Power-to-Heat-to-Power (P2H2P) A Scenario Analysis

Techno-economic performance of Power-to-Heat-to-Power systems under real electricity and district heating market conditions

Master's thesis in Master Programme Sustainable Energy Systems

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DEPARTMENT OF SPACE EARTH AND ENVIRONMENT

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Abstract

Power-to-Heat-to-Power (P2H2P) systems have emerged as a flexible energy storage solution for power systems with increasing shares of variable renewable energy (VRE) generation. This thesis investigates the economic performance of a representative P2H2P configuration under Swedish electricity and district heating market conditions. A techno-economic modeling framework was developed to evaluate system profitability under varying market conditions, operational strategies, taxation policies, and storage scales. The reference configuration was based on combined heat-and-power (CHP) operation supplying both electricity and heat.

The results demonstrate that taxation has a major impact on system viability. Under the current Swedish electricity consumption tax regime, P2H2P systems exhibit weak economic performance. While increased electricity market volatility, higher avoided district heating production cost and electricity-only-focused operation improved profitability, the improvements were generally marginal. However, the possibility of exploiting intra-hour price variations has the potential to substantially improve profitability. The optimal storage scale was found to depend on electricity market dynamics, operational strategy, and dynamic flexibility.

In addition, the results suggest that the higher economic value of electricity relative to district heat outweighs the benefits of combined heat and power delivery. Electricity-only operation also reduces overall system complexity and improves dynamic flexibility. This aligns with the current development direction of Pumped Thermal Energy Storage (PTES), the leading P2H2P configuration, which is primarily designed for electricity-to-electricity applications. The results therefore indicate that future P2H2P systems may benefit from focusing primarily on electricity market participation rather than CHP-like operation.

Keywords: Power-to-Heat-to-Power, thermal energy storage, district heating, electricity market arbitrage, techno-economic analysis, pumped thermal energy storage, variable renewable energy, economic performance, operational strategy.

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Linus Persson and Alve Sonnerup, Gothenburg, June 2026

List of Acronyms

Below is the list of acronyms that have been used throughout this thesis listed in alphabetical order:

AEY	Annual Energy Yield
BESS	Battery Energy Storage System
CAES	Compressed Air Energy Storage
CAPEX	Capital Expenditures
CHP	Combined Heat and Power
CRF	Capital Recovery Factor
CSP	Concentrated Solar Power
DER	Distributed Energy Resource
DH	District Heating
GE	Göteborg Energi
HX	Heat Exchanger
KPI	Key Performance Indicator
LCOS	Levelized Cost Of Storage
LCOE	Levelized Cost Of Electricity
LHS	Latent Heat Storage
ORC	Organic Rankine Cycle
OPEX	Operational Expenditures
PBP	Payback Period
PI	Profitability Indicator
PTES	Pumped Thermal Energy Storage
P2H2P	Power To Heat To Power
PV	Photovoltaic
RES	Renewable-based Energy Sources
RTE	Round-trip Efficiency
SHS	Sensible Heat Storage
sCO2	Supercritical CO2
TCES	Thermochemical Energy Storage
TES	Thermal Energy Storage
VRE	Variable Renewable Energy

Nomenclature

Below is the nomenclature of indices, sets, parameters, and variables used throughout this thesis.

Indices

i	Index for heat production unit
t	Time-step index

Sets

I	Set of district heating production units
T	Set of time steps within the simulation horizon

Parameters

c_{cyc}	Cycling penalty cost [SEK/MWh]
$c_{i,t}$	Variable production cost of heat production unit i at time t [SEK/MWh]
c_{tax}	Electricity consumption tax [SEK/MWh]
$CAPEX$	Total capital expenditure [SEK]
$CAPEX_{ann}$	Annualized capital expenditure [SEK/year]
C_{TES}	Specific thermal energy storage cost [EUR/MWh]
CRF	Capital recovery factor [-]
Δt	Time-step duration [h]
δ	Daily thermal loss factor [-]
D_t	District heating demand at time t [MW]
E_{TES}^{max}	Maximum TES storage capacity [MWh$_{th}$]

η_{elec}	Electrical round-trip efficiency [-]
η_{heat}	Heat recovery efficiency [-]
η_{HX}	Heat exchanger efficiency [-]
γ	Hourly TES retention factor [-]
λ_t	Electricity spot price at time t [SEK/MWh]
N_{cycles}	Maximum number of storage cycles [-]
P_{in}^{max}	Maximum charging power [MW_{el}]
P_{out}^{max}	Maximum thermal discharge power [MW_{th}]
q_i^{max}	Maximum heat production capacity of unit i [MW]
r	Real discount rate [-]

Variables

C_{sys}	Total annual district heating system cost without P2H2P [SEK]
C_{sys}^{P2H2P}	Total annual district heating system cost with P2H2P [SEK]
$E_{TES,t}$	Thermal energy stored in TES at time t [MWh_{th}]
$P_{in,t}$	Electrical charging power at time t [MW_{el}]
$P_{out,th,t}$	Thermal discharge power from TES at time t [MW_{th}]
$q_{i,t}$	Heat production from unit i at time t [MW]
$Q_{heat,out}$	Useful heat delivered to district heating [MWh_{th}]
V_{P2H2P}	Annual value of the P2H2P system [SEK/year]

Contents

List of Figures

List of Tables

1
Introduction

The electricity consumption in Sweden in 2025 was around 135 TWh [1, 2]. According to the Swedish Energy Agency, electricity demand is projected to increase to between 220 TWh and 360 TWh by 2050 [3]. This substantial increase is largely driven by industrial electrification, including fossil-free steel production, hydrogen production, and other energy-intensive industrial processes. Electrification of the transport sector and increasing digitalization are also expected to contribute to the projected growth in demand. The growing demand for electricity in Sweden is expected to be met primarily by wind power [3].

With a large share of wind power in the electricity system, the power system will likely experience an increase in both the duration and frequency of temporary shortages and surpluses. These temporal mismatches between electricity generation and demand create a growing need for power system balancing.

Power-to-heat-to-power (P2H2P) with high-temperature thermal energy storage (TES) could provide a solution to mitigate fluctuations in electricity production, enabling a more efficient match between supply and demand [4]. Additionally thermal energy storage systems are already widely used in district heating networks, where they provide operational flexibility by decoupling heat production from heat demand [5].

In contrast to P2H2P systems, electrochemical storage systems such as lithium-ion batteries offer high electrical efficiency, reaching 95 %, and high energy density making them suitable for frequency regulation and intraday balancing. However, material constraints and cost limitations make them less economically viable for long-duration storage. Mechanical storage technologies such as pumped hydro storage and compressed air energy storage (CAES) can provide large-scale storage for intermediate to long durations but are constrained by geographic and siting requirements [6]. Chemical storage systems like hydrogen are energy dense and thus offer large storage potential, making them suitable for long-duration and seasonal balancing. Hydrogen is also expected to play an important role in the decarbonization of energy-intensive industries, including fossil-free steel production and hydrogen-based fuels. Although hydrogen storage systems are generally unsuitable for short-term grid services due to low round-trip efficiency, conversion losses, and comparatively slow response times [7].

Thermal energy storage configurations fill the role of intermediate duration (day-scale) storage without being geographically bounded, complementing the other energy storage technologies [7]. While previous research has evaluated and optimized various P2H2P configurations, these studies often fail to capture how system performance is influenced by the surrounding energy system. The operation and viability of P2H2P units depend strongly on the structure of the electricity and heating systems in which they are integrated. This study therefore employs scenarios based on empirically grounded representations of the SE3 electricity market and the Gothenburg district heating system, while systematically varying market conditions and operational strategies.

1.1 Aim

The aim of this master's thesis is to analyze how P2H2P systems perform within real-world coupled power and district heating systems, and how their value depends on market conditions and operational strategies.

1.2 Scope

To address the aim of this study, the following research questions were formulated:

1.) Scenario-Based System Performance - *How does the economic performance of a representative P2H2P system vary under different external system conditions?*

- What is the impact of the Swedish electricity consumption tax on system profitability when comparing current taxation levels to a no-tax scenario?
- How does system performance vary across electricity price regimes with different levels of volatility, based on historical price data from 2023, 2024, and 2025 in the SE3 electricity market?
- How is system performance affected by different district heating systems, such as biofuel-based or excess heat–dominated systems?

2.) Operational Sensitivity - *How sensitive is a representative P2H2P system's performance to operational parameters?*

- Does P2H2P performance change with scale of the energy-to-power ratio (i.e., storage duration, MWh/MW)?
- How does the choice of operational strategy influence system value:
  - Operation as a combined heat and power (CHP-like) system delivering both heat and electricity?
  - Operation focused solely on electricity market participation (power-only mode)?

1.3 Limitations

While this study provides a comprehensive analysis and feasibility study of P2H2P, its scope is defined by several methodological and technical boundaries. The following limitations are established to maintain analytical focus and account for the inherent assumptions within the multi-disciplinary framework.

Future Spot-Prices and Market Dynamics
A primary limitation is the decision to exclude the simulation of long-term future spot-price scenarios. Due to the inherent stochasticity of energy markets, driven by non-linear variables such as geopolitical shifts and evolving carbon taxation, a quantitative price forecasting over a multi-decadal horizon carries an unacceptable margin of error. To maintain a feasible focus on technological performance rather than advanced econometric forecasting, this study relies on a three-year historical baseline (2023–2025) for the electricity market and 2024 consumption data for the district heating system in Gothenburg.

Geographical Boundary
The quantitative modeling is localized to the district heating system in the Gothenburg region using the electricity bidding zone SE3 for electricity price data. While the broader implications for the Swedish national grid are discussed qualitatively, the technical simulations are region-specific. This constraint is necessary as a comprehensive national modeling of P2H2P dynamics would constitute a separate study in its own right.

Revenue and Market Participation
The economic model is restricted to day-ahead arbitrage and reduced district heating production cost within the Gothenburg DH-network. Other potential revenue streams such as the ancillary services FCR and mFRR "nätnytta" (network benefits), and "mothandel" (counter-trading) are excluded from the quantitative analysis. While these services represent significant future opportunities for P2H2P assets, their inclusion would introduce layers of econometric complexity and price uncertainty that fall outside the current scope.

Thermal Management and Infrastructure
A specific boundary has been set regarding the cooling requirements during the summer months when DH demand in Gothenburg is at its seasonal minimum. The local DH network already processes significant inflexible waste-heat baseloads from industrial producers such as ST1, Preem, and Renova, which is often greater than summer demand. Thus, this study assumes the existing DH infrastructure with coolers and accumulators absorbs the excess heat generated from P2H2P. As a consequence the CAPEX for dedicated on-site cooling systems is excluded from the economic model. This simplification allows for a more generalized evaluation of the P2H2P plant's core profitability.

Simplification assumptions
The model assumes the cost of P2H2P pipeline infrastructure to be negligible because the site is assumed to be chosen adjacent to the existing DH pipeline system.

Socio-political limitations
This thesis focuses on providing a theoretical background and scenario-based analysis of a technology that has not yet reached commercial maturity, where social and political aspects of the development are not considered.

1.4 Thesis outline

This thesis is structured into six primary chapters, guiding the reader from the theoretical foundations of energy markets to the techno-economic evaluation of the proposed storage system. Following this introductory chapter, **Chapter 2: Theory** provides the necessary technical and market background. It covers the dynamics of district heating and the Swedish electricity markets, the impact of Variable Renewable Energy (VRE), and the fundamental physics of Power-to-Heat-to-Power (P2H2P) systems. **Chapter 3: Methodology** details the modeling framework and scenario design, defining the simulation logic, the mathematical approach to measuring price volatility, and the economic KPIs used for evaluation.

The findings of the study are presented in **Chapter 4: Results**, which includes KPIs related to the reference years 2023-2025, the influence of taxation policies, the removal of excess heat, and the impact of temporal price resolution on profitability. In **Chapter 5: Scenario Analysis**, the results are processed, plotted to show trends and interpreted. These results are further examined in **Chapter 6: Discussion**, which synthesizes the data to evaluate the integrated viability of P2H2P while reflecting on revenue drivers and storage scaling. Finally, **Chapter 7: Conclusions** summarizes the key findings of the research. **Chapter 8** and provides recommendations for **Future work** based on the identified research gaps.

1.5 AI disclosure

Artificial intelligence (AI) tools such as ChatGPT and Gemini were used solely for linguistic assistance, formatting support, table and figure presentation, minor coding support, and text refinement. All modeling, simulations, analysis, interpretation of results, and conclusions were independently developed by the authors.

2
Theory

2.1 District heating, (DH)

District heating consists of one or several centralized heat generating plants connected with their consumers through a network of pipelines. Their main purpose is to provide heat in a cost efficient and effective way. The solution is flexible and, in Sweden, generally utilizes fuels with low carbon footprint or waste heat. In the worlds largest markets such as China and Russia vast parts of the heat is still produced with fossil fuels and thus there is a large potential for de-carbonization [8]. In the case of Gothenburg 90% of the apartment buildings are connected to the 1230 km long pipeline system. Up to 70% of the heat in the system comes from recovered heat, primarily from refineries and waste combustion [9]. This high share of recovered energy results in a relatively low environmental impact and specific emissions are often lower than individual heating alternatives [11].

2.1.1 District heating market

The district heating market in Gothenburg is a natural monopoly where Göteborg Energi (GE) owns and runs the entire DH network. The DH market is for the end customer not spot-price based but rather based on fixed seasonal prices. Rather than following spot-price fluctuations, trade is governed by the "Swedish District Heating Act" [12], prioritizing stability through a locally regulated model. Transparency is maintained via the 'Price Dialogue' framework [13] rather than open competition. This structure results in seasonal tariffs for end-customers (detailed in Table 2.1 for 2026), which are designed to mirror GE's varying production costs throughout the year.

Period / type	**Price**
June – August	13 öre/kWh
May & September	36 öre/kWh
October – April	94 öre/kWh
Fixed fees	
Gridfee	374 kr/month
Rent (District heating central)	345 kr/month

Table 2.1: District heating prices 2026 inc. VAT [10].

GE buys heat from different sources through long term agreements. The heat producers are activated through merit-order effect where spill heat is prioritized as base-load [14]. GE buys spill heat based on a "avoided cost" with "profit sharing" model [15]. When spill heat is not enough GE uses its large-scale heat-pump recovering heat from Gryaab´s wastewater treatment plant [16] or starts a CHP, depending on electricity price. At higher demand events, plants burning pellets, oil and natural gas are utilized [17]. Because of the large penetration of spill-heat in Gothenburg DH-network the prices tend to remain relatively low in comparison to other DH-networks around Sweden, see Figure 2.3 for visualization.

2.1.2 Fuel- & corresponding DH-prices

In Gothenburg, the peak and mid loads plants normally burn biofuels or gas. Both of these fuels have in recent years seen sharp increases in their prices. Biofuel prices has surged in Sweden as can be seen in Figure 2.1, in part driven by supply chain disruptions and the discontinuation of wood product imports from Russia [19]. At the outbreak of the Russo-Ukranian war the gas prices more than doubled in Sweden as can be seen in Figure 2.2. Since then the gas prices has been on a steady decline, yet are significantly higher than prior to the outbreak of the war. Consequently district heating customers has experienced an increase in prices as can be seen in Figure 2.3, [21]. These sharp increases in prices makes DH less competitive in comparison to other heating alternatives. Heat pumps or ground-source heating systems are more sensitive to electricity prices rather than fuel commodities.

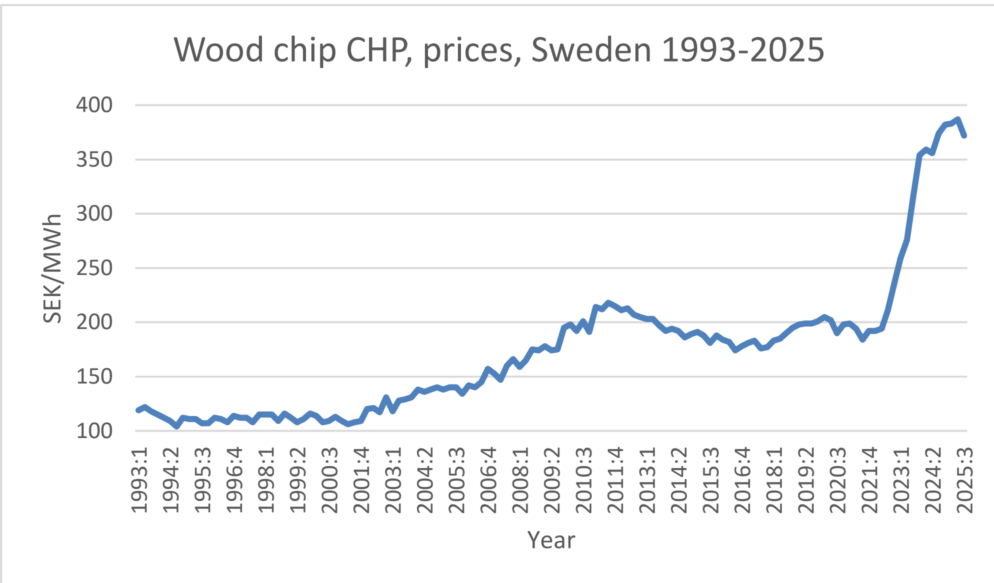

Figure 2.1: Wood chip prices for CHP, Sweden 1993-2025. Source: [18].

