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TECHNO-ECONOMIC OPTIMIZATION OF POWER-TO-HEAT SYSTEMS WITH THERMAL ENERGY STORAGE ACROSS DIFFERENT CONFIGURATIONS

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Summary

The electrification of industrial heat demand is a key element of the pathway toward industrial decarbonization. This study investigates a range of system configurations based on a power to heat system with integrated molten salt two-tank thermal energy storage (P2H-TES) as the core technology. A techno-economic optimization model was developed to assess twelve system configurations, including hybridized arrangements with a gas boiler, a photovoltaic system, or both. The analysis focuses on the German market, with particular attention to the grid fee structure applied in Baden-Württemberg, which is incorporated into the optimization and the calculation of key performance indicators (KPIs). The economic performance of each configuration is evaluated using the levelized cost of heat, cash flow analysis, payback period, and the share of electricity in heat generation. The results show that a hybrid system combining an optimally sized gas boiler and photovoltaic system, while benefiting from atypical grid usage discounts, achieves the lowest levelized cost of heat and the shortest payback period, outperforming a standalone gas boiler over the system lifetime from 2026 to 2050, although this comes with the trade-off of high upfront CAPEX.

Keywords: Mathematical modeling, P2H-TES, heat electrification, decarbonization, techno-economic optimization, future scenario analysis

Field of application for the findings: Industrial medium-temperature process heat, thermal storage, hybrid P2H/gas steam supply

Addressed audience: Energy system modelers, industrial heat engineers, project developers, utilities, and policy analysts

1. Introduction

Accelerating the decarbonization of industry is a key requirement if the European Union is to meet its energy transition objectives. Industry accounted for roughly 24.6 % of EU final energy demand in 2023, of which fossil fuels represented 48.7 %; electricity and heat covered 33 % and 5 % respectively, although both of these carriers were themselves still produced predominantly from fossil sources (Eurostat, 2025). As a result, industrial activities generated 19.9 % of the EU's greenhouse gas (GHG) emissions in that same year (So, 2026). The International Renewable Energy Agency (IRENA) likewise notes that heat supply worldwide continues to depend strongly on coal, oil, and natural gas, positioning smart electrification as a central lever for decarbonizing heating and cooling (International Renewable Energy Agency IRENA, n.d.). Substituting fossil fuels with electricity drawn largely from renewable sources therefore represents one viable route to a low-carbon industrial sector, while also contributing to more predictable energy costs by reducing reliance on imported fuels whose prices have been volatile in recent years. A persistent obstacle, however, is that electricity is often more expensive than natural gas at prevailing market prices, although this comparison does not account for the external costs associated with fossil fuel use.

Because renewable generation technologies operate at very low marginal costs, they push down the market clearing price determined by the merit order curve (Next Kraftwerke, n.d.). A growing renewable share in the generation mix should consequently translate into lower electricity prices over time. Regarding greenhouse gas pricing, an Enerdata analysis anticipates that the EU Emissions Trading System (EU ETS) price will hold relatively steady at about 70-75 EUR/tCO_2 through 2030, before climbing to roughly 130 EUR/tCO_2 by 2040 and surpassing 500 EUR/tCO_2 by 2044 (Enerdata, 2023). For comparison, the natural-gas price assumed in this study for 2044, 0.075 EUR/kWh, is equivalent to a carbon price of approximately 373 EUR/tCO_2. Factoring in such prospective price developments reinforces the case for investigating electrification-driven decarbonization options and the long-term cost savings they may deliver.

This study investigates whether molten-salt-based P2H-TES systems can reduce the cost of electrifying industrial process steam at 180-250 °C compared with a standalone gas boiler. The analysis considers both standalone and hybrid configurations and evaluates how storage, gas-boiler backup, photovoltaic generation, and grid-fee rules affect techno-economic performance. A techno-economic optimization model is developed to identify cost-minimal sizing and operation strategies across twelve system configurations.

Germany is used as the geographic location of the case study because it hosts substantial energy-intensive industrial production, has a large and increasingly renewable electricity system, and applies grid-fee structures that strongly affect electrified heat supply. The analysis focuses on a medium-voltage industrial consumer in Baden-Württemberg and explicitly includes both energy- and capacity-related grid fees.

Using historical price data and future price projections, this study investigates the techno-economic performance of optimized P2H-TES systems for industrial heat supply. It assesses how component sizing and dispatch strategies, atypical grid usage discounts, on-site PV integration, and different load profiles affect the levelized cost of heat (LCOH), cash flows, payback periods, and the share of heat supplied by electricity. The study further identifies the most cost-effective configuration and evaluates its economic attractiveness for industrial consumers seeking to reduce their reliance on natural gas. Finally, a sensitivity analysis of natural-gas prices examines the robustness of the results under the price uncertainty and volatility observed in recent years.

The remainder of this paper is organized as follows. Section 2 reviews the relevant literature. Section 3 describes the methodology used to model and optimize the different system configurations and is largely based on the approach presented in (Hajjaoui, 2026). Section 4 presents, discusses, and interprets the results. Finally, Section 5 summarizes the main findings and outlines directions for future research to support the acceleration of industrial decarbonization.

