614.1 | 614.1 | 409.4 | 921.1 |
| **Electric boiler** | Electricity | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Electric boiler** | Electricity | O&M costs | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| **Electric boiler** | Electricity | Integra-tion costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Biogas | Energy costs | 506.8 | 539.6 | 572.4 | 506.8 | 506.8 | 506.8 | 506.8 |
| **Gas boiler** | Biogas | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Biogas | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Gas boiler** | Biogas | Integra-tion costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Natural gas | Energy costs | 289.2 | 354.7 | 420.3 | 349.5 | 500.3 | 289.2 | 289.2 |
| **Gas boiler** | Natural gas | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Natural gas | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Gas boiler** | Natural gas | Integra-tion costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Hydrogen | Energy costs | 1021.7 | 1021.7 | 1021.7 | 1021.7 | 1021.7 | 681.1 | 1532.5 |
| **Gas boiler** | Hydrogen | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Hydrogen | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Gas boiler** | Hydrogen | Integra-tion costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **District heat sta-tion** | District heat | Energy costs | 287.1 | 287.1 | 287.1 | 287.1 | 287.1 | 287.1 | 287.1 |
| **District heat sta-tion** | District heat | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **District heat station** | District heat | O&M costs | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| **District heat station** | District heat | Integration costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **HTHP** | Electricity | Energy costs | 170.1 | 170.1 | 170.1 | 170.1 | 170.1 | 113.4 | 255.2 |
| **HTHP** | Electricity | Capital costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **HTHP** | Electricity | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **HTHP** | Electricity | Integration costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **Thermally driven HTHP** | Biogas | Energy costs | 256.1 | 272.6 | 289.2 | 256.1 | 256.1 | 256.1 | 256.1 |
| **Thermally driven HTHP** | Biogas | Capital costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **Thermally driven HTHP** | Biogas | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Thermally driven HTHP** | Biogas | Integration costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **Thermally driven HTHP** | Natural gas | Energy costs | 146.1 | 179.2 | 212.4 | 176.6 | 252.8 | 146.1 | 146.1 |
| **Thermally driven HTHP** | Natural gas | Capital costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **Thermally driven HTHP** | Natural gas | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Thermally driven HTHP** | Natural gas | Integration costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |

Table 14: Yearly specific costs (CHF/kW), including CHP systems. Payment period of 20 years. Standard cost estimate, valid for 1MW systems in the investment year 2020. Heating demand at 3'000 MWh. Delta T for HTHP = 50K.

| **Option** | **Energy carrier** | **Cost type** | **Yearly costs in scenarios (CHF / kW) for 6'000 FLH** | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | Baseline | Gas Price Sens 1 | Gas Price Sens 2 | Carbon Tax Sens 1 | Carbon Tax Sens 2 | Elec-gas ratio Sens 1 | Elec-gas ratio Sens 2 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **CCGT (CHP)** | Biogas | Energy costs | 2258.7 | 2404.8 | 2550.9 | 2258.7 | 2258.7 | 2258.7 | 2258.7 |
| **CCGT (CHP)** | Biogas | Capital costs | 157.8 | 157.8 | 157.8 | 157.8 | 157.8 | 157.8 | 157.8 |
| **CCGT (CHP)** | Biogas | O&M costs | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 |
| **CCGT (CHP)** | Biogas | Integra-tion costs | 157.8 | 157.8 | 157.8 | 157.8 | 157.8 | 157.8 | 157.8 |
| **CCGT (CHP)** | Natu-ral gas | Energy costs | 1288.7 | 1580.9 | 1873.2 | 1557.6 | 2229.7 | 1288.7 | 1288.7 |
| **CCGT (CHP)** | Natu-ral gas | Capital costs | 157.8 | 157.8 | 157.8 | 157.8 | 157.8 | 157.8 | 157.8 |
| **CCGT (CHP)** | Natu-ral gas | O&M costs | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 |
| **CCGT (CHP)** | Natu-ral gas | Integra-tion costs | 157.8 | 157.8 | 157.8 | 157.8 | 157.8 | 157.8 | 157.8 |
| **Fuel cell (CHP)** | Hydro-gen | Energy costs | 4647.6 | 4647.6 | 4647.6 | 4647.6 | 4647.6 | 3098.4 | 6971.4 |
| **Fuel cell (CHP)** | Hydro-gen | Capital costs | 233.5 | 233.5 | 233.5 | 233.5 | 233.5 | 233.5 | 233.5 |
| **Fuel cell (CHP)** | Hydro-gen | O&M costs | 11.7 | 11.7 | 11.7 | 11.7 | 11.7 | 11.7 | 11.7 |
| **Fuel cell (CHP)** | Hydro-gen | Integra-tion costs | 233.5 | 233.5 | 233.5 | 233.5 | 233.5 | 233.5 | 233.5 |
| **Electric boiler** | Elec-tricity | Energy costs | 2554.8 | 2554.8 | 2554.8 | 2554.8 | 2554.8 | 1703.2 | 3832.2 |
| **Electric boiler** | Elec-tricity | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Electric boiler** | Elec-tricity | O&M costs | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| **Electric boiler** | Elec-tricity | Integra-tion costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Biogas | Energy costs | 2340.4 | 2405.9 | 2471.5 | 2340.4 | 2340.4 | 1898.1 | 3003.7 |
| **Gas boiler** | Biogas | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Biogas | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Gas boiler** | Biogas | Integra-tion costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Natu-ral gas | Energy costs | 1905.1 | 2036.2 | 2167.4 | 2025.7 | 2327.4 | 1462.8 | 2568.4 |
| **Gas boiler** | Natu-ral gas | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Gas boiler** | Natural gas | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Gas boiler** | Natural gas | Integration costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Hydrogen | Energy costs | 3370.0 | 3370.0 | 3370.0 | 3370.0 | 3370.0 | 2246.7 | 5055.1 |
| **Gas boiler** | Hydrogen | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **Gas boiler** | Hydrogen | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Gas boiler** | Hydrogen | Integration costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **District heat station** | District heat | Energy costs | 1901.0 | 1901.0 | 1901.0 | 1901.0 | 1901.0 | 1458.8 | 2564.4 |
| **District heat station** | District heat | Capital costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **District heat station** | District heat | O&M costs | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| **District heat station** | District heat | Integration costs | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| **HTHP** | Electricity | Energy costs | 1667.0 | 1667.0 | 1667.0 | 1667.0 | 1667.0 | 1111.3 | 2500.5 |
| **HTHP** | Electricity | Capital costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **HTHP** | Electricity | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **HTHP** | Electricity | Integration costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **Thermally driven HTHP** | Biogas | Energy costs | 1838.8 | 1871.9 | 1905.1 | 1838.8 | 1838.8 | 1396.6 | 2502.2 |
| **Thermally driven HTHP** | Biogas | Capital costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **Thermally driven HTHP** | Biogas | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Thermally driven HTHP** | Biogas | Integration costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Thermally driven HTHP** | Natu-ral gas | Energy costs | 1618.9 | 1685.2 | 1751.4 | 1679.9 | 1832.3 | 1176.7 | 2282.3 |
| **Thermally driven HTHP** | Natu-ral gas | Capital costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **Thermally driven HTHP** | Natu-ral gas | O&M costs | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| **Thermally driven HTHP** | Natu-ral gas | Integra-tion costs | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |