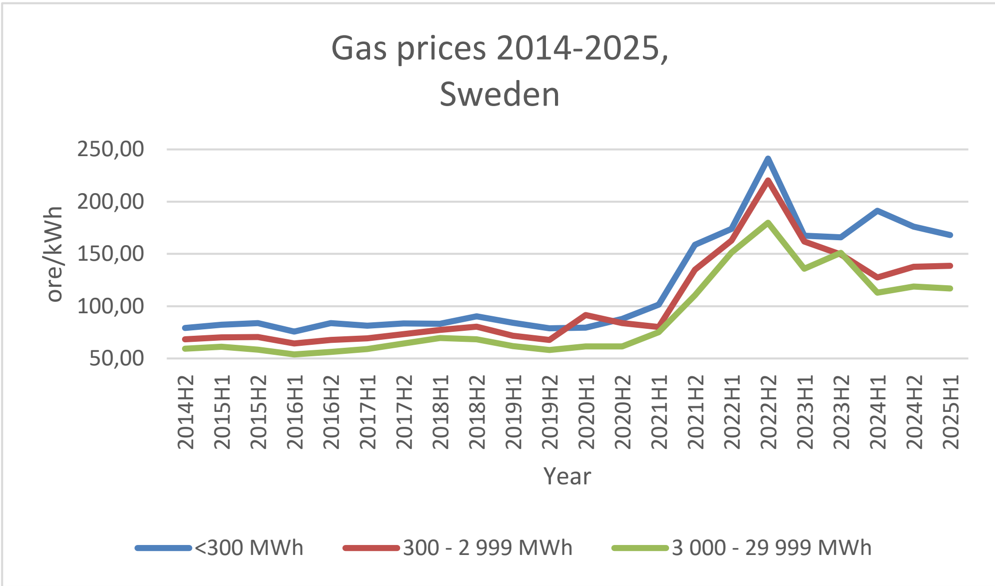

Figure 2.2: Non-residential gas prices Sweden 2014-2025. Prices include transmission and tax. Source: [20].

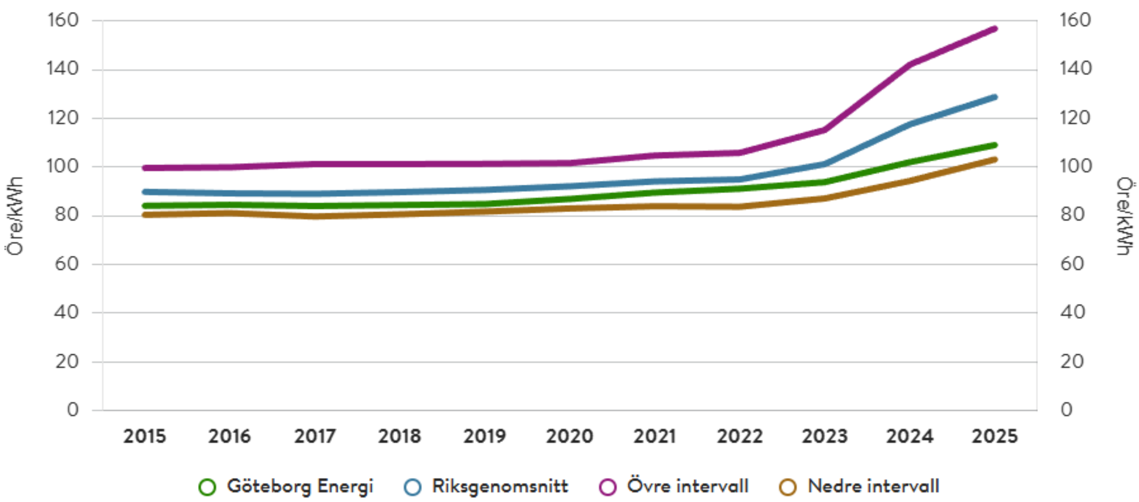

Figure 2.3: DH prices, Sweden & Gothenburg 2015-2025. Source: [10].

2.2 Electricity market

The electricity market serves as the commercial framework for maintaining the continuous physical balance between generation and consumption. Unlike other commodity markets, electricity is economically unique due to its limited large-scale storability and the requirement for instantaneous delivery [22]. As the energy system transitions toward a higher share of Variable Renewable Energy (VRE), as described in the introduction, the market dynamics shift from being fuel-price driven to being increasingly dependent on weather conditions and grid flexibility. With a large share of VRE, the power system will likely experience an increase in both the duration and frequency of temporary shortages and surpluses. These discrepancies in time between production and demand create a need for power system balancing [23].

For a P2H2P system, the electricity market is not merely a trading platform but the primary driver of operational logic. The system acts as a price smoother that exploits price volatility to bridge the temporal gap between electricity surplus and deficit. The market is structured into different time frames to manage everything from long-term planning to real-time balancing. The following sections detail the specific mechanisms of the Swedish bidding zones and the various trading platforms relevant for storage operations [22].

2.2.1 Day-ahead market

The day-ahead market, also called spot-market is the market where a majority of the electricity is traded. The market determines quarter-hour prices for the day ahead through auctions. Producers and retailers are able to submit bids for their production respectively consumption. The price is then determined through a marginal pricing model as shown in Figure 2.4. The spot price can be described as the price to produce the last MWh sold in the market to be able to match the demand. At noon each day the price for the day ahead is determined, every supplier and retailer knows how much they will produce and consume respectively. This auction occurs independently of how the electricity is produced, meaning every producer participates. All European electricity markets operate as an interconnected system governed by a common European auction [31].

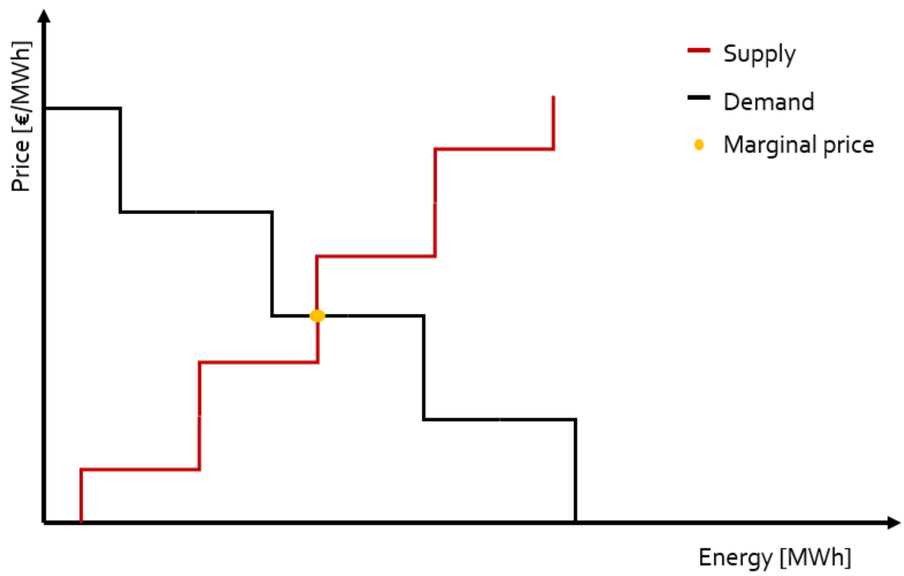

Figure 2.4: Marginal price simple electricity market

When renewables are producing the majority of the electricity in the market the prices plummets to zero or even negative since the marginal cost of renewable energy is low or non-existent. Producers might even be willing to pay in order to stay online. Naturally the opposite applies when flexible sources such as gas turbines are online in that the prices peak [32].

In order to reduce the effect of bottlenecks in the transmission network, Sweden is divided into four bidding zones SE1-SE4 as in figure 2.5. These four different price zones might have different volatility since the supply differs between the regions. The transmission capacity between the different regions affects the price in a specific electricity region. This means that a high transmission capacity between regions results in low price-difference between the regions [31].

Figure 2.5: Swedish electricity regions. Source: [33]

2.2.2 Intraday market

As can be understood from the name of "day-ahead market" it is just a forecast of what is likely to happen tomorrow. The "intraday market" exists for correcting imbalances in the day-ahead market. This market is important, especially for wind- and solar generation capabilities, since the weather can change suddenly and thus there is a need for continuous trading. Naturally the "intraday market" is vastly more volatile than the "day-ahead market" [34].

Electricity trading within the Intraday market is continuous and takes place in the framework of "Single Intraday Coupling" (SICD). This framework allows for trading across borders in Europe up to the available transmission capacity. One hour before "Gate closure", ie. electricity delivery, producers can trade in Sweden to ensure their positions are balanced. It is crucial for the producers to ensure their positions are balanced because otherwise the the "Transmission System Operator", TSO can charge expensive imbalance fees [35].

2.3 Variable Renewable Energy

Variable Renewable Energy (VRE) refers to energy sources that are non-dispatchable and stochastic, primarily wind and solar power. Unlike conventional fuel-based generation, VRE output is determined by meteorological conditions rather than consumer demand. As the penetration of VRE increases within the Swedish energy mix, the power system transitions from a system based on stable, rotating inertia to one characterized by high variability, which poses challenges to frequency stability [23, 24].

This shift necessitates a focus on Net Load, the difference between total load and VRE production. When VRE production is high, the net load decreases, potentially leading to negative prices or curtailment [25]. On the other hand, low VRE periods require rapid flexibility from other sources. As a result, the expansion of VRE directly correlates with an increased theoretical requirement for system flexibility and energy storage to manage these shifting load profiles.

2.3.1 Dispatchable baseload

Historically, power generation and stability were anchored by nuclear power, which has generated nearly half of Sweden's electricity. However, the technical landscape is shifting as the proportion of nuclear generation has declined due to the dismantling of older reactors. While there are strategic plans for new large-scale reactors by 2035 and further expansion by 2045, their role in future balancing is technically constrained by high capital intensity and long lead times of 10–15 years [44].

From a system perspective, the uncertainty surrounding new nuclear commissioning highlights a "flexibility gap." Because nuclear plants are traditionally optimized for constant baseload rather than rapid ramping, the projected growth in VRE necessitates alternative technologies that can provide the flexibility that large-scale thermal plants historically lacked.

2.3.2 The "Duck curve"

The term "duck-curve" was coined in 2013 by California Independent System Operator (CAISO) [28]. At first the system state was a theoretical warning but faster than expected turned in to a reality with the ever growing share of solar power added to the grid. This change of power production created a different load for non-renewable sources to cover. It is expected that the belly of the duck would drop so low that traditional plants would have to be throttled down to zero production during the day. The "Duck-curve phenomenon" affects not only solar intense regions like California, Australia and Hawaii but can also be seen in countries such as Germany & the Netherlands during the summer months. Due to the interconnected European electrical grid and with the expansion of residential solar installation the "Duck-curve" is a real phenomenon in Sweden today aswell [26]. The trend can especially be seen during spring- & in summer months where prices regularly reaches below zero around noon. [27].

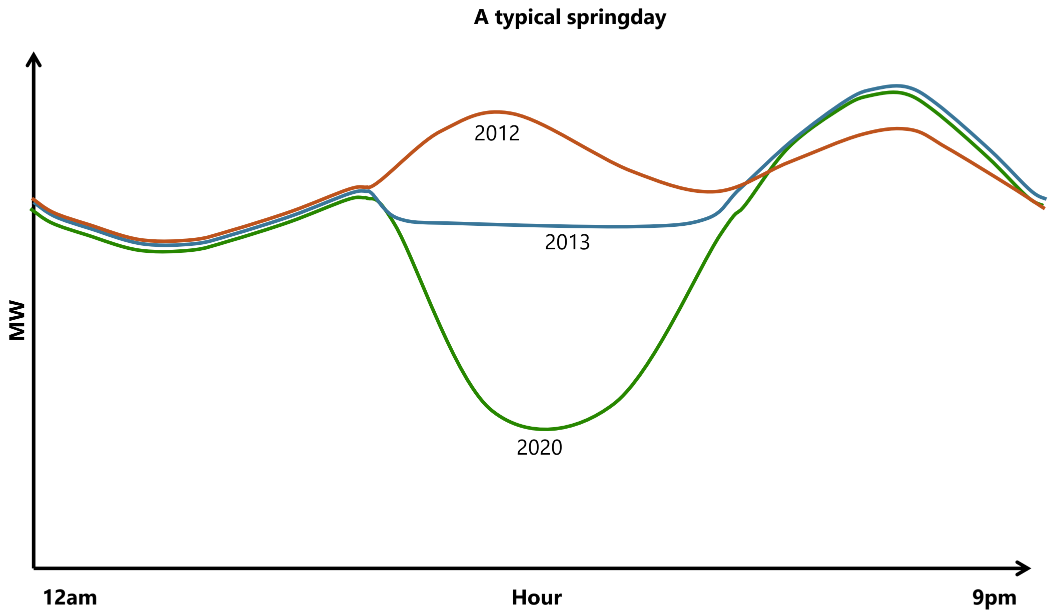

Figure 2.6: Duck curve development, rough estimate. Net-load from California´s electrical grid.

As can be seen in figure 2.6 the curves for 2012 & 2013 represents the previously normal days. Between 2014 & 2017 the increased solar power begun to have some impact on the grid net load. By 2020 the "Duck-curve" could truly be seen taking shape. As of today the belly of the duck continues to grow with expanded solar parks. However Sweden has a large advantage in battling the "Duck-curve" in comparison to California, thanks to its extensive hydropower. Hydropower however, has limitations in how fast it can handle ramps without causing too great frequency deviations in the grid. Additional to handling Swedens own solar penetration, much of the Duck-curve problems are imported from countries with more expanded solar capacities such as Germany. Thus additional flexibility is needed in Sweden in order to meet the goals of a net-zero energy system by 2050 [3]. The phenomenon is a primary driver for energy storage which was initially covered by batteries. Once realizing batteries are not enough a demand for another solution such as P2H2P has become sought after. Because of the steep neck of the duck-curve a relatively quick storage system is needed to charge during maximum solar production and discharge at times of need.

2.3.3 Wind variations

In Sweden, expanding wind generation is steadily displacing the market share of traditional thermal assets, including nuclear and combined heat and power (CHP) plants. Since wind generation is non-synchronous, the electricity system faces a reduction in natural inertia, making the grid more vulnerable to frequency deviations during the rapid onset or termination of windy periods [36]. However, a shifting trend is that wind power has begun to participate in the ancillary services market. This is made possible by equipping wind turbines with control systems, which allows for rapidly pitching turbine blades to reduce output when the grid frequency is too high. This transition marks a move in the low inertia system where wind power only was a challenge for grid stability to becoming a provider of balancing services [37].

While solar power generation follows a predictable diurnal cycle determined by the sun's rising and setting, its short-term output in Northern Europe remains highly stochastic due to variable cloud cover [25]. In contrast, wind power variations are driven by moving large-scale meteorological weather systems rather than daily cycles. Wind power can however have a smoothening effect when distributed over large geographical areas. This is because when it is not windy in one region another might be windy, which on a system scale reduces the overall volatility as long as the areas are well-interconnected [38].

2.3.4 Dunkelflaute

Dunkelflaute is a german term coined to describe periods when little or no energy can be produced by renewable energy sources such as wind and solar [39]. In contrast to the duck-curve that is predictable and driven by the suns cycle, Dunkelflaute is a more stochastic weather driven event. The definition of the phenomenon is to last over one day but the duration is rarely much longer, however it can in some cases last over days. It is stated to occur between two to ten times per year in northern Europe. In general this phenomenon occurs during the winter-months and is due to stagnant high pressure systems sweeping in over northern Europe. The effects it has on the power system are severe since it can occur over a large area and several connecting areas at the same time [39].

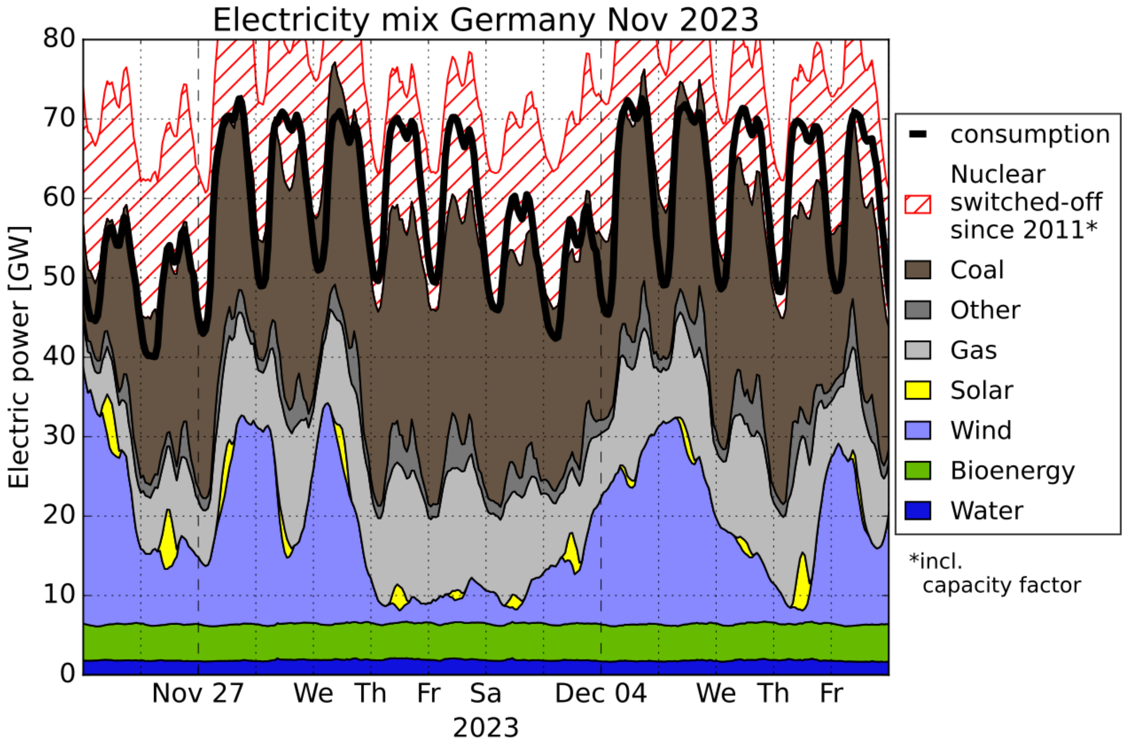

Figure 2.7: Dunkelflaute in Germany 2023 [40]. Figure licensed under CC BY 4.0.