2. Related Work

2.1. Power-to-heat systems with thermal energy storage

Power-to-heat (P2H) technologies are increasingly discussed as an option for decarbonizing industrial process heat, particularly where renewable electricity can replace fossil fuels in steam and hot-water generation. Available technologies include high-temperature heat pumps, electric boilers, electrode boilers, and resistance heaters, each of which differs in efficiency, temperature range, investment cost, and operational flexibility. Thermal energy storage (TES) can increase this flexibility by decoupling electricity consumption from heat delivery, allowing industrial consumers to shift electricity use to hours with lower prices or higher renewable generation shares (International Renewable Energy Agency IRENA, n.d.; Federal Ministry for Economic Affairs and Energy, 2016; He, et al., 2022).

Molten-salt-based P2H-TES systems are particularly relevant for medium-temperature industrial steam because they combine mature electric heating with sensible-heat storage at temperatures suitable for process heat applications. Trevisan et al. (2022) assessed a molten-salt P2H solution for industrial heat between 150 °C and 450 °C and showed that both component sizing and dispatch strongly affect levelized heat costs. A further experimental study demonstrated the capability of this technology to respond rapidly to dynamic electricity-price signals. However, existing studies often focus on standalone P2H-TES concepts or simplified market assumptions.

Less attention has been paid to the combined effect of hybridization with gas boilers, photovoltaic integration, optimized backup sizing, and industrial grid-fee structures on the economic performance of P2H-TES systems.

2.2. Grid-fee-aware optimization of industrial P2H systems

For industrial consumers, electricity costs are not determined by wholesale market prices alone. In Germany, final electricity costs include energy-related and capacity-related grid fees, taxes, levies, and possible tariff reductions. Capacity-related grid fees are particularly relevant for P2H-TES systems because increasing electric heater power can improve flexibility and enable greater use of low-price electricity, while simultaneously increasing the peak grid demand used for tariff billing. Therefore, economic optimization based only on day-ahead prices may underestimate the cost impact of electrification (Federal Ministry for Economic Affairs and Energy, n.d.).

A specific feature of the German framework is the possibility of individual grid fees for atypical grid usage under Section 19 of the Electricity Network Charges Ordinance (StromNEV). If a consumer can reduce its load during predefined high-load time windows, the capacity-related grid fee may be reduced, although the individual fee must not fall below the regulatory minimum (Bundesnetzagentur, n.d.; Netztransparenz, n.d.). The current regulation applies until 2031 and will subsequently be replaced by a new regulatory framework whose details have not yet been defined (Bundesnetzagentur, 2026). In the absence of reliable information on the future scheme, this study assumes that the current grid-fee discount mechanism remains applicable throughout the analyzed system lifetime. This makes the interaction between system sizing, storage dispatch, PV self-consumption, and grid-fee rules highly relevant. The present study addresses this gap by optimizing multiple P2H-TES configurations for industrial process steam under German tariff conditions, explicitly considering grid-fee discounts, hybrid gas-boiler operation, PV integration, and both technical and economic performance indicators.

3. Methodology

3.1. System configurations

This techno-economic assessment examines a power-to-heat thermal energy storage (P2H-TES) system comprising three main components: an electric heater (EH) with 95 % efficiency, a two-tank molten-salt storage unit with heat losses of 1 % per day, and a steam generator with 98 % efficiency (Trevisan, et al., 2022). Together, these components form the base P2H-TES configuration shown in Fig. 1.

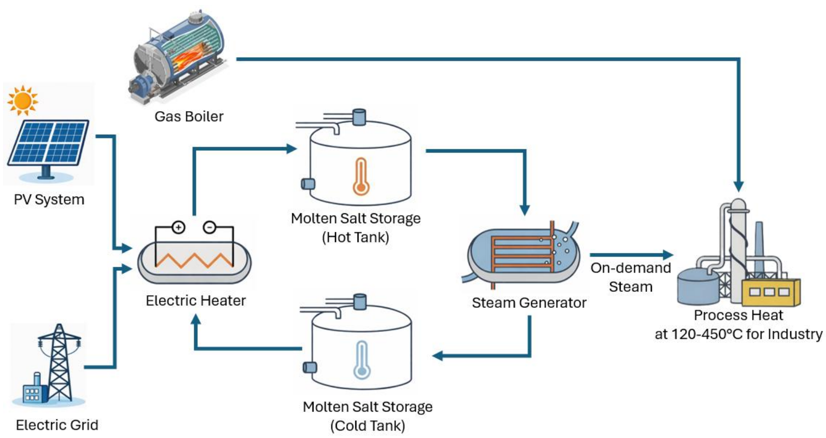

Fig. 1: Schematic of a P2H-TES system hybridized with a gas boiler and a PV system

The P2H-TES system can support the decarbonization of heat supply while potentially reducing electrification costs. During charging, the EH converts electricity into heat, which is stored in the hot tank of the molten-salt storage unit. When heat is required, molten salt is withdrawn from the hot tank and passes through the steam generator, where it transfers heat to generate steam and is consequently cooled before flowing to the cold tank. From there, it is subsequently pumped back to the EH for reheating, thereby completing the cycle.