Table 15: Energy price scenarios, in CHF / kWh. excluding VAT.

| Energy carrier | Scenario | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|
| **Natural gas** | Baseline | 0.09 | 0.09 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| **Electricity** | Baseline | 0.2 | 0.2 | 0.2 | 0.2 | 0.22 | 0.22 | 0.22 |
| **District heat** | Baseline | 0.08 | 0.09 | 0.1 | 0.11 | 0.12 | 0.13 | 0.14 |
| **Biogas** | Baseline | 0.15 | 0.15 | 0.16 | 0.17 | 0.17 | 0.18 | 0.19 |
| **Hydrogen** | Baseline | 0.34 | 0.32 | 0.29 | 0.28 | 0.26 | 0.26 | 0.25 |
| **Natural gas** | Carbon Tax Sens 1 | 0.11 | 0.11 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| **Electricity** | Carbon Tax Sens 1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.22 | 0.22 | 0.22 |
| **District heat** | Carbon Tax Sens 1 | 0.08 | 0.09 | 0.1 | 0.11 | 0.12 | 0.13 | 0.14 |
| **Biogas** | Carbon Tax Sens 1 | 0.15 | 0.15 | 0.16 | 0.17 | 0.17 | 0.18 | 0.19 |
| **Hydrogen** | Carbon Tax Sens 1 | 0.34 | 0.32 | 0.29 | 0.28 | 0.26 | 0.26 | 0.25 |
| **Natural gas** | Carbon Tax Sens 2 | 0.16 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.14 |
| **Electricity** | Carbon Tax Sens 2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.22 | 0.22 | 0.22 |
| **District heat** | Carbon Tax Sens 2 | 0.08 | 0.09 | 0.1 | 0.11 | 0.12 | 0.13 | 0.14 |
| **Biogas** | Carbon Tax Sens 2 | 0.15 | 0.15 | 0.16 | 0.17 | 0.17 | 0.18 | 0.19 |
| **Hydrogen** | Carbon Tax Sens 2 | 0.34 | 0.32 | 0.29 | 0.28 | 0.26 | 0.26 | 0.25 |
| **Natural gas** | Elec-gas ratio sens 1 | 0.09 | 0.09 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| **Electricity** | Elec-gas ratio sens 1 | 0.13 | 0.13 | 0.13 | 0.13 | 0.15 | 0.15 | 0.15 |
| **District heat** | Elec-gas ratio sens 1 | 0.08 | 0.09 | 0.1 | 0.11 | 0.12 | 0.13 | 0.14 |
| **Biogas** | Elec-gas ratio sens 1 | 0.15 | 0.15 | 0.16 | 0.17 | 0.17 | 0.18 | 0.19 |
| **Hydrogen** | Elec-gas ratio sens 1 | 0.23 | 0.21 | 0.19 | 0.18 | 0.17 | 0.17 | 0.17 |