Figure 2.7 shows a time period of the german electricity mix for 2023. As can be seen solar- and wind- production is very limited between Thursday and Saturday resulting in increased coal and gas generation.

According to [39],Dunkelflaute events occur on average between 50 and 100 hours per year in the North and Baltic Sea region. The probability that neighboring countries experiences this energy drought simultaneously is about 30-40%. It was concluded that it is extremely rare to see the entire North-Baltic-sea region to experience energy-drought at the same time. It is suggested that interconnecting the power-system across this region would reduce the frequency of such events occuring from 3-9% in individual countries to approximately 3.5% for the entire region [39]. In the case of Sweden, the stability of the grid during "Dunkelflaute" has been reliant on stored energy in hydropower reservoirs [41]. However, the Swedish hydropower fleet faces strict technical limitations in its balancing capacity, which is constrained to a ramping range of approximately 6–9 GW [23]. Since the total capacity and potential generation variations of Swedish wind power already exceed this threshold, hydropower alone cannot fully compensate for large-scale, system-wide wind fluctuations.

2.4 Wind speed and spot-price correlation

In order to evaluate the impact of wind speed on local electricity spot prices in Gothenburg, they were plotted against each other. Nord Pool market data and the SMHI meteorological observations in "Göteborg A" for 2021, 2022, 2023, 2024 and 2025 were synchronized in Python. A nearest-neighbor method was utilized to ensure that the spotprice aligned with the corresponding wind-speed. This was crucial in order to avoid phase shifts that could deflate the correlation. Electricity spot prices in the SE3 zone exhibit high-frequency volatility due to hourly demand fluctuations. To isolate the underlying relationship between wind velocity and price, a central moving average was applied which acted as a low-pass filter. This smoothing process removed "noise" from intra-day trading and focused the analysis on the macro-relationship between weather patterns and market pricing. The correlation between wind speed and the spot price was quantified using the Pearson correlation coefficient (r), which unlike covariance, provides a dimensionless index between $+1$ and -1. A negative value confirms that the variables move in opposite directions, which is the expected behavior for wind-integrated power market. The correlation analysis was conducted on a monthly basis to account for exogenous variables that vary seasonally within the SE3 zone such as, wind density and turbine efficiency fluctuate with ambient temperature differences between winter and summer. During the spring melt, a massive influx of hydro-power can potentially "mask" the price impact of wind generation. Monthly segmentation allows for the isolation of these periods to better observe the specific wind-price elasticity. Pearson correlation is calculated as in equation 2.1.

$$r = \frac{\sum_{i=1}^{N}(P_i - \bar{P})(W_i - \bar{W})}{\sqrt{\sum_{i=1}^{N}(P_i - \bar{P})^2 \sum_{i=1}^{N}(W_i - \bar{W})^2}} \tag{2.1}$$

Nomenclature:

r	Pearson correlation coefficient.
P_i	Synchronized hourly spot price at observation i [EUR/MWh].
W_i	Synchronized wind speed at observation i [m/s].
$\bar{P}, \bar{W}$	Arithmetic mean of the price and wind speed for the sample period.
N	Total number of observations within the analyzed month.

Table 2.2: Pearson Correlation Coefficient (r) between SE3 Spot Prices and Gothenburg Wind Speed (2021–2025)

Month	2021	2022	2023	2024	2025*
January	-0.193	-0.536	-0.395	-0.348	-0.371
February	-0.077	-0.384	-0.404	-0.612	-0.275
March	-0.299	-0.303	-0.211	-0.296	-0.390
April	-0.265	-0.165	-0.165	-0.486	-0.377
May	0.098	-0.213	-0.068	-0.042	-0.497
June	-0.090	0.010	0.098	-0.191	-0.422
July	-0.073	-0.130	-0.240	-0.200	-0.388
August	0.116	-0.140	-0.235	-0.474	-0.498
September	0.121	-0.124	-0.243	-0.116	-0.340
October	-0.348	-0.424	-0.224	-0.356	-0.321
November	-0.250	-0.357	-0.064	-0.472	—
December	-0.222	-0.391	-0.413	-0.231	—
ANNUAL AVG	**-0.124**	**-0.263**	**-0.214**	**-0.319**	**-0.320**†

—Data unavailable for wind speed.

*15 minute prices instead of hour prices.

†Average calculated based on January–October available data.

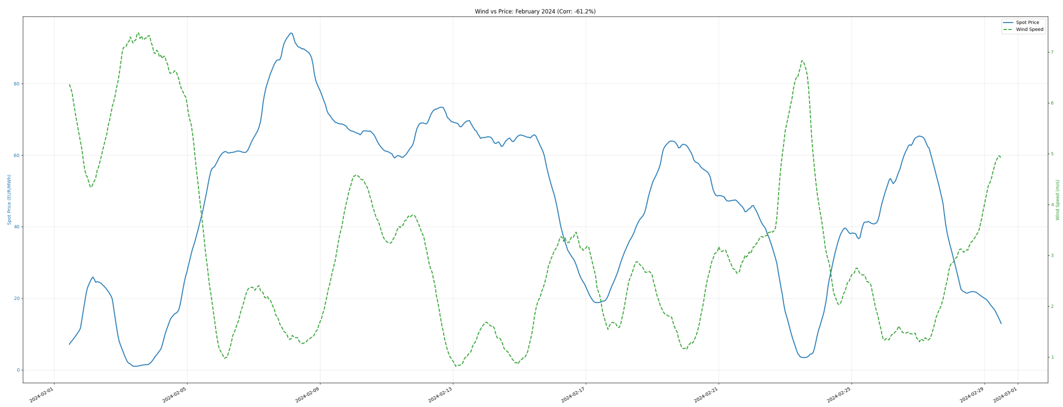

Figure 2.8: Correlation Analysis for February 2024 showing the relationship between Spot Price SE3 (blue [EUR/MWh]) and Wind Speed (green [m/s]) in Gothenburg.

The data in Table 2.2 reveals a predominantly negative correlation, consistent with the economic theory of the merit-order effect, where increased renewable supply with low marginal costs depresses market clearing prices. The strength of this relationship varies somewhat seasonally, with the most pronounced impacts observed during the winter months. Notably, February 2024 exhibited the strongest inverse relationship in the dataset ($r = -0.612$). As illustrated in Figure 2.8, the price trends inversely mirror the wind speed fluctuations, specifically sustained periods of high wind speed correspond with significant "dips" in the EUR/MWh spot price. Some periods, such as June 2023 ($r = 0.098$), show a near-zero or slightly positive correlation. Such anomalies suggest intervals where other market drivers—such as nuclear availability, reservoir levels, solar production, or external demand shock overshadow the influence of local wind production.

It is important to note that the wind-data collected only came from one weather station in Gothenburg, namely "Göteborg A" and is thus no fair representation for all wind data of the entire SE3 region 2.5. It might be that the correlation changes significantly when taking account for all weather-stations in SE3. On top of that, neither the current installed wind-power capacity nor transmission capacities with other electricity bidding regions accounted for. Taking these factor in to account could change the correlations significantly, however this comparison might give a indication of how installed wind capacity today and tomorrow affects and will effect the spot-prices.

2.5 Power-to-heat-to-power

Power-to-heat-to-power (P2H2P) is a broad concept that can be implemented using a cluster of different technological configurations. Regardless of how a P2H2P unit is constructed, it follows the same fundamental principle. In this thesis, P2H2P is defined as *a system that uses electricity purchased from the grid to charge a thermal energy storage unit. Stored thermal energy is later used for the regeneration of electricity or electricity and heat.* The following sections provide a theoretical overview of the main technological components relevant for P2H2P systems, including thermal energy storage technologies, resistive heating combined with power cycles, and pumped thermal energy storage concepts. In addition, the economic drivers, operational trade-offs, and heat utilization potential of such systems are discussed.

2.5.1 Thermal energy storage

Thermal energy storage (TES) units consist of a storage tank equipped with heat injection and heat extraction to and from the storage medium. There are three types of TES systems, which are sensible heat storage (SHS), latent heat storage (LHS) and thermochemical energy storage (TCES). SHS stores energy by increasing the temperature of the storage medium without phase change whereas LHS relies on heat created during phase changes, usually from solid to liquid. TCES stores heat via endothermic reactions during heat injection and releases it through exothermic reactions during heat extraction [49].

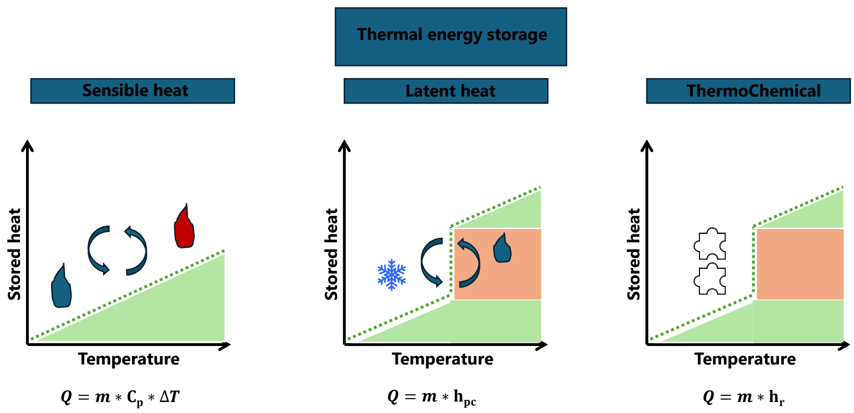

Figure 2.9: The three different types of TES.

SHS systems are the most mature and cost-effective TES option, with low specific costs largely due to inexpensive storage media such as rocks, sand or molten salts. LHS, using phase change materials, provides higher energy densities but at significantly higher costs driven mainly by the need for enhanced heat transfer equipment. TCES theoretically achieves the highest storage capacity and efficiency, while being able to operate at high temperatures, but remains the most complex and costly option reflecting the expensive machinery required for complex heat- and mass-transfer systems [50].

For large-scale and high-temperature applications, SHS materials are predominantly used due to their simplicity and cost efficiency. In contrast, LHS systems are more commonly applied in low temperature storage, often used for improving indoor thermal comfort related to building technology, where high energy density is advantageous. TCES is still largely confined to research and development and has seen limited deployment. In terms of material selection for SHS, water, inorganic salts, thermal oils, sand and gravel are the most widely used because of their low cost and availability [48].

TES is commonly used in conjunction with concentrated solar power (CSP), with molten inorganic salt being the most widely employed storage medium [52]. Thermal energy storage tanks used in CSPs exhibit high thermal efficiency. Losses to the surroundings are primarily governed by heat transfer through insulation and can be minimized through appropriate tank design and insulation strategies [52]. Reported thermal losses are generally low. The Danish Energy Agency [51] reports daily losses of approximately 0.75% for molten salt storage systems and as low as 0.1% for low-temperature (150–250 °C) rock-based carnot battery systems.

Study [65] found that for large-scale TES units operating under frequent cycling, the impact of insulation can be bypassed. This is due to strong thermal inertia in massive storage volumes and a favorable surface area to volume ratio since the heat loss area grows more slowly than capacity increases. Although the same study highlights that these are not universal but case-specific results, for smaller-scale storage and for seasonal storage insulation becomes an important design parameter [65].

2.5.2 Resistive heating + power cycle

In power-to-heat-to-power applications, thermal energy can be generated through resistive electrical heating, where electricity is directly converted into heat via the Joule effect. This approach is characterized by high conversion efficiency, technological simplicity, and broad applicability across a wide temperature range, making it suitable for thermal energy storage systems [46].

Heat-to-power conversion technologies applicable for thermal energy storage are usually Rankine-based or Brayton-based [47]. In conventional CSP plants with thermal energy storage, steam Rankine cycles remain the dominant solution [52]. In parallel, research interest is increasing in "supercritical CO_2" (sCO_2) Brayton cycles, which highlights their promising potential for P2H2P applications, driven by the higher efficiency of sCO_2 cycles at elevated operating temperatures and compact turbomachinery [47].

The different combinations of TES with power cycles allow for significantly varying operating temperature ranges from 200 °C to 1200 °C. At lower temperatures (up to 350 °C), Organic Rankine Cycles (ORCs) tend to be most cost-effective but exhibit relatively low thermal-to-electric efficiency. In the intermediate temperature range, steam Rankine cycles remain the best option with a somewhat higher efficiency for storage temperatures between 350 °C and 600 °C. At higher temperatures (600–950 °C), sCO_2 Brayton cycles with advanced configurations such as recompression and intercooling become the preferred option due to their higher thermal-to-electric efficiency and compact footprint [47].

Heat-to-power efficiency losses are arguably the biggest issue with resistive-charging-based P2H2P solutions. As a reference using resistive heating and steam turbine expansion, round-trip efficiency is typically limited to below 40% [51]. Increasing the turbine inlet temperature of the heat-to-power cycle generally improves the thermal-to-electric conversion efficiency. However, higher operating temperatures require more complex cycle configurations and advanced materials, which increase system complexity and investment costs [47]. Figure 2.10 represents the basic structure of a resistive electric heating + power cycle configuration.

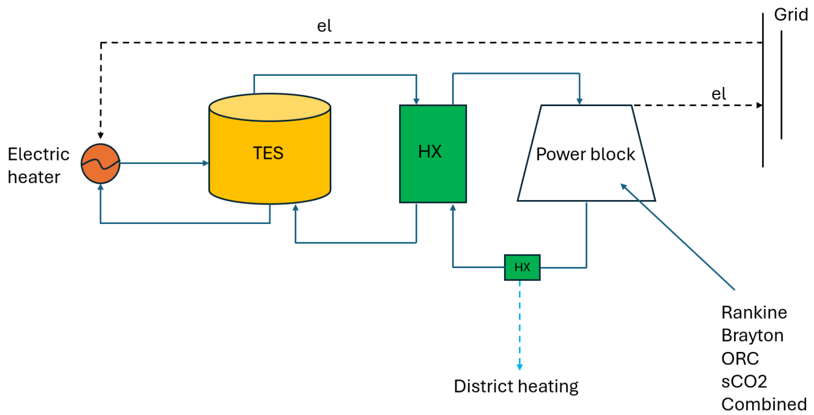

Figure 2.10: Resistive heating + power cycle P2H2P system

2.5.3 Pumped thermal energy storage

Pumped thermal energy storage (PTES) is widely regarded as the most promising configuration for P2H2P. It operates on a reversible cycle capable of achieving higher round-trip efficiency compared to decoupled systems based on resistive electric heating and a separate power cycle. PTES systems are achieved through a reversible heat pump/heat engine cycle operating in two modes with a hot and a cold storage tank. During charging, the cycle functions as a heat pump. The working fluid absorbs heat from the cold storage and with the help of electrical work supplied to a compressor, increases its temperature and pressure before transferring heat to the hot storage. During discharging, the cycle operates as a heat engine, the stored heat is extracted from the hot reservoir, expanded through a turbine to generate power, and the remaining heat is rejected back into the cold reservoir. Simultaneously, the turbine drives a compressor at the other end of the heat engine to increase the temperature of the fluid circulated from the cold to the hot storage [58]. Figure 2.11 and 2.12 show the charging and discharging setups, respectively for a simple PTES system.

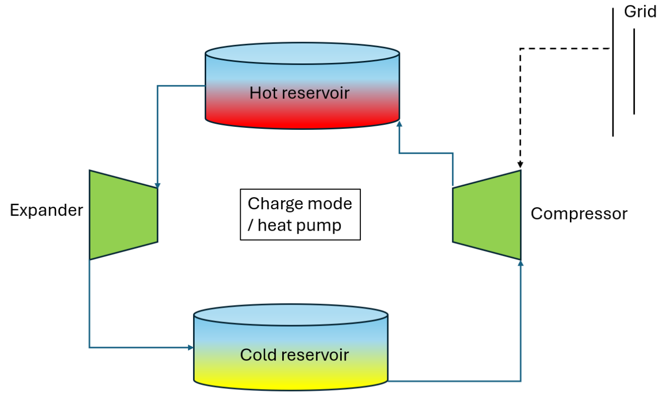

Figure 2.11: Charge mode PTES

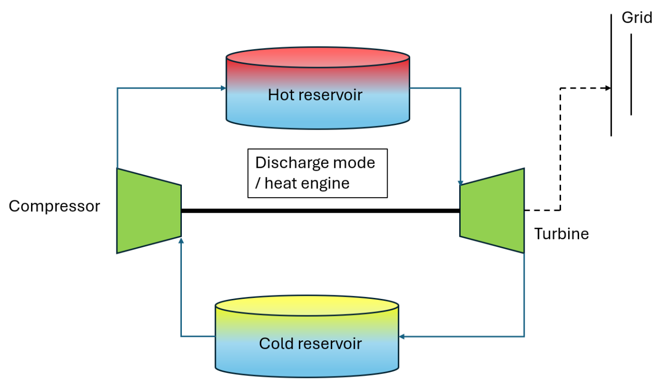

Figure 2.12: Discharge mode PTES

In comparison to the resistive heating + power cycle solutions the PTES system appears more promising in terms of electrical round-trip efficiency, the Gridscale project [61] operated by the Danish company Steisdal claims to have an expected electric round-trip efficiency of 55-60% and with integrated spill heat recovery propelling the total RTE to 90%. The PTES potential has also been academically highlighted by a study that reached a roundtrip efficiency above 70 % with a complex choice of working fluid medium and high working temperature [65].