In some hybrid configurations, the P2H-TES system is supplemented with a natural-gas boiler (GB) with an efficiency of 80 % (Lazenby, et al., 2025). The GB can generate steam directly and may supply part or all of the steam demand, depending on the results of the optimization model developed in this study. In selected configurations, a photovoltaic (PV) system is included to generate electricity on-site, reducing reliance on the electric grid.

In this study, twelve system configurations were modeled and evaluated. They differ based on whether a gas boiler is included (and if so, whether its size is fixed or optimized), whether a PV system is integrated, and whether the model applies a discount on grid capacity fees (Tab. 1).

Tab. 1: System configurations modelled and evaluated

ID	Configuration	Gas Boiler	PV	HLZF Optimization
1	P2H-TES	-	-	-
2	P2H-TES-GBfix	fixed	-	-
3	P2H-TES-GBopt	optimized	-	-
4	P2H-TES-HLZF	-	-	yes
5	P2H-TES-GBfix-HLZF	fixed	-	yes
6	P2H-TES-GBopt-HLZF	optimized	-	yes
7	P2H-TES-PV	-	yes	-
8	P2H-TES-GBfix-PV	fixed	yes	-
9	P2H-TES-GBopt-PV	optimized	yes	-
10	P2H-TES-PV-HLZF	-	yes	yes
11	P2H-TES-GBfix-PV-HLZF	fixed	yes	yes
12	P2H-TES-GBopt-PV-HLZF	optimized	yes	yes

3.2. Optimization and modelling

The optimization model developed in this study consists of two scenarios and twelve different system configurations of the P2H-TES system to investigate which configuration is the most economical compared to the full utilization of a standalone gas boiler. The modelling of all system configurations is based on formulating the required mathematical equations to ensure safe and realistic operation that meets the energy demand while respecting the maximum powers and capacities of the components. The first optimization scenario focuses on identifying the optimal sizes of the electric heater, the thermal storage, and, for some configurations, the gas boiler and PV system. This is achieved by using the LCOH metric (eq. 1) as the objective function to be minimized (Trevisan, et al., 2022). In this study, a 50 % reduction was applied to the component-level capital expenditure (CAPEX) of the standalone P2H-TES system. The second optimization scenario aims only to minimize heating costs, which requires predefined component sizes. This scenario can be applied over different time horizons depending on the availability of forecast and historical data. One advantage of this model is that it takes grid fees into account, which represent a major cost that consumers of electricity or gas must pay based on their consumption. The model was implemented in Python using the Pyomo optimization tool, and the optimization problem is solved with an appropriate numerical solver (GLPK, IPOPT, CBC and MindtPy) depending on the type of problem, which in the studied cases is either a linear programming (LP) problem or a mixed-integer nonlinear programming (MINLP) problem. The optimization model is used to evaluate five different load profiles (Fig. 2), but the detailed analysis in this publication is based on the real load profile obtained from an industrial facility.

$$LCOH = \frac{CAPEX + \sum_{n=1}^{n_{op}} \left(\frac{OPEX_n}{(1 + d_{eco})^n} \right) + \frac{DECOMM_{SYS}}{(1 + d_{eco})^{n_{op}+1}}}{\sum_{n=1}^{n_{op}} \left(\frac{E_{NET}}{(1 + d_{tech})^n} \right)} \qquad \text{(eq. 1)}$$

The modeling was based on historical price data and future price projections developed internally by Fraunhofer ISE (Schöttl, et al., 2026). Historical data included day-ahead electricity prices, average natural gas and CO_2 prices from Energy-Charts (Fraunhofer Institute for Solar Energy Systems ISE, 2026), annual electricity and gas grid fees from Netze BW (Netze BW, n.d.), and electricity consumption taxes and levies applicable to industrial consumers (BDEW Bundesverband der Energie- und Wasserwirtscha, n.d.).

The optimal sizing results for 2032 were used to run annual simulations for the years with available data (2025, 2028, 2032, 2036, 2040, and 2044). Although the economically optimal component sizes may vary from year to year in response to changes in electricity prices and other cost components, the system must be sized for its full operating lifetime. Therefore, 2032 was selected as the representative sizing year, as it reflects future market conditions while remaining sufficiently close to the investment year. Assuming an investment year of 2026 and a system lifetime of 25 years, missing data for the period from 2026 to 2050 were estimated using linear interpolation and extrapolation. The resulting time series were used to calculate the LCOH, annual cash flows, payback period, and electricity share.

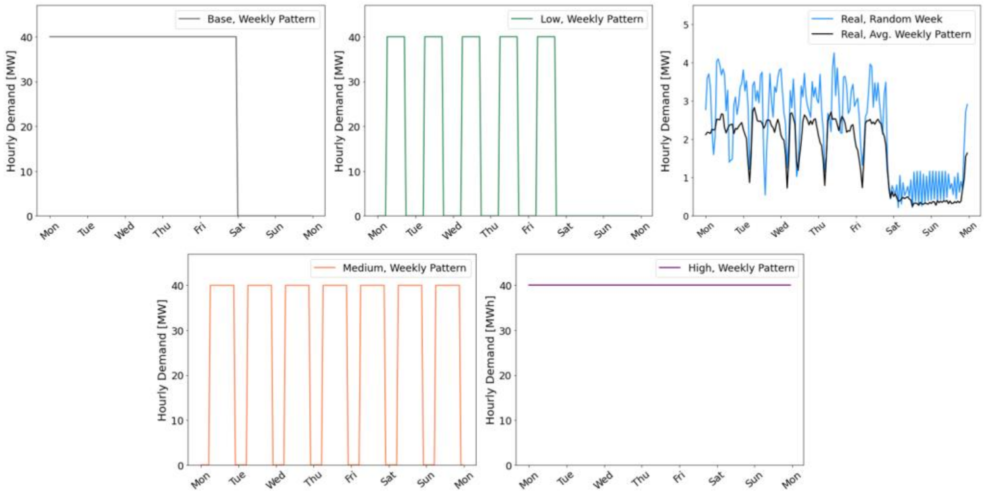

Fig. 2: Studied thermal load profiles

3.3. Hybridization with a gas boiler

P2H-TES systems can be hybridized with a gas boiler, as full electrification is still costly, and hybridization may help ensure the profitability of the proposed system compared to a standalone gas boiler while also achieving environmental benefits. For this purpose, we included a gas boiler as an optional component in the developed model; in other words, the optimizer determines the share of electricity and natural gas in each simulation, such that the outcome is technically feasible and economically optimal. This raises the question of whether the gas boiler should be sized to cover the maximum steam demand of a given industrial application, thereby serving as a full backup, or whether its size should be optimized and potentially undersized, given that there are two other paths to satisfy the heat demand: directly through the electric heater or through thermal storage. Both configurations are investigated in this work, and their impact is analyzed.

3.4. Photovoltaic system integration

Integration of a photovoltaic system into the existing P2H-TES system was implemented to reduce absolute dependence on grid electricity, which still relies heavily on fossil fuels for its generation, and also to avoid paying energy-related electricity grid fees, taxes and levies. This system allows the use of freely available solar energy, which is converted into electricity and subsequently into heat. Nevertheless, a utility-scale PV system requires CAPEX of 700 EUR/kWp and fixed operating expenditure (OPEX) of 13.3 EUR/kW per year (Kost, et al., July 2024). In this study, no discount was applied to the PV CAPEX. The simulated PV system is assumed to be located in Freiburg, Germany (latitude 47.996°, longitude 7.849°, elevation 282 m).

In the component sizing scenario, the integration of a PV system allows electricity to be supplied from either the electric grid or the PV system. Consequently, the total electric power supplied equals the sum of grid-to-heater and PV-to-heater power, introducing two new decision variables to the optimization model (eq. 2). Because the electric heater is no longer solely reliant on the grid, its size is not assumed to equal the annual peak grid power. Instead, the heater size and the peak grid power are separated into independent decision variables, as shown in eq. 3. Furthermore, this PV integration requires slight modifications to the electric grid fee constraints, which must now be calculated based exclusively on the power drawn from the grid.

$$P_{EH,t} = P_{grid\_to\_heater,t} + P_{pv\_to\_heater,t} \qquad \text{(eq. 2)}$$

$$P_{grid,peak} \geq P_{grid\_to\_heater,t} \quad \text{(eq. 3)}$$

Finally, to estimate the PV system output for the selected location, pvlib was used to calculate the hourly capacity factor, $CF_{PV,t}$ (defined as hourly AC output divided by DC rated capacity). This factor was derived from a pvlib simulation of an arbitrarily sized PV system, utilizing specific module types, inverter types, and cell temperature models from the pvlib database (Anderson, et al., 2023), combined with radiation data from PVGIS. The PV module's tilt angle (36°) and azimuth (177°, south-facing) were optimized using PVGIS to achieve maximum energy output (Suri, et al., 2008).

In this work, it is not assumed that the entire useful PV output must be directed exclusively to the electric heater. Forcing full utilization of PV power can negatively affect the optimization objective and may violate physical constraints, particularly in real-world scenarios involving negative electricity prices and system capacity limits. Therefore, the numerical solver determines how much PV power is used directly by the system and when curtailment should occur, as formulated in eq. 4. Unused PV power results from both these physical limitations and the pursuit of optimal operating conditions. Furthermore, since the facility requires electricity for other operational needs, any PV power not utilized by the power-to-heat system can be redirected to these other purposes rather than being wasted.

$$P_{pv\_to\_heater,t} \leq CF_{PV,t} \cdot P_{PV,max} \quad \text{(eq. 4)}$$

3.5. Discount on electricity grid fees

With atypical grid usage, discounts of up to 80 % on capacity grid fees can be obtained by meeting certain requirements. These require reducing the maximum possible electrical power consumption by at least 100 kW during specific hours and months. The discount percentage depends on how much peak power is reduced during high-demand time windows, known in German as Hochlastzeitfenster (HLZF). The distribution system operators (DSOs) forecast and publish these time windows for their respective locations. Securing a discount on the capacity grid fee was modeled mathematically by adding two main constraints (eqs. 5 and 6) to the optimization model used to size the electric heater, along with a slight modification of the objective function. For the one-year simulations, the capacity grid fee was calculated based on P_{HLZF}, rather than $P_{EH,max}$ or P_{peak}.

$$P_{HLZF} \geq 0.2 \cdot P_{EH,max} \quad \text{(eq. 5)}$$

$$P_{HLZF} \geq P_{EH,t}, \forall t \in \tau_{HLZF} \quad \text{(eq. 6)}$$

3.6. Gas price variation

This study also examines the impact of natural gas price variations on the KPIs and the electricity share. No new component sizing was performed; instead, the 2032 sizing results for the P2H-TES system hybridized with a gas boiler were used, without considering grid fee discounts or the PV system. The gas boiler size was set to the default value for each case, accounting for an assumed boiler efficiency of 80 %.