There are a few different solutions proposed academically, and in a few cases pilot-demonstrated PTES power cycle solutions. The main configurations include Joule–Brayton and conventional Rankine cycles. Joule–Brayton systems typically use gas-based compression and expansion at high temperatures with sensible heat storage, often in packed beds or liquid tanks. They are strongly dependent on turbomachinery performance and realistically achieve 40–60% electrical round-trip efficiency in practice. Rankine systems operate at lower temperatures using liquid sensible or latent heat storage. They are less sensitive to turbomachinery efficiency and a round-trip efficiency around 50–60% is expected under realistic conditions [64].

While Figures 2.11 and 2.12 reflect how a simple PTES system operates, they can become increasingly more complex than the figures above. The pilot project demonstrated by the U.S.-based company Malta Inc. [63] demonstrates a solution with a steam-based conventional Rankine cycle, two hot storage tanks alternating between "hot" and "warm" temperatures, heat exchangers between the storage medium (molten salt) and the steam, as well as an evaporator before the compressor stage, which partly utilizes imported residual heat, and a third cold water tank before the evaporator.

Study [65] proposes a configuration based on an air Brayton cycle coupled with a bottoming organic Rankine cycle. The system is integrated with a two-tank molten salt thermal energy storage system. Multiple high-temperature heat exchangers are used to transfer heat between the different subsystems. These enable heat recovery, storage, and reuse throughout the system.

Study [65] and the Malta Inc pilot demonstration are in large contrast to the solution proposed by the Danish company Stiesdal, a far less complex solution with a simple air Brayton integrated cycle with crushed rock as the storage medium. Ultimately allowing the rocks to act as the heat exchanger surface, limiting the use of the industrial heat exchangers between different working fluids [61].

In PTES systems, electrical round-trip efficiency is typically defined assuming that all heat within the cycle is internally recovered and ultimately reconverted into electricity. If heat is instead extracted for external heating applications, for example from the turbine outlet before recirculation to the cold reservoir, the electrical round-trip efficiency likely decreases since part of the thermal energy is diverted from the internal recovery process of the cycle [58]. Although very limited research has quantified the exact impact of external heat extraction on PTES performance, the thermodynamic trade-off between heat utilization and electricity recovery remains evident.

2.5.4 Economic drivers

Operational expenditures (OPEX) are primarily driven by the price of electricity during charging. In Sweden, electricity consumption is also subject to an energy tax. As of 2026, the electricity tax is approximately 450 SEK/MWh including VAT [59]. However, it remains unclear whether P2H2P applications qualify for tax exemptions. Swedish legislation states that electricity used for electricity production can be exempt from the consumption tax. At the same time, this study investigates the advantages of P2H2P systems capable of producing useful heat. Currently electricity used for producing residual heat is not exempt from the electricity consumption tax [60].

The capital expenditure (CAPEX) of PTES systems is primarily governed by operating temperature levels and overall system complexity. Higher operating temperatures generally improve round-trip efficiency. However, they also significantly increase system CAPEX. This is largely due to the strong temperature dependence of turbo-machinery components, as compressors and turbines designed for elevated operating temperatures are substantially more expensive [65]. Furthermore, the low heat-transfer coefficients associated with gas-based systems require larger heat-transfer areas, resulting in larger and more costly heat exchangers. Heat exchangers can thus constitute a significant share of the total system CAPEX [65].

As discussed in Section 2.5.1, the storage medium itself can be relatively inexpensive, particularly in SHS systems [50]. Nevertheless, the overall CAPEX remains strongly influenced by storage-related parameters such as the heat-transfer characteristics of the storage medium and the operating temperature, both of which affect system complexity and heat-exchanger requirements [65]. Additionally, as the energy storage capacity increases while the turbo-machinery capacity remains fixed, the levelized cost of energy decreases since only the storage subsystem must be expanded. This highlights the economic advantage of scale for long-duration storage applications [65].

2.5.5 Heat utilization

The potential of heat utilization from P2H2P systems is not commonly academically studied, especially for PTES systems, where most academic articles reviewing PTES focus on electrical round-trip efficiency optimization and treats waste heat as an exergy loss. However forerunners for P2H2P projects [61, 63] claim to have a very high total energy roundtrip efficiency reaching 85-90 % when producing electricity and heat. As discussed briefly in Section 2.5.3 from a thermodynamic perspective, heat extraction during discharge introduces a trade-off between electrical and total system performance. Since irreversibilities in compression, expansion, and heat transfer already limit efficiency, diverting heat from the cycle reduces the available exergy for power generation and thus lowers electrical round trip efficiency [66].

This aspect is also closely linked to system cost. Heat exchangers can represent a major share of total CAPEX in a PTES system, largely dependent on the heat transfer coefficients of the working fluids, where low heat transfer coefficients require large heat transfer areas. As a result, increased heat extraction and thermal integration may further increase heat exchanger size and associated costs. This introduces an additional trade-off between improved energy utilization and capital expenditure [65].

Recent studies suggest that heat utilization should not be regarded solely as a loss mechanism. Exergy analyses indicate that major losses are concentrated in expanders and low-temperature heat exchangers. Extracting heat at appropriate locations particularly at low temperature levels, can therefore recover energy that would otherwise be rejected, partially offsetting efficiency losses and improving overall system performance [64].

2.5.6 Dynamic limitations

The dynamic response of P2H2P systems is likely constrained by both turbomachinery and thermal components. While compressors and turbines can achieve relatively high ramp rates once in operation, the transition from standstill to full load is significantly slower, with typical start-up times on the order of tens of minutes. In combined cycle systems, the coupling between the power cycle and the heat recovery unit introduces additional dynamic constraints. In particular, systems involving heat extraction or transfer through heat exchangers are limited by thermal inertia and allowable temperature gradients. Rapid temperature changes can induce thermal stress, creep, and fatigue in structural components, requiring controlled ramping of temperature and load [67].

2.6 Techno-economic performance indicators of storage technologies

To contextualize the performance of P2H2P systems relative to alternative storage technologies, both economic and efficiency performance indicators are compared in this section. The Levelized Cost of Storage, (LCOS) is the main economic metric used to compare and evaluate the economic performance of different energy storage technologies. LCOS is used in this thesis study, thus further detailed in Section 3.7 in the methodology chapter. A comparative assessment of LCOS for different energy technologies gathered from [71] is presented in Table 2.3. This comparison assumes a fixed electricity charging price of 30 EUR/MWh and a cycling frequency of 365 cycles per year. At a power-to-energy ratio of approximately 100 MW / 400 MWh [71].

Table 2.3: Reported LCOS values for different energy storage technologies adapted from [71]. Values converted using an exchange rate of 11.13 SEK/EUR.

Technology	**LCOS**	**Unit**
PTES	990–1270	SEK/MWh
CAES	750–1960	SEK/MWh
Pumped Hydro Storage	530–1810	SEK/MWh
Lithium-ion battery	2560–4120	SEK/MWh
Hydrogen storage	2000–2900	SEK/MWh

The values presented in Table 2.3 indicate the economic competitiveness potential of PTES systems under large-scale, multi-hour storage operation.

The round-trip efficiency of different energy storage technologies is presented in Table 2.4.

Table 2.4: Efficiency performance of various storage technologies and projects.

Type	**Elec. RTE**	**RTE with heat utilization**	**Source**
Resistive heating + power cycle	<40%	90%	[51]
PTES Rankine	50–60%	- %[a]	[64]
PTES Joule-Brayton	40–60%	- %[a]	[64]
Energy Dome - CO2 battery	75+%	-	[53]
GridScale	55–60%	90%	[61]
Malta Inc.	55–60%	85–95 %	[63]
CAES (Adiabatic)	65–75%	-	[42]
Li-ion batteries	90–95%	-	[43]
Pumped hydro	70–85 %	-	[74]
Hydrogen	30–40%	-	[72]

[a] Can provide DH at expense of decreased electric RTE, Total-RTE/Electrical-RTE ratio dependent on many factors and are as of today not academically studied enough for grounded estimates.

Values are based on realistic estimates or actual pilot demonstrations like the Malta inc. project, not the technology's technical potential, which is often substantially higher. Another emerging technology similar to PTES systems presented in Table 2.4 is the CO_2-battery developed by the Italian-based company Energy Dome. The system stores energy using closed-loop CO_2 compression and expansion cycles combined with thermal energy recovery, and is reported to achieve electrical round-trip efficiencies of at least 75% [53].

3 Methodology

This thesis applies a dual-modeling approach to analyze the economic performance of a representative P2H2P system under varying electricity market conditions, district heating system configurations, policy scenarios and operational strategies.

The system is assumed to be sufficiently small enough that its operation does not influence the power system. However, the interaction between the P2H2P system and the district heating network is explicitly considered in the analysis. Both models utilize electricity price data from the SE3 bidding zone for the years 2023, 2024 and 2025, while district heating production capabilities, associated fuel costs and heat demand data for the year of 2024 for the Gothenburg district heating system were provided by GE.

3.1 Scenario design

A set of model scenarios was developed which explore how external market conditions and internal operational assumptions influence the value of the storage system. The reference case is based on 2024 market data and serves as the primary benchmark. In this case, the P2H2P unit operates as a CHP unit, both with and without the swedish electricity consumption tax. Additional scenarios included inter-annual variations using 2023 and 2025 market data. These years are characterized by higher electricity price volatility and are included to assess the sensitivity of system performance to price fluctuations. Additionally one scenario considered a district heating system configuration where the excess heat used for DH, which in Gothenburg consist of a large part of total heat production, is replaced by biomass-fired CHP production. This setup is intended to better represent a typical Swedish district heating system. Finally, a scenario was included in which the system operates solely for electricity generation without heat recovery. Table 3.1 provides an overview of all modeled scenarios.

No.	Scenario	Year	Tax	Description
1	Reference case	2024	No	Benchmark case.
2	Reference case	2024	Yes	Benchmark case with electricity consumption tax.
3	Year variation	2023	No	Reference configuration using 2023 data.
4	Year variation	2025	No	Reference configuration using 2025 data.
5	Excess heat replaced	2024	No	Biomass-fired CHP replaces excess heat.
6	Electricity only	2024	No	Operation without heat recovery.

Table 3.1: Overview of model scenarios for the P2H2P system.

Sensitivity analyses are additionally performed for CAPEX assumptions, storage duration and the markets temporal resolutions. The applied sensitivity cases are described in Section 3.4.

3.2 P2H2P system representation

One distinct efficiency metric is governing the technical performance of a P2H2P system. The *Electrical Round-Trip Efficiency* η_{elec} which consequentially evaluates electricity price arbitrage utilization efficiency (Eq. 3.1).

$$\eta_{elec} = \frac{E_{el,out}}{E_{el,in}} \tag{3.1}$$

Where:

- $E_{el,out}$ and $E_{el,in}$ are the discharged and charged electrical energy, respectively.

For a pure electricity arbitrage scenario, if assuming negligible thermal losses the price ratio between discharging price (λ_{dis}) and the discharging price (λ_{ch}) must satisfy the condition:

$$\frac{\lambda_{dis}}{\lambda_{ch}} > \frac{1}{\eta_{elec}} \tag{3.2}$$

Heat output is estimated using a simplified combined heat and power analogy, where the remaining thermal energy from the power cycle can be recovered through a heat exchanger. The resulting heat utilization efficiency is therefore defined as:

$$\eta_{heat} = (1 - \eta_{elec}) \cdot \eta_{HX} \tag{3.3}$$

Where:

- η_{hx} is the efficiency heat exchanger connected to the district heating system which is assumed to be 90% [76].

The discharge of useful power and heat of the P2H2P unit will consequently be distributed between electricity production and useful heat according to:

$$P \rightarrow \begin{cases} \eta_{elec} P_{out,th,t} & \text{electricity output} \\ \eta_{heat} P_{out,th,t} & \text{heating output} \end{cases} \tag{3.4}$$

Where:
- $P_{out,th,t}$ is the thermal output leaving the storage (MW_{th})

The state of the thermal storage inventory (TES energy balance) is updated at each time step. It incorporates losses to account for thermal runway over extended storage durations in accordance with equation (3.5)

$$E_{TES,t+1} = E_{TES,t} \cdot \gamma + P_{in,t} \cdot \Delta t - P_{out,th,t} \cdot \Delta t \tag{3.5}$$

The daily energy loss factor accounting for thermal losses to the surrounding is set to 1%. The hourly retention time is calculated from the loss factor δ in the following way:

$$\gamma = (1 - 0.01)^{1/24} \tag{3.6}$$

Where:
- $P_{in,t}$ is the thermal power input into the storage (MW),
- $E_{TES,t}$ = thermal inventory at each time step (MWh_{th})
- γ is the storage retention efficiency accounting for standing thermal losses.

When the P2H2P unit operates as a CHP unit, the electrical round-trip efficiency is assumed to be 35%. When operating in electricity-only mode, the round-trip efficiency is assumed to be 55%, reflecting the performance of a realistic PTES system.

Table 3.2: Operational efficiency and thermal loss assumptions for the studied scenarios.

Scenario	η_{elec}	η_{heat}	Daily thermal losses δ [71]
1 Reference case 2024	0.35	0.585	1%
2 Reference case 2024 with tax	0.35	0.585	1%
3 Year variation 2023	0.35	0.585	1%
4 Year variation 2025	0.35	0.585	1%
5 Excess heat replaced with biomass CHP	0.35	0.585	1%
6 Electricity only (no heat recovery)	0.55	0.00	1%

3.3 Modeling framework

The systems are modeled as integrated energy hubs comprising a series of interconnected conversion and storage stages. This configuration focuses on the transformation of electrical energy into high-grade thermal inventory and its subsequent recovery for the power and heating sectors. The technical boundaries and operational constraints of these components are defined by the thermodynamic efficiency parameters found in table 3.2. The systems are constrained by a maximum thermal discharge rate ($30.0\,MW_{th}$) and a maximum electrical charge rate of ($10.0\,MW_{el}$), creating an asymmetric charging/discharging profile that favors rapid heat extraction leaving the storage unit. The TES unit capacity is determined by discharging hours relative to the discharging capacity according to equation (3.7)

$$E_{TES}^{max} = N_{hours} \cdot 30MW_{th} \tag{3.7}$$

Global constraints were defined in an attempt to streamline the two models so their only essential difference would be that their charge and discharge logic differs.

- **Time Horizon and Resolution:** The simulations covers a full calendar year (8,760 hours) to capture seasonal variations in both electricity volatility and district heating demand. The 2023, 2024 and 2025 datasets are analyzed at a 1-hour resolution. These resolutions are selected to align with the Nord Pool Day-Ahead market and the hourly demand profiles of Gothenburg DH market. 2024 is the only year for which hourly Gothenburg DH demand fluctuation data was available.

- **Input Data Handling:** Historical price profiles are sourced from ENTSO-E via Excel datasets. The models cleans and synchronizes these timestamps with those of Gothenburg-DH demand profile. To maintain consistency across different years, the model utilizes a *Time-Step Fraction* (Δt) that adjusts energy flows (MWh) relative to the data resolution.

- **Assumptions:** For the purpose of this simulation, conversion efficiencies (η) are assumed to be constant across the full range of operation.

- **Pattern recognition:** The simulation models does not differentiate between weekday and weekend spot-price behaviors, which may cause it to overlook subtle patterns in intra-week demand fluctuations.

3.3.1 Volatility difference between 2023, 2024 and 2025

To estimate how volatile the SE3 bidding zone was in 2023 and 2025 relative to the 2024 reference case, a robust volatility measure is applied. Volatility was measured as the difference between the 95th and 5th percentiles of hourly price changes, calculated as:

$$\Delta P_t = P_t - P_{t-1}.$$

For each year, volatility is given by

$$\text{Volatility} = P95 - P5.$$

This percentile-based measure captures the spread of the central 90% of observations while reducing sensitivity to extreme values, thereby providing a robust estimate of typical price variability.

To enable comparison, the relative change in volatility for 2023 and 2025 is calculated with respect to the reference year 2024 as

$$\Delta V_{\text{year}} = \left(\frac{(P95 - P5)_{\text{year}}}{(P95 - P5)_{2024}} - 1 \right) \times 100.$$

3.3.2 Defining the value of district heat production

The revenue associated with district heating is quantified as the avoided cost for Göteborg Energi as the system operator. The heat generated from the P2H2P plant replaces the most expensive production unit every time it is activated. This approach reconstructs the system's merit order of the district heating system in Gothenburg. The value of producing heat is calculated as the delta between the total system production cost with and without the P2H2P injection. This methodology captures the system-wide effect of displacing marginal peak-load fuels. This approach is inherently biased towards the system operator perspective. A stand-alone heat producer participating in the system would not necessarily benefit from reduced total system production cost.