The electric heater (4.10 MW) and storage capacity (20.72 MWh) were fixed based on optimal sizing results from 2032 for a hybrid system with a 5.66 MW gas boiler for the real load profile considered here. Natural gas prices varied across five scenarios: −25 %, 0 %, +25 %, +50 %, and +75 %. Energy-related gas grid fees were held constant throughout the analysis, despite varying gas consumption. However, this applied only to simulations using future price projections; grid fees were optimized for simulations based on historical prices. This simplification was necessary because available future price projections lack sufficient detail to adjust fees accurately across consumption ranges (e.g., Netze BW, the biggest distribution grid operator in Baden-Württemberg, differentiates eight tariff ranges: AP1-AP8).

4. Results and discussion

4.1. Component sizing

Different system configurations result in varying sizes for the electric heater, thermal storage, and, where applicable, gas boiler and PV system (Fig. 3). It was expected that optimizing under the atypical grid-use scheme with HLZF would favor larger electric-heater capacities. As long as the additional electricity demand is shifted outside the predefined high-load time windows, it does not increase the billed capacity charge. The results confirm this expectation: the HLZF-based grid-fee discount increases the optimal electric-heater size across all system configurations.

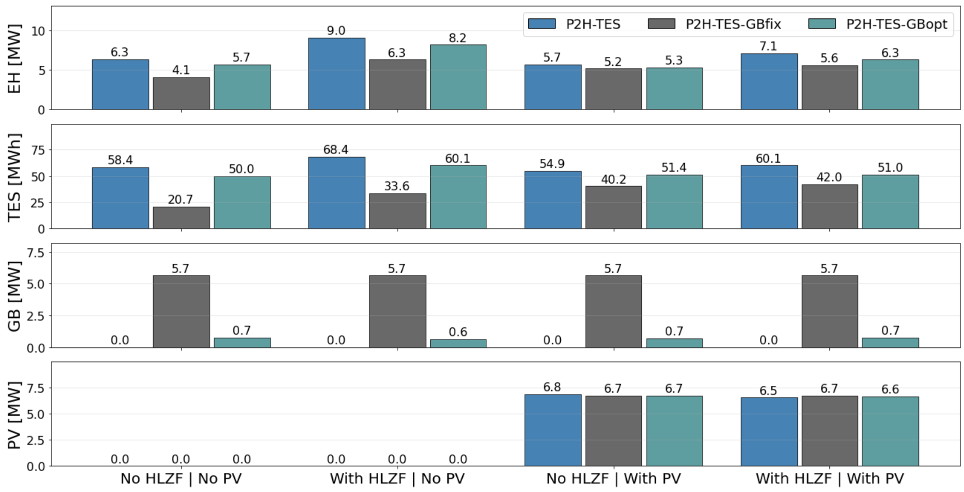

Fig. 3: Component sizing by system configuration, real load profile, 2026-2050

The optimal TES capacity is consistently higher in fully electrified P2H-TES configurations than in hybrid configurations with a gas boiler, reflecting the greater need for load shifting and heat-supply flexibility in the absence of gas backup. Where the gas boiler capacity is optimized, it decreases from 5.7 MW in a fully redundant system to as low as 0.6 MW. Under the assumed future electricity, natural gas, and CO_2 price trajectories, this indicates that electrification is economically preferred, while a small gas boiler remains economically optimal as a supplementary heat source. This is particularly relevant for the real load profile, which exhibits fluctuating demand and includes periods, especially during weekends, when the heat demand falls below 0.6 MW and can be met by a comparatively small gas boiler. Across the PV-integrated configurations, the optimal PV capacity averages 1.15 MW per MW of electric-heater capacity. This indicates that on-site PV generation affects the optimal sizing of both the electric heater and the thermal storage system. The resulting PV capacity exceeds the electric-heater capacity, rather than being sized to match it directly. This slight oversizing may compensate for PV derating effects, such as off-peak solar irradiance, inverter and temperature losses.

4.2. Performance of various system configurations

The twelve system configurations were assessed from an economic and environmental perspective by calculating the LCOH, annual cash flows, payback period, and the share of electricity in the energy mix. Fig. 4 shows that the LCOH varies considerably across configurations, with a minimum of 68.0 EUR/MWh achieved by the hybrid configuration combining an optimally sized gas boiler, a PV system, and discounted grid fees. Moreover, all optimized configurations achieved an LCOH below the 97.9 EUR/MWh of the standalone gas boiler. This indicates that partial or full electrification can be a worthwhile investment for industries requiring process heat.