3.3.3 Model 1

For Model 1, the operational behavior of the P2H2P unit was determined using a linear optimization model developed for this study. The model compares the total annual district heating system running cost with the P2H2P unit to the total annual district heating cost without the P2H2P unit. Where the total amount of electricity sold is represented as a negative production cost. The difference in total system cost with and without the P2H2P unit ultimately becomes the yearly value of implementing the system: V_{P2H2P} (Eq. 3.10). The optimization problem is implemented in Python using the Pyomo optimization framework. The model is solved using the HiGHS solver.

Linear optimization is a method used to minimize or maximize a linear objective function subject to a set of linear constraints. In this approach, the objective is to minimize the total annual operational cost of the district heating system. The objective function therefore represents the total yearly heat production cost (Eq. 3.8 - 3.9). The decision variables include charging, discharging,the energy level of the TES unit, and the heat production from each existing district heating producer.

The model iterates the use of each variable to form the optimal solution at each hour.

To avoid unrealistic high frequency cycling, which is often observed in linear models with perfect foresight, a cycling penalty was introduced. This penalty is proportional to the total charged and discharged energy and discourages the model from reacting to small and short price fluctuations thereby prioritizing more meaningful price differences. The penalty term is included directly in the objective function (Eq. 3.9). Furthermore, a global constraint limits the amount of energy cycled through the TES system also for preventing excessive cycling (Eq. 3.11). Both constraints cause the model to account for costs and limitations that in reality do not reflect true system degradation. However, the constraints are motivated by the need to eliminate the need for binary variables keeping model complexity limited. The model considers TES capacities of 360, 720, 1440, and 2160 MWh, corresponding to storage durations of 12, 24, 48, and 72 hours at 30 MW_{th} discharge.

Objective functions:

$$C_{sys} = \min \Delta t \sum_{t \in T} \left(\sum_{i \in I} c_{i,t} q_{i,t} \right) \tag{3.8}$$

$$C_{sys}^{P2H2P} = \min \ \Delta t \sum_{t \in T} \left(\sum_{i \in I} c_{i,t} q_{i,t} + (c_{tax} + \lambda_t) P_{in,t} - \eta_{elec} \lambda_t P_{out,t} + c_{cyc} (P_{in,t} + P_{out,th,t}) \right) \tag{3.9}$$

Yearly value of P2H2P:

$$V_{P2H2P} = C_{sys} - C_{sys}^{P2H2P} \tag{3.10}$$

where:
- C_{sys}^{P2H2P} = total annual system cost with the P2H2P unit (SEK)
- C_{sys} = total annual system cost without the P2H2P unit (SEK)
- T = set of time periods
- I = set of heat production units
- $c_{i,t}$ = variable heat production cost of unit i at time t (SEK/MWh)
- $q_{i,t}$ = heat production from existing unit i at time t (MW)
- c_{tax} = electricity consumption tax (SEK/MWh)
- c_{cyc} = cycling penalty (SEK/MWh)
- λ_t = electricity price at time t (SEK/MWh)
- V_{P2H2P} = annual value of P2H2P unit (SEK)

Decision variables:
- $q_{i,t}, \quad \forall i \in I,\ t \in T$
- $P_t^{in},\ P_{out,th,t},\ E_{TES,t}, \quad \forall t \in T$

Constraints: Apart from the energy storage balance represented by equation (3.5) above, the model is constrained by the following operational constraints.

Cycling constraint:

$$\sum_{t \in T} P_{in,t} \cdot \Delta t \leq N_{cycles} \cdot E_{TES}^{max} \tag{3.11}$$

Heat balance for system without P2H2P unit:

$$\sum_{i \in I} q_{i,t} = D_t, \quad \forall t \in T \tag{3.12}$$

Heat balance for system with P2H2P unit:

$$\sum_{i \in I} q_{i,t} + \eta_{heat} P_{out,th,t} = D_t, \quad \forall t \in T \tag{3.13}$$

Where:
- D_t = heat demand at time t (MW)

Operational limits

$$0 \leq q_{i,t} \leq q_i^{max}, \quad \forall i \in I, \ t \in T \tag{3.14}$$
$$0 \leq P_{in,t} \leq P_{in}^{max}, \quad \forall t \in T \tag{3.15}$$
$$0 \leq P_{out,th,t} \leq P_{out}^{max}, \quad \forall t \in T \tag{3.16}$$
$$0 \leq E_{TES,t} \leq E_{TES}^{max}, \quad \forall t \in T \tag{3.17}$$

where:
- q_i^{max} = rated capacity for each existing heat producer (MW)
- $P_{in}^{max} = 10 MW_{el}$
- $P_{out}^{max} = 30 MW_{th}$
- $E_{TES}^{max} = N_{hours} \cdot 30 MW_{th}$

3.3.4 Model 2

A second model was developed from scratch, starting by studying the behavior of the spot-prices. One objective was to redistribute the natural fluctuations of wind and solar variations. The initial idea was to buy as cheap electricity as possible and sell it at the spot-price peaks, called electricity arbitrage. The period for storing energy was assumed to be up to one week since the primary objective was to cover wind variations. For longer storage periods other options but P2H2P are assumed to be cheaper.

The simulation was implemented in Python and utilized a rule-based, deterministic dispatch to evaluate the system's economic performance and behavior. Unlike static models, the strategy was built upon a revenue maximization priority coupled with behavioural constraints ie. limiting battery like behavior. At the end of the day the focus was on maximizing the value stack through the integration of electricity arbitrage and DH savings in Gothenburg DH-network.

The model's decision-making process is governed by a dual-trigger mechanism that monitors price volatility against historical trends. The system evaluates the current spot price (P_{spot}) against a 168-hour (7-day) exponential moving average (EMA_{168h}) to establish a procurement threshold. For discharging, a double exponential moving average ($DEMA_{720h}$) is employed to identify stable selling windows. After talks with an in-house expert on the field a foresight window of 72 hours was applied, implemented as a rolling horizon to the electrical dispatch. Within the 72-hour foresight window, the model is assumed to have perfect knowledge of upcoming prices to optimize peak hunting. The algorithm calculates the 70th percentile of prices within the 72 hour foresight window and discharge is only initiated if the current price exceeds this "peak" threshold and satisfies the profit multipliers (M) controller which currently is set to 1. This logic ensures that the thermal inventory is preserved for high-value volatility events rather than being depleted during minor daily fluctuations.

In each hour, the model assesses data streams such as electrical spot prices (EUR/MWh) historical price trends, SoC of the TES, DH maginal cost and efficiency-adjusted capacity limits. The simulation varies the TES tank capacities to identify the optimal storage duration, focusing on pre-validated sizes of 12, 24, 48, and 72 hours. These durations represent the timeframe required for a full discharge at maximum thermal capacity. To optimize the operational strategy, the simulation permutes charging thresholds (0.5 to 1.2) and profit multipliers (M) ranging from 1.0 to 1.7. In this framework, the profit multipliers functions as a dynamic hurdle rate. While a baseline value of $M = 1.0$ ensures nominal break-even operation, higher values account for the opportunity cost of energy. By requiring a specific profit margin before triggering a discharge, the model evaluates the trade-off between immediate lower-value arbitrage and the potential for higher-value peaks later in the week. This ensures the TES unit is utilized as a strategic asset rather than a simple high-frequency buffer. The charging threshold dictates procurement behavior where a threshold of 0.5 represents conservative charging during extreme price valleys, while a 1.2 threshold allows for procurement even when prices are slightly above the weekly average. These loops are intended to identify the 'Pareto-effective' configuration that minimizes the project's PBP.

The primary financial indicator used to evaluate the system's viability is the annual net cash flow (NCF) which for compatibility reasons will be named "V_{P2H2P}". This represents the total surplus generated by the plant after accounting for electricity procurement. Based on the simulation logic, it is defined as:

$$V_{P2H2P} = \sum_{t=1}^{T}(R_{el,t} + R_{heat,t}) - \sum_{t=1}^{T}(C_{el,t}) \tag{3.18}$$

where:

- V_{P2H2P} is the annual net profit [SEK],
- $R_{el,t}$ is the revenue from electrical discharge at time t [SEK],
- $R_{heat,t}$ is the revenue from recovered heat (avoided cost) at time t [SEK],
- $C_{el,t}$ is the cost of electricity procurement for charging at time t [SEK].

The individual components of the annual net profit are derived from the hourly energy flows and the prevailing market prices. The electrical revenue ($R_{el,t}$) is a function of the electrical discharge and the electricity spot price:

$$R_{el,t} = P_{out,th,t} \cdot \eta_{elec} \cdot \lambda_t \cdot \Delta t \tag{3.19}$$

The heat revenue ($R_{heat,t}$) is calculated using the *Avoided Cost* principle. Rather than a fixed price, it represents the marginal savings in the district heating (DH) system production:

$$R_{heat,t} = \sum_{i \in I} c_{i,t} \left(q_{i,t}^{\text{base}} - q_{i,t}^{\text{P2H2P}} \right) \tag{3.20}$$

The electricity procurement cost ($C_{el,t}$) for charging the thermal inventory includes both the spot price and any applicable taxes:

$$C_{el,t} = P_{in,t} \cdot (\lambda_t + c_{tax}) \cdot \Delta t \tag{3.21}$$

where:

- $q_{i,t}^{\text{base}}$ = heat production from existing unit i during time step t in the baseline scenario (without the P2H2P system operating) (MWh/h)
- $q_{i,t}^{\text{P2H2P}}$ = heat production from existing unit i during time step t in the P2H2P scenario (with the P2H2P system integrated and operating) (MWh/h)

3.4 Sensitivity analysis

Investment costs for P2H2P are under considerable uncertainty. To account for this uncertainty, this thesis uses a lower, control, and upper CAPEX value, where lower and upper represent a 20 % decrease and increase from the control value respectively. Furthermore, as discussed in Section 2.5.4 P2H2P systems have a theoretically scalable storage unit, making storage scale (MWh/MW) a key economic factor. However, the economically optimal scale is likely constrained by the market conditions. To investigate this effect, four different storage scales are applied at “12, 24, 48, and 72 hours of discharge duration as described in Models 1 and 2. The sensitivity analysis additionally evaluates how the economic performance of the P2H2P system is affected by the assumed operational ability to exploit short-term electricity price fluctuations using a 15-minute market resolution compared to an hourly resolution. Since 15-minute electricity price data were only available for 2025, this analysis is limited to the 2025 market scenario. Table 3.3 summarizes the sensitivity parameters considered in this study.

Parameter	Values
CAPEX	Lower, Ctrl, Upper
Storage scale ($E_{TES}^{max}/P_{out,th,t}$)	12, 24, 48, 72
Temporal price resolution	Hourly, 15-minute

Table 3.3: Sensitivity parameters considered in the analysis.

3.5 Economic evaluation

The results are evaluated using two *key performance indicators* (KPIs), namely the profitability index (PI) and the payback period (PBP).

The techno-economic performance is determined by the annual system value of the P2H2P operation relative to the annualized capital cost of the P2H2P system, expressed as a profitability index according to equation (3.22).

$$PI = \frac{V_{P2H2P}}{CAPEX_{ann}} \tag{3.22}$$

- V_{P2H2P} = annual value of the P2H2P storage system
- PI = profitability index, where $PI > 1$ indicates that the investment is profitable and $PI < 1$ indicates that the investment is not profitable

To complement the profitability index, the economic performance of the system is also evaluated using the simple payback period (PBP). This metric estimates the expected time required for the system to recover its initial investment cost through annual net cash flows. Although the simple PBP does not account for the time value of money, it serves as a robust baseline for comparing the capital recovery time of different system configurations.

$$PBP = \frac{CAPEX}{V_{P2H2P}} \tag{3.23}$$

3.6 Cost assumptions

The CAPEX for the P2H2P configuration is based on a PTES Joule-Brayton cycle connected to sensible TES units. The cost assumptions for the charge system, discharge system, electrical system integration and overhead costs were primarily based on industrial benchmark data obtained through confidential communication. Since the underlying source cannot be disclosed, the values were cross-checked against available techno-economic assessments of PTES battery systems, particularly from [71]. The thermal energy storage cost assumption was derived from publicly available literature [71, 51]. Table 3.4 summarizes the applied cost assumptions. For all cost calculations, a currency exchange rate of 11.13 SEK/EUR was used.

Table 3.4: Cost Assumptions

Symbol	Component	Value	Unit	
C_{ch}	Charge system	$\approx 115,000$	EUR/MW	
C_{dis}	Discharge system	$\approx 215,000$	EUR/MW	
C_{int}	DH & Electrical integration	$\approx 80,000$	EUR/MW	
C_{ov}	Overhead	$\approx 250,000$	EUR/MW	
C_{TES}	Storage system	$\approx 13,000$	EUR/MWh	[71, 51]
N	System lifetime	30	years	[47]
d	Nominal discount rate	7	%	[47]
i	Inflation rate	2.5	%	[47]

The DH and electrical integration costs include the heat exchanger system, whose cost level was estimated using area-based correlations for high-temperature gas-to-liquid heat exchangers reported in [65]. A detailed description of the estimation procedure is provided in Appendix A.1.

3.6.1 Capex calculation

The CAPEX calculation is represented by the following governing equations:

$$C_{storage} = E_{TES}^{max} \cdot C_{TES} \tag{3.24}$$

$$C_{equip} = C_{ch} P_{in,t} + C_{dis} P_{out,th,t} \eta_{elec} + C_{int} P_{out,th,t} \eta_{heat} \tag{3.25}$$

$$CAPEX = (C_{storage} + C_{equip} + C_{ov} P_{in,t}) \tag{3.26}$$

$$CAPEX_{ann} = CAPEX \cdot CRF \tag{3.27}$$

$$\mathrm{CRF} = \frac{r(1+r)^N}{(1+r)^N - 1} \tag{3.28}$$

$$r = \frac{1+d}{1+i} - 1 \tag{3.29}$$

where:

- $C_{storage}$ = total cost of the thermal storage system
- C_{equip} = total cost of the charging and discharging equipment.
- CRF = capital recovery factor
- $CAPEX_{ann}$ = annualized CAPEX of the P2H2P storage system
- r = Discount rate

3.7 Levelized cost of storage, (LCOS)

To complement PBP and PI the levelized cost of storage (LCOS) metric will be used, which is among the most common economic tools to evaluate the economic performance of an energy storage unit. The LCOS represents the average cost per unit of electricity discharged from an energy storage system over its entire lifetime [73]. The expression for LCOS is therefore annualized and defined in equation 3.30, consisting of CAPEX, OPEX, and the annual energy yield (AEY). It can be observed that this is the same expression as the levelized cost of electricity (LCOE) which is technically the same thing except that the LCOS expression is used for the cost of producing electricity from energy storage specifically.

$$\mathrm{LCOS} = \frac{\mathrm{CAPEX_{ann}} + \mathrm{OPEX}}{\mathrm{AEY}} \tag{3.30}$$

Where AEY is:

$$\mathrm{AEY} = \sum_{t=1}^{8760} E_{el,out,t} \cdot \Delta t \tag{3.31}$$

In this thesis, LCOS will be used as a validation tool, specifically compared against values presented in Table 2.3 to make sure results are within a realistic window. Since CHP-based P2H2P systems are rarely studied and presented with LCOS values, LCOS comparison will only be performed on the electricity only case.

4 Results

This chapter presents the computational results of the P2H2P scenario simulations through their corresponding KPIs. The results for each scenario are presented in the same order as in Table 3.1.

For all scenarios excluding the electricity-only configuration, identical CAPEX assumptions are applied, resulting in the same annualized CAPEX for equivalent storage scales. The electricity-only configuration has a slightly lower CAPEX due to the absence of district heating integration and associated heat exchanger costs. The resulting total and annualized CAPEX values derived from the cost assumptions in Table 3.4 are presented in Tables 4.1 and 4.2.

Table 4.1: System investment costs: Total and annualized CAPEX for different storage scales.

Scale (h)	Total CAPEX (MSEK)	Annualized CAPEX (MSEK/yr)
12	164.6	10.0
24	216.7	13.1
48	320.9	19.5
72	425.1	25.8

Table 4.2: System investment costs: Total and annualized CAPEX for different storage scales in electricity-only operation.

Scale (h)	Total CAPEX (MSEK)	Annualized CAPEX (MSEK/yr)
12	156.8	9.5
24	208.9	12.7
48	313.1	19.0
72	417.3	25.3

4.1 Reference case - 2024

This result section presents the 2024 reference scenario, which serves as the benchmark case for all subsequent scenario comparisons. The scenario reflects the observed SE3 electricity market conditions in 2024 and assumes CHP-like operation without electricity consumption tax. The corresponding PI and PBP are presented in Tables 4.3 and 4.4.

Table 4.3: Scenario 1: Reference case 2024: Comparison of PI and system peaks for Model 1 and Model 2.