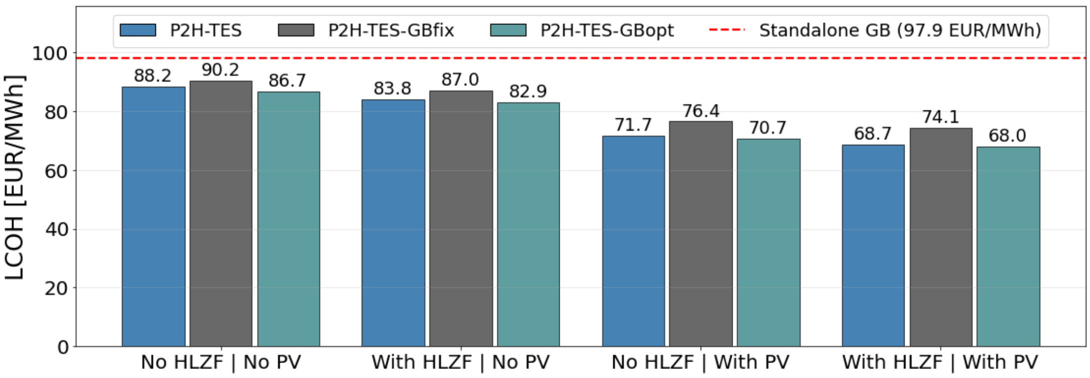

Fig. 4: LCOH by system configuration, real load profile, 2026-2050

Based on current and projected future prices, the proposed system configurations are profitable over their full lifetime, although the annual savings in the first years are not sufficient to recover the high initial investment. Fig. 5 shows the cumulative cash flows over the systems' lifetime, with CAPEX deducted in the first year. Depending on the configuration, the cumulative cash flows turn positive in different years, once the accumulated savings exceed the initial investment. This is reflected in the payback period (Fig. 6), which ranges from 8.0 (P2H-TES-GBopt-PV-HLZF) to 10.7 (P2H-TES) years. Notably, the fully electrified P2H-TES-PV-HLZF configuration reaches investment recovery after 8.3 years, only 0.3 years above the lower end of this range. This suggests that eliminating natural gas from the energy mix can remain economically attractive under the considered scenarios.

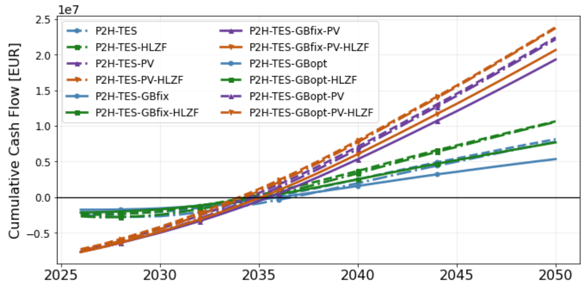

Fig. 5: Cumulative cash flows, real load profile, 2026-2050

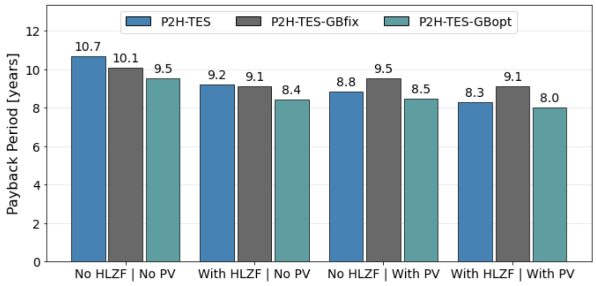

Fig. 6: Payback period, real load profile, 2026-2050

For the hybrid system configurations with a gas boiler, the electricity share in final energy consumption was evaluated both annually and as an average over the system's lifetime. Fig. 7 shows that, as a general pattern, the electricity share is expected to increase gradually before decreasing slightly in later years. This decline results from the assumed energy-price trajectory, which conservatively reflects potentially substantial increases in electricity prices during the final steps towards climate neutrality by 2045. However, because investments occur upfront and the modeled payback periods range from 8.0 to 10.7 years, uncertainty in energy prices in these later years has limited relevance for the investment decision. The lowest share, approximately 53.4 %, occurs for the configuration without a PV system and without grid fee discounts, whereas the highest share, 89.8 %, is achieved by the hybrid configuration combining an optimally sized gas boiler, a PV system, and a capacity grid fee discount.