	Peaks (#)		**Lower Bound (PI)**		**Control Case (PI)**		**Upper Bound (PI)**	
Scale (h)	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**
12	90	51	1.11	0.70	0.89	0.56	0.74	0.47
24	40	29	1.03	0.77	0.82	0.62	0.69	0.51
48	14	18	0.77	0.60	0.62	0.48	0.52	0.40
72	8	14	0.60	0.49	0.48	0.39	0.40	0.33

Table 4.4: Scenario 1: Reference case 2024: Comparison of PBP and system peaks for Model 1 and Model 2.

	Peaks (#)		**Lower Bound (yrs)**		**Control Case (yrs)**		**Upper Bound (yrs)**	
Scale (h)	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**
12	90	51	14.81	23.56	18.51	29.45	22.21	35.35
24	40	29	16.01	21.43	20.01	26.78	24.01	32.14
48	14	18	21.32	27.59	26.65	34.48	31.98	41.38
72	8	14	27.32	33.76	34.14	42.20	40.97	50.64

Model 1 shows some signs of low to break-even economic performance for lower bound CAPEX assumptions at a storage scale of 12 and 24 hours. Across all other storage scales and cost assumptions PI indicates a net negative yearly result for both models. Results for PBP present a similar trend, for smaller storage scales PBP tends to be lower or around the assumed technical lifetime while at larger storage scales PBP increases above the assumed technical lifetime.

4.2 Reference case 2024 - With energy tax

This scenario represents the reference market conditions based on SE3 electricity prices from 2024, while including the Swedish electricity consumption tax. The purpose is to isolate the impact of taxation on P2H2P profitability under benchmark market conditions. For the 2024 reference case with energy tax applied, the PI and PBP are presented in Tables 4.5 and 4.6.

Table 4.5: Scenario 2 reference 2024 - With energy tax : Comparison of PI and system peaks for Model 1 and Model 2.

	Peaks (#)		**Lower Bound (PI)**		**Control Case (PI)**		**Upper Bound (PI)**	
Scale (h)	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**
12	19	15	0.31	0.11	0.24	0.09	0.20	0.08
24	9	15	0.28	0.14	0.23	0.11	0.19	0.09
48	2	14	0.21	0.1	0.17	0.08	0.14	0.06
72	1	13	0.16	0.06	0.13	0.05	0.11	0.04

Table 4.6: Scenario 2 reference 2024 - With energy tax: Comparison of PBP and system peaks for Model 1 and Model 2.

	Peaks (#)		**Lower Bound (yrs)**		**Control Case (yrs)**		**Upper Bound (yrs)**	
Scale (h)	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**
12	19	15	53.83	145.03	67.28	181.28	80.74	217.54
24	9	15	58.56	115.68	73.20	144.60	87.84	173.52
48	2	14	79.34	169.99	99.17	212.49	119	254.99
72	1	13	102.48	260.91	128.10	326.13	153.72	391.36

All storage scales and CAPEX assumptions for both models results in PI values well below 1, indicating poor economic performance. Correspondingly, the payback periods are significantly longer than the assumed technical lifetime of 30 years.

4.3 Year variation 2023

This scenario represents a moderately higher-volatility market environment than the 2024 reference year and is included to assess the sensitivity of P2H2P performance to increased electricity price fluctuations. The corresponding PI and PBP are presented in Tables 4.7 and 4.8.The relative increase in electricity price volatility compared to 2024, measured using the $P95-P5$ range, was found to be $\Delta V_{2023} = 26.3\%$.

Table 4.7: Scenario 3, 2023, without energy tax: Comparison of PI and system peaks for Model 1 and Model 2.

	Peaks (#)		**Lower Bound (PI)**		**Control Case (PI)**		**Upper Bound (PI)**	
Scale (h)	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**
12	89	52	1.15	0.76	0.92	0.61	0.76	0.51
24	43	33	1.02	0.78	0.82	0.62	0.68	0.52
48	18	19	0.75	0.58	0.60	0.47	0.50	0.39
72	12	10	0.59	0.47	0.48	0.38	0.40	0.32

Table 4.8: Scenario 3 2023, without energy tax: Comparison of PBP and system peaks for Model 1 and Model 2.

	Peaks (#)		**Lower Bound (yrs)**		**Control Case (yrs)**		**Upper Bound (yrs)**	
Scale (h)	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**
12	89	52	14.39	21.57	17.98	26.97	21.58	32.36
24	43	33	16.15	21.20	20.18	26.50	24.22	31.80
48	18	19	21.96	28.18	27.45	35.23	32.94	42.27
72	12	10	27.72	34.78	34.65	43.48	41.58	52.17

The results indicate a similar trend as the reference case 2024 scenario. Model 1 shows some signs of low to break even economic performance for lower bound CAPEX assumptions at a storage scale of 12 and 24 hours. Across all other scenarios and cost assumptions results indicate poor economic performance. Even though changes are subtle relative to the year of 2024 there are some performance improvements with slightly higher PI values and lower PBP values.

4.4 Year variation 2025

This result section presents the 2025 scenario, which represents the highest-volatility electricity market environment among the analyzed years. The scenario is included to evaluate how increased electricity price spreads influence the economic performance of the P2H2P system. The corresponding PI and PBP are presented in Tables 4.9 and 4.10. The relative increase in electricity price volatility compared to 2024, measured using the $P95 - P5$ range, was found to be $\Delta V_{2025} = 67.2\%$.

Table 4.9: Scenario 4, 2025: Comparison of PI and system peaks for Model 1 and Model 2.

	Peaks (#)		**Lower Bound (PI)**		**Control Case (PI)**		**Upper Bound (PI)**	
Scale (h)	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**
12	82	55	1.47	0.92	1.18	0.74	0.98	0.62
24	41	29	1.32	0.97	1.06	0.78	0.88	0.65
48	13	16	0.96	0.75	0.77	0.60	0.64	0.50
72	5	4	0.74	0.61	0.59	0.49	0.50	0.41

Table 4.10: Scenario 4, 2025: Comparison of PBP and system peaks for Model 1 and Model 2.

	Peaks (#)		**Lower Bound (yrs)**		**Control Case (yrs)**		**Upper Bound (yrs)**	
Scale (h)	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**
12	82	55	11.18	17.82	13.98	22.28	16.77	26.74
24	41	29	12.47	16.96	15.58	21.20	18.70	25.44
48	13	16	17.16	21.91	21.45	27.38	25.74	32.86
72	5	4	22.20	26.94	27.75	33.68	33.29	40.41

These results exhibit similarities to previous scenarios with indications of some profitability at smaller storage scales and as storage increases, profitability falls. With the exception that 2025 indicates more economically promising results compared to 2023 and 2024.

Additionally Model 2 was evaluated for 2025 using 15-minute pricing data instead of hourly resolution. The resulting KPIs are presented in Tables 4.11 and 4.12.

Table 4.11: Scenario 4, 2025 (15-minute pricing): PI and system peaks for Model 2.

Scale (h)	**Peaks (#)**	**PI (Lower)**	**PI (Control)**	**PI (Upper)**
12	160	1.38	1.11	0.92
24	117	1.71	1.37	1.14
48	83	1.78	1.42	1.18
72	61	1.63	1.31	1.09

Table 4.12: Scenario 4, 2025 (15-minute pricing): PBP and system peaks for Model 2.

Scale (h)	Peaks (#)	PBP (Lower)	PBP (Control)	PBP (Upper)
12	160	11.91	14.89	17.87
24	117	9.64	12.05	14.46
48	83	9.28	11.59	13.91
72	61	10.09	12.62	15.14

Model 2, which in general indicates a lower economic performance across scenarios then Model 1, show very promising economic results when working with 15-minute pricing, with high PIs and low PBPs across several storage scales and CAPEX assumptions. The number of times the storage capacity peaks is also much higher in comparison to hourly resolution. Optimal storage scale also deviates as the 15-minute model presents a result where the 48 h scale application has the highest economic performance which is in contrast to all other results.

4.5 Excess heat replaced with biomass CHP

This scenario considers a district heating system configuration in which excess heat is replaced by biomass-fired CHP production. The purpose is to evaluate P2H2P performance in a district heating system that is more representative of a typical Swedish DH network, where heat production is more dependent on dispatchable generation. The resulting PI and PBP are presented in Tables 4.13 and 4.14.

Table 4.13: Scenario 5: Excess heat replaced with biomass (2024): Comparison of PI and system peaks for Model 1 and Model 2.

	Peaks (#)		**Lower Bound (PI)**		**Control Case (PI)**		**Upper Bound (PI)**	
Scale (h)	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**
12	60	38	1.35	1.03	1.08	0.82	0.90	0.68
24	37	11	1.31	1.04	1.05	0.83	0.87	0.70
48	11	0	0.94	0.77	0.76	0.62	0.63	0.51
72	3	0	0.73	0.60	0.58	0.48	0.48	0.40

Table 4.14: Scenario 5: Excess heat replaced with biomass (2024): Comparison of PBP and system peaks for Model 1 and Model 2.

	Peaks (#)		**Lower Bound (yrs)**		**Control Case (yrs)**		**Upper Bound (yrs)**	
Scale (h)	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**
12	60	38	12.21	16.05	15.26	20.06	18.31	24.07
24	37	11	12.58	15.80	15.73	19.75	18.87	23.70
48	11	0	17.45	21.37	21.82	26.71	26.18	32.05
72	3	0	22.71	27.49	28.39	34.36	34.07	41.24

The results indicate higher profitability in comparison to the reference case, yet still poor economic performance especially for larger storage scales. The results also show that the total number peaks are lower for this scenario for both models in comparison to the reference case.

4.6 Electricity only

This scenario represents electricity-only operation, where the P2H2P system does not deliver heat to the district heating network. As detailed in the methodology, this configuration increases the electrical round-trip efficiency (RTE) to 55% by allocating all recovered energy to electricity generation. The resulting PI and PBP are presented in Tables 4.15 and 4.16. To facilitate comparison with other electrical energy storage technologies and reported values for similar P2H2P systems, the LCOS was calculated for each storage scale and model, as shown in Table 4.17.

Table 4.15: Scenario 6: Electricity only (55%): Comparison of PI and system peaks for Model 1 and Model 2.

	Peaks (#)		Lower Bound (PI)		Control Case (PI)		Upper Bound (PI)	
Scale (h)	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**
12	75	45	1.18	0.78	0.95	0.63	0.79	0.52
24	29	19	1.07	0.88	0.86	0.70	0.71	0.59
48	10	3	0.78	0.68	0.63	0.55	0.52	0.45
72	5	0	0.61	0.53	0.49	0.42	0.41	0.35

Table 4.16: Scenario 6: Electricity only (55%): Comparison of PBP and system peaks for Model 1 and Model 2.

	Peaks (#)		Lower Bound (yrs)		Control Case (yrs)		Upper Bound (yrs)	
Scale (h)	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**
12	75	45	13.93	21.04	17.41	26.30	20.89	31.56
24	29	19	15.38	18.75	19.23	23.44	23.08	28.13
48	10	3	21.05	24.18	26.31	30.23	31.57	36.27
72	5	0	27.01	31.13	33.77	38.91	40.52	46.69

Table 4.17: Comparison of LCOS for model 1 and model 2 across different storage sizes.

	LCOS Lower (SEK/MWh)		LCOS Control (SEK/MWh)		LCOS Upper (SEK/MWh)	
Scale (h)	**M1**	**M2**	**M1**	**M2**	**M1**	**M2**
12	732	907	861	1,072	989	1,238
24	828	886	974	1,050	1,121	1,213
48	1,083	1,107	1,292	1,329	1,501	1,551
72	1,339	1,383	1,611	1,675	1,883	1,967

The resulting PI and PBP reflect low or break-even economic profitability for small scale operation for Model 1 at the lower bound CAPEX assumption while the remaining KPIs under different storage-scale and CAPEX assumptions fall below a PI of 1. The LCOS range from 732-1,238 SEK/MWh for the 12h case, 828-1,213

SEK/MWh for 24h, 1,083-1,551 SEK/MWh for 48h, and 1,339-1,967 SEK/MWh for 72h.

5
Scenario analysis

This chapter synthesizes the preceding individual scenario results to provide a comprehensive overview of the system's performance and economic sensitivity. By examining the interplay between operational dispatch strategies, revenue generation, and cost structures, this analysis evaluates how market conditions and technical configurations influence the long-term viability of the P2H2P system.

5.1 PBP comparison

This subsection presents the PBP across various techno-economic scenarios and system models. In the following figures, circular markers represent "Model 1" while square markers represent "Model 2," as defined in the respective legends. The Y-axis represents the PBP in years, while the X-axis categorizes results by storage capacity. To facilitate comparison, each storage size is highlighted by a distinct gray-shaded vertical pillar where all data points within a pillar correspond to that specific storage time.

5.1.1 Impact of taxation policy

Figure 5.1 provides a overview of the PBP for all primary scenarios. The 2025 quarterly pricing results are exempted.

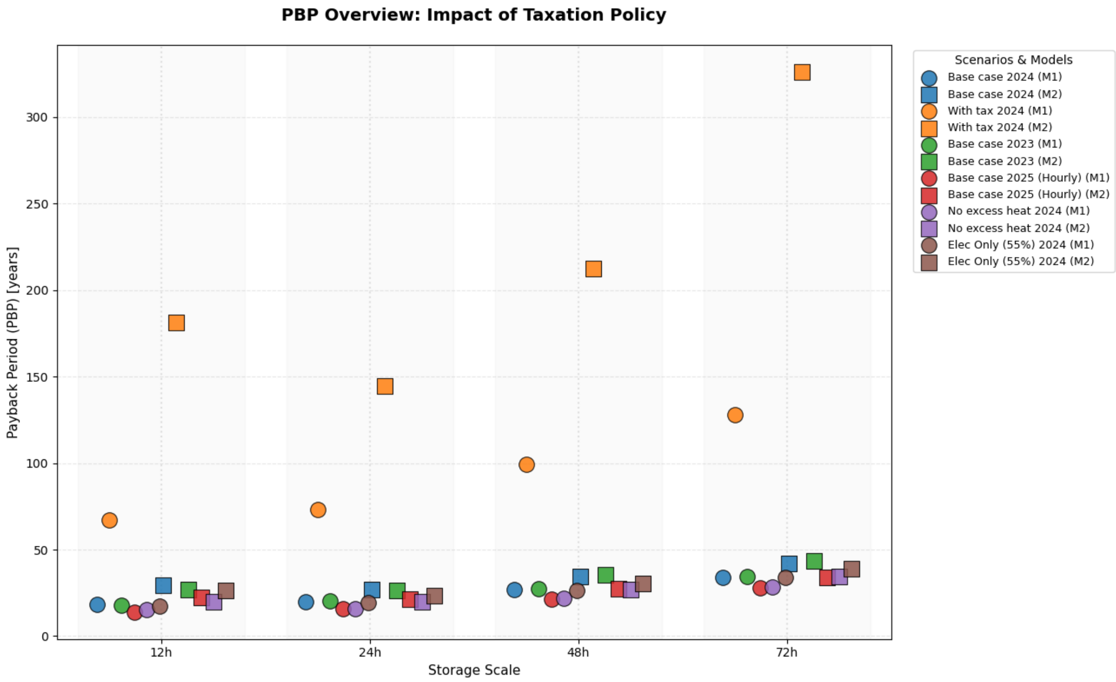

Figure 5.1: PBP overview including the impact of the Swedish electricity consumption tax. The scenario labelled "With tax" includes the electricity consumption tax, while all other scenarios are assumed to be tax-exempted.

The results clearly demonstrate the impact of electricity consumption tax on system feasibility. Under the current taxation framework, the projected PBP is substantially increased, suggesting that such plants are not economically viable without tax exemptions or modified policy incentives. This consumption tax alters the behavior of the plant since adding the tax requires higher peak prices to trigger discharge.

5.1.2 Scenarios compared (tax-exempted)

Figure 5.2 presents the same dataset as Figure 5.1, but with the "With tax" scenario excluded. This adjustment recalibrates the Y-axis scale, allowing for a more granular visualization of the spread between the remaining economic and technical variations.

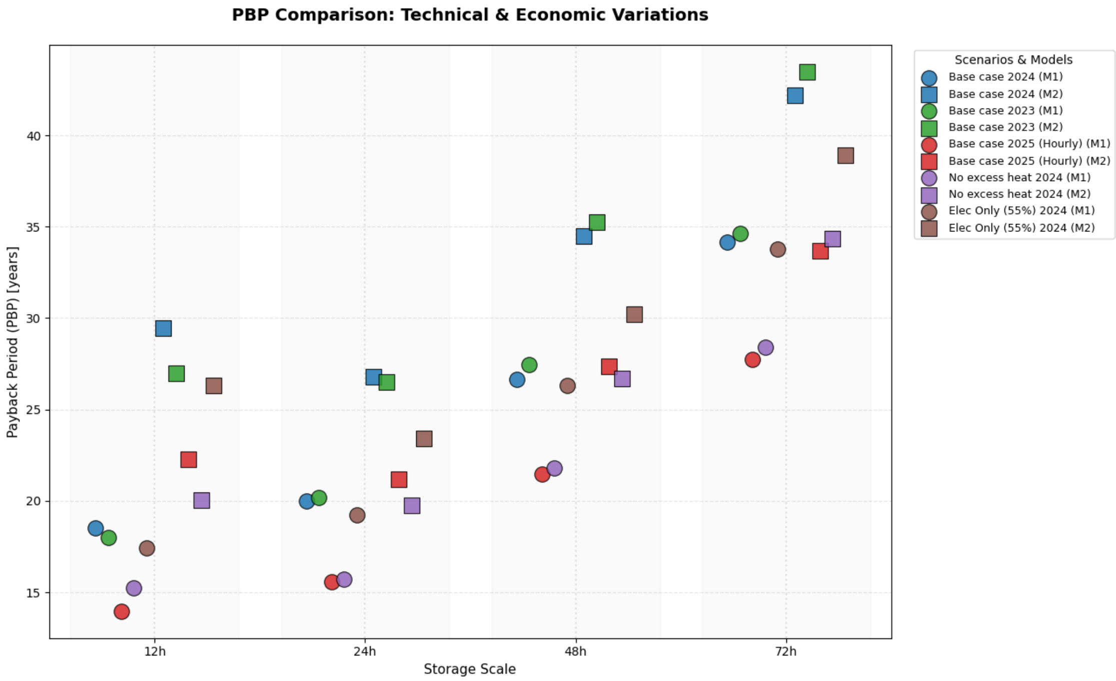

Figure 5.2: PBP comparison across technical and economic variations, excluding taxation to highlight the sensitivity of the remaining scenarios.

This comparison highlights how factors such as energy market fluctuations (2024 vs. 2023/2025) and technical constraints such as electricity-only vs. CHP influence the return on investment. The plot also shows a clear visualization of how the PBP is affected by storage size which the two models shows trend-lines of.

5.1.3 Impact of temporal price resolution

Figure 5.3 isolates the performance of "Model 2" for 2025 to compare the effects of hourly average pricing versus quarterly (15-minute) pricing. While the hourly average is derived directly from the quarterly data, the higher temporal resolution of the quarterly scenario allows the model to capture extreme price volatility, specifically the ability to charge during momentary price troughs and discharge during peak spikes.

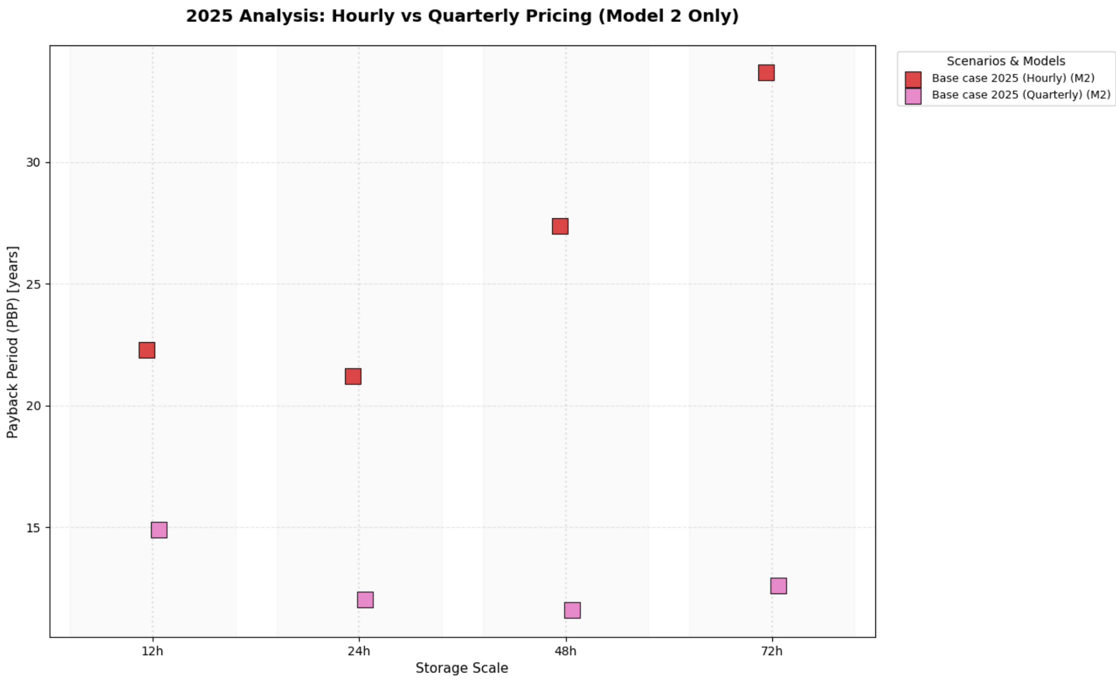

Figure 5.3: Comparison of PBP for Model 2 using hourly vs. quarterly price resolution (Base Case 2025). Higher resolution captures price volatility more effectively, improving economic performance.

These results underscore that utilizing high-frequency price variations are a critical driver for profitability, as the quarterly pricing consistently yields shorter payback periods across all storage scales. Interestingly the storage size is not as sensitive to upscaling when applying quarterly hour pricing, implying increased profitability with increased cycling. The number of cycles for hourly and quarterly pricing is shown in Table 5.1.

Table 5.1: Comparison of cycle counts for hourly and quarterly pricing for 2025.

Scale (h)	Hourly Pricing	Quarterly Pricing
12	59.79	115.64
24	38.66	84.62
48	21.32	59.12
72	14.63	46.09

5.2 Peak counter

The peak counter is utilized as a metric to evaluate the utilization and adequacy of the TES capacity. Unlike traditional cycle counting, which measures total energy throughput, the peak counter records the frequency at which the storage reaches its maximum state-of-charge. A high peak count in smaller storage scales suggests that the system is frequently "bottlenecked," potentially leaving profitable arbitrage opportunities untapped due to volume constraints. Conversely, a low peak count in larger scales (48h–72h) indicates that the storage is rarely fully utilized, suggesting that the marginal investment in additional tank volume may not be economically justified under the simulated market conditions. Figure 5.4 showcases the trendline for the peaks in the different scenarios.

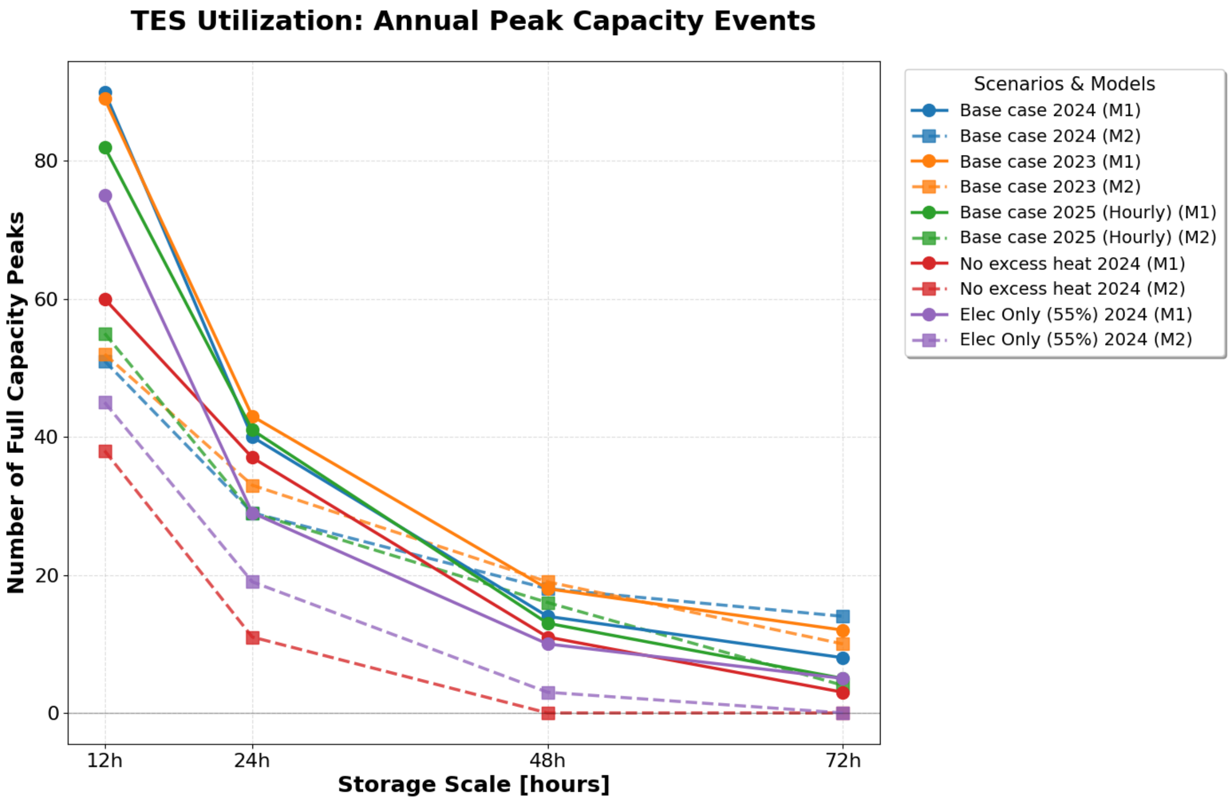

Figure 5.4: Annual peak capacity events across all TES storage sizes for all but with tax scenario.

As shown in figure 5.4, the frequency of peak events decreases as storage capacity increases across all scenarios. For the 12h and 24h scales, Model 2 generally achieves fewer peaks than Model 1, suggesting a more selective or optimized dispatch strategy. A notable exception is the "Base Case 2024 (With Tax)" scenario which has been removed due to irregular behavior.

In the "No excess heat" and "Elec only (55%)" scenarios, the peak counter drops toward zero at the 72h scale. This identifies a clear threshold where the storage capacity exceeds the system's ability to fully charge within the given market fluctuations, rendering the additional volume redundant.

5.3 Revenue share

This section examines the proportional contribution of electricity sales and DH cost savings to the total annual revenue. In Figure 5.5, the solid colored base of each bar represents electricity revenue, while the hatched upper sections represent the DH savings. "Model 1" is distinguished by diagonal hatching (///), while "Model 2" utilizes a dotted pattern (...).

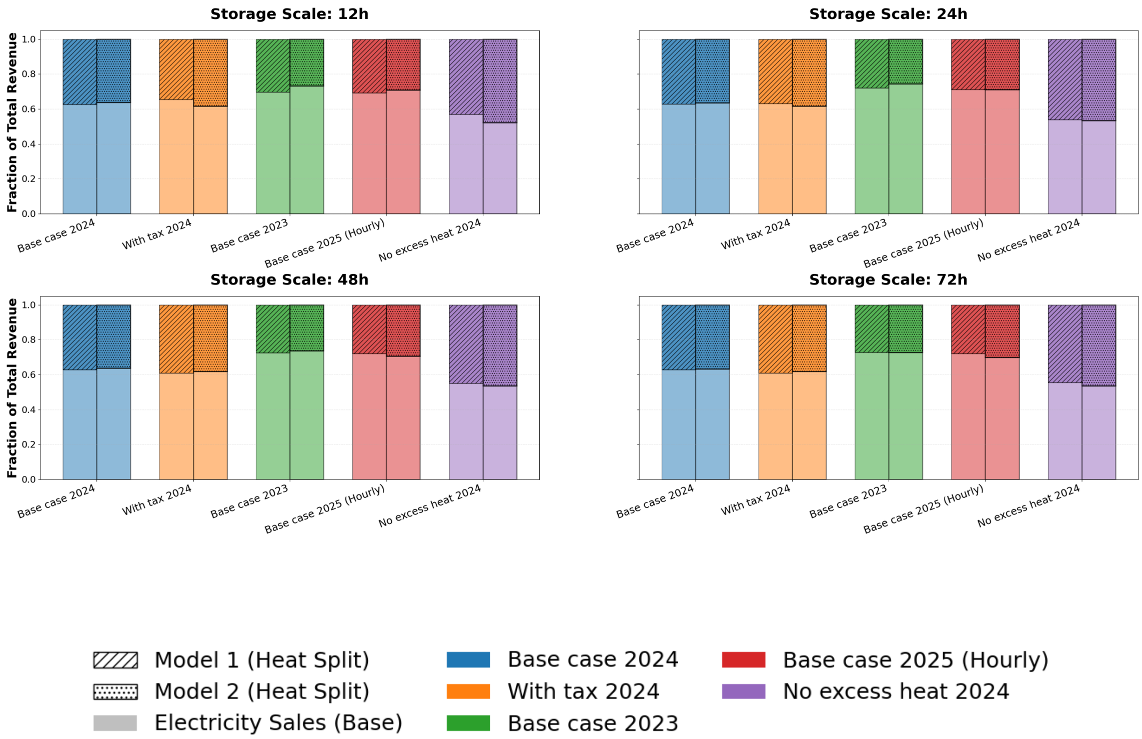

Figure 5.5: Revenue composition comparison: Electricity in solid vs. heat in hatched for Model 1 and Model 2.

The visualization reveals a consistent trend that the fraction of revenue derived from DH system savings is remarkably similar for both simulation models across all scenarios. As the storage scale increases from 12h to 72h, the revenue composition remains relatively stable, suggesting that the storage duration does not fundamentally alter the balance between heat and power prioritization for these specific market conditions.

The comparison between the 2023, 2024, and 2025 scenarios highlights how different market conditions affect the relative contribution of electricity arbitrage and district heating revenues to the total system value. In the 2024 case, the share of DH savings is slightly higher compared to 2023 and 2025 which are characterized by higher price variations. However, it must be noted that the DH demand data utilized in all simulations is from 2024, as stated in the methodology. As a result, certain conclusions regarding the differences between these years cannot be definitively drawn, as the heat demand profile remained static while electricity prices changed year-to-year.

In the 'No excess heat 2024' scenario, the share of DH-derived revenue increases for both simulation models. This aligns with expectations, as the higher DH-system costs render P2H2P operations more economically viable.

5.4 Cost share

This section examines the proportional contribution of CAPEX and charging costs to the total annual system expenditure. In Figure 5.5, the solid colored base of each bar represents the annualized CAPEX, while the hatched upper sections represent the variable charging costs. "Model 1" is distinguished by diagonal hatching (///), while "Model 2" utilizes a dotted pattern (...). All values are normalized to show the relative cost composition, allowing for a direct comparison of cost structures regardless of the absolute magnitude of investment.

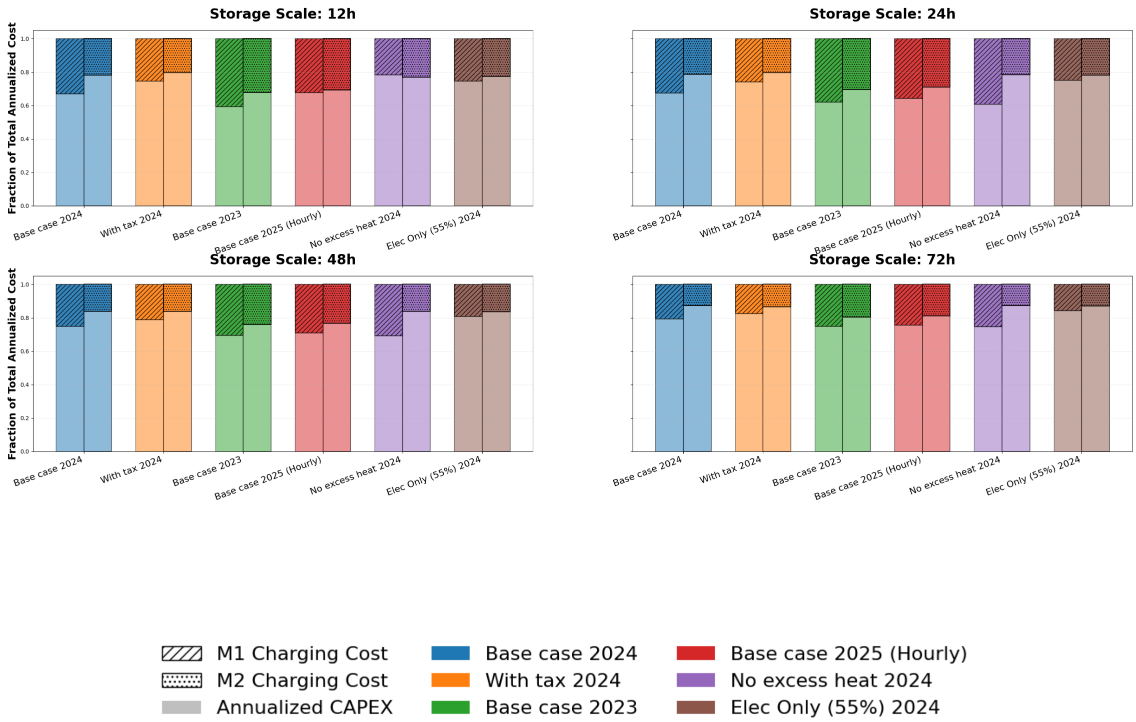

Figure 5.6: Cost share comparison: Annualized CAPEX in solid vs. charging costs hatched for Model 1 and Model 2.

The visualization reveals that the total annual cost is heavily dominated by CAPEX across all scenarios, with charging costs representing a secondary, albeit variable, fraction of the total expenditure. As the storage scale increases from 12h to 72h, the relative share of CAPEX remains the primary driver of system cost. This again signals the need for using the system more. However, a slight shift in the composition is observable in larger storage scales, where charging costs become less significant compared to the static capital recovery costs.

6

Discussion

The results of this study indicate better economic performance for Model 1 compared to Model 2 for all scenarios, which is expected considering Model 1 has a more optimistic model structure with perfect yearly foresight. Model 2, which operates on price triggers on a moving price average has a more pessimistic structure and does not capture all price spreads perfectly. The truth likely lies somewhere in between the two models. Although they operate under different operational assumptions, both models show the overall trend for the different scenarios strengthening this thesis's research objective. However, due to the fact that specific results differentiate somewhat and the uncertainty regarding CAPEX for P2H2P systems, they should be interpreted as indicative rather than definitive.