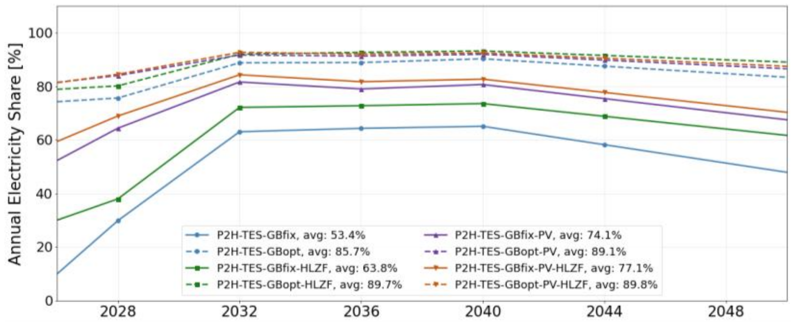

Fig. 7: Electricity share of hybrid system configurations, real load profile, 2026-2050

It is worth noting that these results depend on the selected component sizes and therefore represent one of several possible outcomes, particularly during the first years of the investment period, when natural gas can still be the more economical option. When the component sizing is optimized for each year individually, the P2H-TES components may be omitted entirely in favor of a gas boiler, an effect that is most pronounced in the simulations for 2023, 2024, and 2025 (Hajjaoui, 2026). Since the investment is nevertheless recovered within approximately 11 years at the upper limit, this observation has limited influence on the overall economic attractiveness of the proposed configurations. Still, it provides a valuable insight for industrial users, as they should anticipate that the first years of operation may yield no savings at all relative to a standalone gas boiler, while requiring a considerably higher upfront investment. Being aware of this early-stage pattern allows for realistic expectations and supports well-informed investment planning over the full system lifetime.

4.3. Impact of varying gas prices

The main finding of a sensitivity analysis regarding the gas price is that a higher gas price directly leads to a higher LCOH, and a greater share of electricity for the hybrid system (Fig. 8). These results therefore provide a strong incentive for industrial consumers to electrify their heat generation, offering an effective safeguard against supply shortages and price spikes in the gas market.

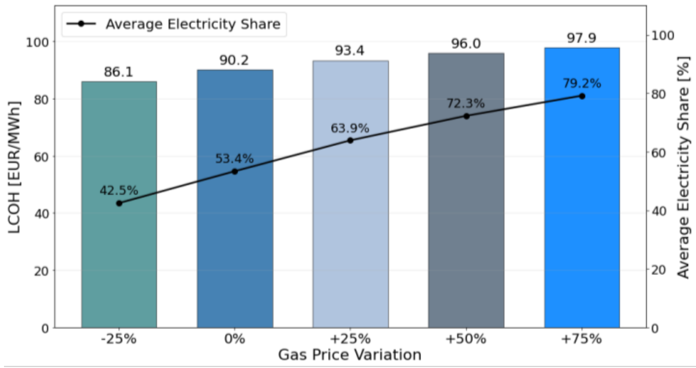

Fig. 8: LCOH and average electricity share, P2H-TES-GBfix, real load profile, 2026-2050

4.4. Comparison of load profiles

While the previous results were based on the real measured industrial load profile, this section examines the sensitivity of the results by comparing four standardized profiles: base, low, medium, and high. For each load profile and each system configuration, the sizes of the electric heater, thermal energy storage, gas boiler, and PV system were optimized separately for 2032 and then used in the analysis of this section.

Fig. 9 illustrates that higher CAPEX generally leads to a higher net present value (NPV), and this applies particularly to system configurations with a PV system, which significantly increases the initial investment required. This also raises the question of whether an industrial user of P2H systems is capable of financing the high amount of money required to achieve a high positive NPV. The figure also shows that the P2H-TES configuration results in a negative NPV under the high load profile. The reason is that full electrification is costly, while this load profile offers hardly any demand-side flexibility, as heat is required 24/7. Under these conditions, thermal storage can barely be exploited to shift demand, and its economic value remains low. Since no reduction in the capacity-based grid fee is granted in this configuration, there is also no incentive to install larger electric heater and TES capacities that would allow flexible, price-driven operation, so the flexibility potential of the system stays untapped. In contrast, the P2H-TES-HLZF configuration reaches a positive NPV even under the high load profile. This underlines the decisive role of grid fee reductions in making the electrification of industrial heat supply economically attractive.

Fig. 9 further shows that a lower LCOH is generally associated with a higher electricity share across multiple system configurations. Furthermore, the analysis using the base, low, medium, and high load profiles demonstrated the potential to achieve an LCOH of less than 68.0 EUR/MWh, which is, in some cases, a lower minimum LCOH than what was achieved with the real load profile.

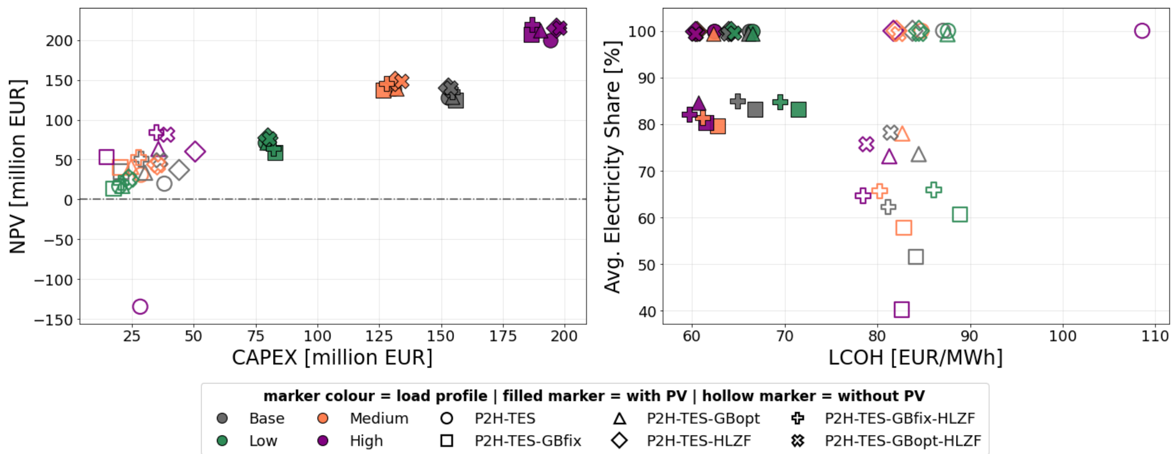

Fig. 9: NPV, CAPEX, average electricity share, and LCOH for base, low, medium and high load profiles, 2026-2050

What is particularly interesting is that all system configurations that include a PV system achieve a lower LCOH than the configurations without one. This indicates that on-site electricity generation from solar energy is economically beneficial, especially in the German context, where electricity prices are high once all components of the final electricity bill are taken into account.

In general, an integrated PV system plays an important role in raising the electricity share without adversely affecting the economic indicators compared with configurations without PV. This effect is most pronounced in the configurations that combine an integrated PV system with an optimized gas boiler size, which reach an electricity share of nearly 100 %. The reason is that the optimized gas boiler capacity was approximately 0.75 MW for all load profiles analyzed, which is very small compared to the assumed thermal demand of 40 MW. Since the optimization sizes all components purely mathematically to minimize the LCOH, this outcome indicates that full electrification is already profitable in these cases and that a gas boiler is essentially not required. This is further supported by the fact that the LCOH of these configurations differs only marginally from that of the corresponding configurations without a gas boiler.

Overall, varying the load profile changes the results significantly, meaning each industrial load profile should be assessed individually. However, since five load profiles were tested, some general conclusions can be drawn, particularly regarding the importance of the PV system in supporting cost-effective and environmentally friendly electrification.

5. Conclusions

P2H-TES systems with different combinations of gas-boiler integration, PV integration, and grid-fee-aware operation offer a promising pathway for the partial or full electrification of industrial heat generation. Under the assumptions considered in this study, all optimized P2H-TES configurations achieve lower levelized costs of heat than the standalone gas-boiler reference. The most cost-effective configuration combines an optimally sized gas boiler, PV integration, and a discount on capacity-based grid fees, achieving an LCOH of 68.0 EUR/MWh, compared with 97.9 EUR/MWh for the standalone gas boiler. The calculated payback periods of 8.0-10.7 years further indicate that electrification can be economically attractive despite high upfront investment costs.

The results also show that system design should be adapted to the specific industrial load profile. PV integration and grid-fee-aware operation substantially affect the optimal sizing of the electric heater, thermal storage, and gas boiler. In hybrid configurations with a gas boiler, the share of electricity in final energy consumption reaches up to 89.8 % for the real load profile, showing that industrial consumers can substantially reduce their dependence on natural gas while maintaining operational flexibility. The gas-price sensitivity analysis indicates that hybrid P2H-TES systems can partly mitigate the impact of rising gas prices by shifting heat generation toward electricity.

Nevertheless, the findings depend on assumptions regarding future electricity, natural-gas, and CO_2 prices as well as grid-fee developments, and should therefore be interpreted with caution. In particular, future regulatory changes to the design of grid fees and the transferability of the results to other industrial sites require further investigation. Future work should therefore assess additional locations, load profiles, and regulatory settings and could extend the optimization framework to include battery storage or other flexibility options.

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Appendix: UNITS AND SYMBOLS

Table 1: List of symbols

Symbol	Description	Unit
$\boldsymbol{n_{op}}$	Operational lifetime	Years
$\boldsymbol{n}$	Year index, $n \in \{1,2,\dots,n_{op}\}$	-
$\boldsymbol{d_{eco}}$	Economic discount rate	%
$\boldsymbol{d_{tech}}$	Technology degradation rate	%
$\boldsymbol{E_{NET}}$	Annual net thermal energy demand	MWh
$\boldsymbol{DECOMM_{SYS}}$	Decommissioning costs	EUR
$\boldsymbol{P_{EH,t}}$	Power of the electric heater at each timestep	MW
$\boldsymbol{P_{grid\_to\_heater,t}}$	Electric power drawn from the grid by the electric heater at each timestep	MW
$\boldsymbol{P_{pv\_to\_heater,t}}$	Electric power supplied by the PV system to the electric heater at each timestep	MW
$\boldsymbol{P_{grid,peak}}$	Annual peak electric power drawn from the grid	MW
$\boldsymbol{CF_{PV,t}}$	Capacity factor of the PV system at each timestep	-
$\boldsymbol{P_{PV,max}}$	Maximum capacity of the PV system	MW
$\boldsymbol{P_{HLZF}}$	Annual maximum electric power drawn from the grid by the system during HLZF time windows	MW
$\boldsymbol{P_{EH,max}}$	Nominal power of electric heater	MW
$\boldsymbol{\tau_{HLZF}}$	Set of timesteps for the HLZF period	Hourly date-time stamp