6.1 Validation and LCOS

In terms of method validation, the LCOS obtained for the electricity-only scenario with optimized 12-24h storage scaling ranged from 732-1,238 SEK/MWh for the 12h case and 828-1,213 SEK/MWh for the 24h case. These values are somewhat lower than the range presented in Table 2.3, where reported LCOS values for PTES systems were between 990–1270 SEK/MWh.

One important difference is that the present study uses empirically observed hourly electricity prices for SE3 during 2024, for which the annual mean price was approximately 35.77 EUR/MWh [69]. In contrast, the comparison values in Table 2.3 were based on a fixed charging electricity price of 30 EUR/MWh. The use of hourly varying electricity prices enables the optimization model to charge the storage system only during economically favorable periods, thereby improving arbitrage opportunities and potentially reducing the resulting LCOS.

The lower LCOS values obtained in this study may also reflect optimistic operational and/or CAPEX assumptions. However, despite these differences in methodology and input assumptions, the resulting LCOS values remain within the same general range as previously reported PTES systems. This agreement in magnitude suggests that the modeling framework and cost assumptions approach produced economically plausible results in accordance with reported literature.

6.2 Electricity consumption tax

The P2H2P system is not economically viable when subject to the current Swedish electricity consumption tax. The KPIs indicate very low economic performance, as the model operates only rarely under these conditions. The inclusion of the energy tax significantly increases charging costs, making electricity and heat sales seldom profitable. As shown in the results in Table 4.5 and 4.6, the application of electricity consumption taxes suppresses the PI well below 1.0, with values dropping as low as 0.04 for the least profitable configuration. PBP frequently exceeds 100+ years which is vastly above the approximated 30-year technical lifetime of the plant.

This economic erosion is directly influenced by the system's operational strategy. The consumption tax effectively increases the marginal cost of storage charging. The consequence is that the models require significantly higher electricity price spreads to trigger a discharge cycle. As a result, the optimization algorithm restricts the number of annual operational peaks to remain cost-avoidant. This leads to a system that remains idle to avoid tax-burdened charging costs, failing to generate sufficient revenue to amortize its capital expenditure.

These findings suggest that under the current tax regime , P2H2P technologies likely cannot be competitive under current market conditions, necessitating either targeted tax exemptions or modernized policy incentives to facilitate adoption.

6.3 Market dynamics and volatility

The 2023 and 2025 scenarios exhibit improved economic performance compared to the 2024 reference case. This is consistent with the higher price volatility observed in these years, which creates more arbitrage opportunities and results in more frequent system operation. While performance improvements are observed across both models, only marginal variation is seen in peak frequency. For both models, there is a slight increase in peak frequency for 2023 and a slight decrease for 2025. However, these effects are limited in magnitude and indicate that the observed level of price volatility does not appear to significantly influence the degree of storage utilization across configurations.

While these results suggest that increased price volatility can improve system performance, the effect is relatively limited. A significantly higher level of volatility than observed in these years would likely be required to substantially enhance the economic performance of the P2H2P system used in this study. In addition, future electricity price volatility remains uncertain. Although increasing shares of intermittent generation may contribute to greater price volatility, the deployment of flexibility measures such as P2H2P systems, alternative energy storage technologies and other balancing measures may counteract this effect. There is no guarantee that future market conditions will exhibit sufficient volatility to substantially improve the economic performance of the P2H2P system considered in this study.

The results are also subject to methodological limitations, as the 2024 heat demand profile was applied to the 2023 and 2025 electricity price scenarios. This may introduce unrealistic operating conditions where low electricity prices coincide with high heat demand and high heat value. In practice, heat demand and electricity prices often exhibit correlated seasonal behavior, meaning that periods of high heat demand are commonly associated with higher electricity prices. This means the economic value of CHP operation may be overestimated in some periods.

6.4 No excess heat and electricity-only scenarios

Both the "no excess heat" and the "electricity only" scenarios show improved economic performance compared to the 2024 reference case. In the "no excess heat" case, replacing excess heat with biomass-fired CHP increases the value of heat, strengthening the incentive to discharge as described under Section "Revenue Share" 5.3.

In the electricity-only case, the improved performance is driven by a combination of higher electricity value relative to heat, a higher round-trip efficiency (RTE = 0.55), and slightly lower investment costs due to the absence of a heat exchanger. Although the combined heat and power configurations also capture value from heat, the higher market value of electricity together with the more efficient electricity-to-electricity conversion provides superior arbitrage opportunities.

In both scenarios, the increased value of discharging leads to more frequent partial charging cycles. As a result, the number of peak charging events decreases compared to the reference case. This represents a system that prioritizes rapid charging and discharging over full charging cycles in order to improve economic performance. Although the overall effect remains relatively limited in this study, the trend is consistent across both models and all system scales.

6.5 Quarter-hour pricing

When Model 2 is simulated using quarter-hour electricity price intervals for 2025, the economic performance improves significantly compared to the hourly resolution case. This is because the model can capture intra-hour price variations, allowing it to exploit short-term price spikes and valleys more effectively. As a result, the system can charge and discharge over shorter time intervals at more favorable price levels, which enhances arbitrage opportunities.

The higher temporal resolution leads to more efficient utilization of the storage capacity and to shift in the optimal storage scale from approximately 24 hours to 48 hours compared to the hourly case. In addition, the frequency of peak charging events increases significantly under 15-minute pricing. The increased peak frequency together with the shift toward larger optimal storage capacities suggests that the system does not primarily benefit from rapid intra-hour cycling. Instead, the higher temporal resolution improves the system's ability to identify favorable intra-hour price variations and better time charging and discharging events. This leads to more effective utilization of the storage capacity and improved economic performance.

These results indicate promising economic performance under the assumption that a P2H2P system can physically operate under 15-minute intervals. The dynamic response of P2H2P systems is likely constrained by the turbomachinery and the thermal components. This likely causes the model to overestimate the system's ability to exploit short-duration price variations. Suggesting that the economic benefits observed under 15-minute resolution are optimistic, particularly for systems with significant thermal coupling. This favors electricity-only operation for P2H2P systems. The absence of district heating integration constraints may enable the system to exploit shorter-duration price fluctuations.

6.6 Storage scale

As mentioned in Section 2.5.4, P2H2P systems are in theory expected to scale favorably with increasing storage capacity. Given that the storage component represents the lowest cost share of the overall system, i.e., compared to the charging and discharging stages. Under hourly resolution this study identifies an optimal storage scale in the range of 12–24 hours of discharge, with larger storage sizes resulting in weaker economic performance. Although these results are specific to this study and uncertainties regarding storage CAPEX assumptions could alter the optimal storage duration. The results highlight an important scaling insight. Namely, that the optimal system size is dependent on the market condition under which the P2H2P unit operates in.

This study finds that optimal storage scale is also dependent on P2H2P system characteristics and control strategy. The difference in peak frequency behavior across scenarios supports this observation. The electricity only and no excess heat scenarios have a reduced peak frequency yet improved economic performance. This suggests that profitability is more strongly linked to arbitrage opportunities than to storage utilization. In contrast, the quarter-hour (15-minute) pricing scenario exhibits both improved economic performance and an increase in peak frequency, together with a shift toward larger optimal storage capacities.

6.7 Revenue drivers

The economic value of electricity arbitrage exceeds that of heat production across all scenarios, despite heat accounting for a larger share of the total energy output.

The most likely explanation for this result is the higher market value of electricity compared to heat on an energy basis. Furthermore, the economic value from heat production is influenced by the ownership structure of the district heating system. If the P2H2P unit is operated by the district heating system owner, the full value of the delivered heat can be utilized within the system. In contrast, an independent operator would likely depend on negotiated heat prices and access to the district heating network.

6.8 Economic synthesis

By comparing the revenue composition in Figure 5.5 with the cost structure in Figure 5.6, it becomes evident that the system is overwhelmingly CAPEX-intensive. While the operational dispatch strategy demonstrates distinct differences in cost-to-revenue ratios between Model 1 and Model 2, these operational variations are secondary to the fixed capital recovery requirements. Ultimately, this suggests that while marginal optimizations in dispatch logic are valuable, the economic feasibility of P2H2P systems is more strongly dependent on reducing the investment costs and complexity of the P2H2P system.

The system's feasibility is highly sensitive to the baseline CAPEX assumptions. Although TES costs could increase for systems requiring advanced storage materials, higher operating temperatures, or extensive insulation, the applied cost scaling may also overestimate storage costs for larger systems. Large-scale sensible thermal storage may exhibit favorable scaling characteristics due to strong thermal inertia and reduced relative heat losses at larger storage volumes.

Increasing the storage duration from 12 to 72 hours increased the total CAPEX by approximately a factor of 2.6, despite the storage capacity increasing sixfold. Although the storage unit represents a non-negligible share of the total system cost, this indicates that the dominant cost contribution is associated with power capacity, represented by the charging and discharging turbomachinery and the heat exchanger system, rather than the storage volume itself. As discussed in the theoretical framework, increased operating temperatures and system complexity strongly influence the cost of these components, introducing additional CAPEX uncertainty. This uncertainty is particularly significant for the heat exchanger system, where the thermal profile and resulting heat exchanger design may introduce both technical and economic risks that could erode marginal profitability. The costs are impossible to know for certain since most of this type of projects is in its study phase and are dependent on estimates from similar technologies.

6.9 Electricity-only operation

As discussed in Sections 6.5 and 6.7, the advantages associated with intra-hour pricing together with the relatively higher economic value of electricity compared to heat favor less complex electricity-only configurations. From a policy perspective, current Swedish taxation structures also favor electricity-only operation. Electricity consumption for heat production within Swedish district heating systems is subject to taxation, which may disadvantage CHP-type operation.

Furthermore, PTES-based P2H2P concepts, often considered among the most promising P2H2P technologies, rely on recuperating turbine exit heat to achieve high electrical efficiencies. PTES systems are still in a research and development phase and may potentially achieve electrical round-trip efficiencies well above 55%. However, such performance is often reported under the assumption that no external heat extraction occurs. The sensitivity of PTES systems to external heat utilization has not been quantified in this study and would require further investigation in order to determine whether such systems should operate entirely as electricity-only configurations.

6.10 The future of P2H2P

Overall, these theis results suggest that future P2H2P development under similar market conditions may benefit from focusing on simplified and operationally flexible electricity-oriented configurations with lower capital intensity, rather than highly integrated CHP-type systems optimized primarily for maximum efficiency. At the same time, policy conditions such as electricity taxation appear to have a decisive influence on system viability.

Despite the limited profitability observed in several scenarios, the long-term need for large-scale flexibility solutions is still expected to increase with higher shares of variable renewable electricity generation and increased occurrence of prolonged low-generation periods such as Dunkelflaute events. In this broader power system context, continued improvements in round-trip efficiency remain important for reducing balancing losses and limiting total system-wide energy requirements.

7

Conclusions

The aim of this master's thesis was to analyze how a representative P2H2P system performs under real-world market conditions, policy conditions, and operational strategies. The questions stated in the scope of this study presented in Section 1.2 will be answered in the listed format below:

1.) Scenario-Based System Performance - *How does the economic performance of a representative P2H2P system vary under different external system conditions?*

- What is the impact of the Swedish electricity consumption tax on system profitability when comparing current taxation levels to a no-tax scenario?

This thesis finds that no economic feasibility exists for a P2H2P system operating under the studied SE3 and DH market conditions under the current Swedish taxation policy.

- How does system performance vary across electricity price regimes with different levels of volatility, based on historical price data from 2023, 2024, and 2025 in the SE3 electricity market?

The higher electricity price volatility observed in 2023 and 2025 relative to 2024 is beneficial for the economic performance of P2H2P systems. However, the magnitude of this effect remains limited and results only in marginal economic gains.

- How is system performance affected by different district heating systems, such as biofuel-based or excess heat-dominated systems?

District heating systems with lower availability of excess heat, such as biomass-based systems, improve the economic performance of CHP-like P2H2P systems by increasing the value of discharged heat. However, the overall economic performance remains limited under the studied market conditions.

2.) Operational Sensitivity - *How sensitive is a representative P2H2P system's performance to operational parameters*

- Does P2H2P performance increase with the scale of the energy-to-power ratio (i.e., storage duration, MWh/MW)?

While P2H2P is theoretically expected to scale economically with storage size, the optimal storage duration was found in this thesis to depend on external market conditions, operational strategy and dynamic flexibility.

- How does the choice of operational strategy influence system value?
  - Operation as a combined heat and power (CHP-like) system delivering both heat and electricity.
  - Operation focused solely on electricity market participation (power-only mode).

Electricity-only operation provides the highest economic value under the studied market conditions due to the relatively higher value of electricity relative to heat, improved round-trip efficiency, and lower system complexity.

8
Future work

- **P2H2P for future power system balancing**
  This study centered on day-ahead arbitrage, but weather-dependent power systems will increasingly face extended imbalances lasting up to a week due to wind variations. Future work should investigate the role of P2H2P systems in managing these medium-to-long-term supply-demand gaps. Additionally, it should assess how this longer-term balancing capability can be combined with participation in ancillary service markets.

  Particular attention should be given to the dynamic capabilities of different P2H2P configurations. While thermal storage systems are generally slower than battery energy storage systems, they may offer advantages in terms of energy capacity, discharge duration, and cycling capability. Understanding the technical response characteristics, ramp rates, and operational limitations of different P2H2P concepts is therefore essential for evaluating their future role in balancing increasingly weather-dependent electricity systems.

  In addition, future studies should investigate how the economic value of balancing services compares to conventional electricity arbitrage. As renewable penetration increases, price volatility, scarcity events, and flexibility requirements are expected to change significantly. Quantifying how these developments affect the relative value of different revenue streams would provide a more comprehensive assessment of the long-term viability of P2H2P technologies.

- **District Heating-based TES charging**
  The present study assumes that the thermal energy storage is charged exclusively using electricity purchased from the power market. However, future P2H2P systems integrated with district heating networks could potentially charge the storage directly using low-cost thermal energy from external sources, utilizing a boiler to boost the temperature to the required level.

  Such an operational strategy could increase storage utilization and improve overall system economics by reducing dependence on electricity price spreads. At the same time, charging the storage with externally supplied heat would fundamentally alter the operational logic of the system and potentially reduce the importance of electrical round-trip efficiency as the primary performance metric. Instead, the value of stored thermal energy and the interaction with district heating system operation would become increasingly important.

Future research should therefore investigate under which market conditions thermal charging becomes economically attractive, how it affects optimal storage sizing, and whether hybrid charging strategies combining both electrical and thermal charging could provide additional system value.

- **Heat utilization in PTES systems**
  This thesis identified a clear research gap regarding how forerunner P2H2P systems, particularly PTES-based energy storage systems, are affected by external heat utilization. As discussed in Sections 2.5.6 and 2.5.5, existing research strongly suggests that heat extraction negatively affects both electrical round-trip efficiency and dynamic flexibility. However, the actual magnitude of these effects, and the role that the surrounding district heating system plays in enabling heat delivery, were not quantified in this study and remain important objectives for future research on CHP-like P2H2P configurations.

  The most likely outcome would be a trade-off between heat exchanger area, electrical round-trip efficiency, and system cost. Increasing the heat exchanger area could reduce exergy losses and thereby improve electrical round-trip efficiency. However, such improvements would likely come at substantially higher investment costs, particularly for gas-based PTES systems where heat exchanger requirements are already significant.

- **Hybrid CHP and electricity-only operation**
  The findings of this report raise the question of whether a hybrid operational strategy where the system switches between electricity only and heat-coupled operation depending on market conditions could provide improved performance. Such a strategy could potentially improve overall economic performance by balancing the higher electrical value and efficiency of electricity-only operation with the additional revenue streams from heat delivery during favorable district heating conditions.

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A

Appendix 1

A.1 Cost estimate heat exchanger

The investment cost of the heat exchanger supplying useful heat to the district heating system was estimated using the area-based correlation proposed by [65]:

$$C_{HX} = 30800 + 750 \cdot f_p \cdot f_m \cdot A^{0.81} \tag{A.1}$$

where A is the heat exchanger area, f_p is the pressure factor and f_m is the material factor. Moderate operating pressures were assumed ($f_p = 1$). Since the operating temperature remained below 400°C, the material factor was assumed as $f_m = 1$. The heat exchanger area was calculated using the LMTD method:

$$A = \frac{q}{U \cdot \Delta T_{LMTD}} \tag{A.2}$$

where q represents the heat transfer duty corresponding to $\eta_{heat} P_{out,th,t}$. The overall heat transfer coefficient was assumed as:

$$U = 55 \text{ W/m}^2\text{K} \tag{A.3}$$

based on gas-to-liquid heat exchanger values reported in [75].

The district heating system was assumed to operate between 50°C return temperature and 90°C supply temperature. The turbine exhaust temperature was assumed to be approximately 385°C, while the hot-stream outlet temperature after heat extraction was assumed as 260°C. These assumptions yield an estimated logarithmic mean temperature difference of approximately:

$$\Delta T_{LMTD} \approx 250 \text{ K} \tag{A.4}$$

The assumed hot-stream outlet temperature was selected to maintain consistency with the thermodynamic performance assumptions of the system model, since increased heat extraction directly affects the electrical round-trip efficiency.

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